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20 June 2008

Dear Rachel

Electricity Distribution Price Control Review (DPCR5): Initial Consultation Document

The results of the Government's Energy Review and the recent adoption of EU targets for 20% of all energy used to come from renewable sources by 2020 are likely to result in dramatic changes to the roles of distribution companies and the nature of distribution networks. However, what is still to be determined is how far-reaching the changes will be or, perhaps more importantly, how quickly they will be required.

At your workshop in May, and within your initial consultation document, you have challenged all stakeholders to help Ofgem to determine the answers to these questions. My colleagues and I at Electricity North West are keen to do so and to play our part in tackling the biggest challenge to electricity distribution since the rural electrification programmes of the 1950s. Indeed, we have included a considerable volume of analysis and opinion on many of the detailed points raised in your consultation in this response. But before we rush into the debate I think it appropriate to draw back and consider the issues from a more strategic perspective.

It seems very unlikely that we will identify any definitive answers to the questions of how much change and how quickly by the end of 2009; however, the absence of prescriptive solutions does not stop us from ensuring that we can move forward towards the country's environmental goals. Our emphasis in DPCR5 should be on ensuring that companies, regulators and, most importantly, the regulatory framework are well prepared to enable and to support the necessary responses to these challenges in a timely and flexible manner.

We have electricity distribution networks that are efficient and well run, investment is currently funded despite turbulent capital markets and continues to grow steadily and the service experienced by customers has improved dramatically with a high degree of confidence that this can be maintained. If it were not for the fact that there are likely to be huge changes in the energy market place in the next decade this price control review would afford Ofgem the opportunity to develop the existing mechanisms to create one of the most effective and sophisticated regulatory regimes in the world.

A regulatory regime that is ready to address the changes we foresee or indeed the changes we do not foresee requires two key attributes; firstly, a stable platform to ensure the

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continuing confidence of investors and the availability of funds when investment is required and secondly, the ability to recognise and encourage the right behaviours when they are required. We believe the pursuit of these two attributes should be the guiding strategy behind the development of DPCR5. Consistency in the established and proven elements of the regulatory framework will provide the anchor points from which companies can set out with Ofgem to explore the uncertain waters of new environmental incentives. Without some comfort about the treatment of the more familiar risks in electricity distribution, the new risks and uncertainties associated with the development of a low carbon economy are likely to be detrimental to network companies and customers.

The other precept I believe could guide us through this price control process, is the recognition that it is not essential to work out the detail of every solution within the next eighteen months. The price control review can set out a clear strategy and approach enabling companies and regulators to develop new techniques and discover further data as we work through the five years to 2015. We also have the opportunity to develop any more fundamental change to the regulatory framework through the recently announced Review of RPI–X at 20, which could then be developed for implementation as part of DPCR6.

The scale of the challenges that face us may be considerable, but I believe we are well equipped to tackle them together. We are committed to whole-hearted and constructive engagement with Ofgem and see a willingness for this approach to be reciprocated. As the whole team at ENW look forward to working with you on developing the framework for this price control review our watch words will be **stability, consistency, incentives and flexibility,** because in a regime based upon these principles we can pledge the following:

- In a stable regulatory regime we will build robust investment cases based on long-term stewardship of assets.
- In a consistent regulatory regime that maintains investor confidence we will bring the necessary funding to ensure that service levels are maintained and customers are not faced with unnecessary price volatility.
- In an incentive based regulatory regime we will make the choices that demonstrate the desired behaviours.
- In a flexible regime we will innovate to find new solutions.

The challenges may be significant, but I am sure the price control review process will be absorbing and stimulating and I believe there is cause for much optimism.

Yours sincerely,

Digitally signed by Paul Bircham
Reason: I am approving this document
Date: 2008.06.20 18:21:05 +01'00'

Paul Bircham
Regulation Director
Electricity North West Limited

Electricity Distribution Price Control Review (DPCR5): Initial Consultation Document

Electricity North West Response

1. Executive summary

1.1. Introduction

This summary contains a précis of the key points in our response to each chapter of the Initial Consultation document. Our more detailed thoughts on each chapter are contained in the enclosed attachment, including a list of our answers to all of the specific questions raised and relevant appendicies. We recognise that this response will be read by a large number of different people at Ofgem and amongst our wider stakeholders. We have deliberately structured our response so that each section stands on its own, incorporating all relevant arguments. In adopting this structure we acknowledge that this approach does generate some repetition, but it does allow a reader to review an individual chapter or just the answers to questions.

We found the document to be comprehensive and well considered, exploring most of the significant issues in sufficient detail to enable all stakeholders to understand the development of Ofgem's thinking. Furthermore, Ofgem's thinking is sufficiently well developed to prompt DNOs, in particular, to react to these issues in a thorough manner, kick-starting the debate and making Ofgem's stated ambition of concluding the policy debate with a paper in December more realistic.

This objective will also become more achievable if we collectively focus our efforts on the essential activities. Much of the regulatory framework developed over the first four price control reviews is robust and fit for purpose and maintaining consistency with many of these principles is an appropriate counter to the increasing uncertainty generated by the significant changes we foresee across the energy sector.

The recognition that it is not essential to work out the detail of every solution within the next eighteen months will also help to ensure we deliver an appropriately comprehensive DPCR5 framework on time. The price control review can set out a clear strategy and approach enabling companies and regulators to develop new techniques and discover further data as we work through the five years to 2015. We also have the opportunity to develop any more fundamental change to the regulatory framework through the recently announced Review of RPI–X at 20, which could then be developed for implementation as part of DPCR6.

Ofgem's three objectives for the review seem appropriate and balanced, are pitched at the right level for this stage of the debate and tackled in the right order. We agree that the review must focus upon what DNOs should deliver for their customers and for the environment, we then need to understand how the network must be sustainably developed to enable efficient delivery before we finally tackle the question of how this delivery is to be financed and incentivised.

Whilst generally welcoming the Initial Consultation document as a positive and constructive initiation of the price control review debate, we do believe that, in trying to represent all of the possible issues of concern, it contains some statements that could be construed as critical of ENW and other DNOs. We respectfully suggest that Ofgem consider with greater care whether it is appropriate to directly criticize or imply criticism of DNOs in advance of any specific investigations of potential inappropriate activity.

One such example is the implied criticism of the industries connections performance. Several DNOs, including ourselves, have made considerable improvements in this area over the DPCR4 period which seem to go unrecognised. The competitive connections market is starting to have a positive effect for customers in some areas of Great Britain, particularly the North Western regions. Having recently presented Ofgem with a report we commissioned that measures the effectiveness of competition and shows very encouraging signs, we believe that perseverance with the development of competition in connections will lead to further improvements for customers. Ofgem should consider how they might encourage other DNOs to embrace the competitive connections market to the degree demonstrated in the North West and how they might further support the development of the competitive market.

Another area of potentially inappropriate criticism is found in the Environmental chapter of the consultation. Here it seems to be suggested that DNOs are a significant reason for the number of Distributed Generation (DG) connections being lower than Government policy had hoped, although there is no evidence that this is the case. In fact the evidence presented in Appendix Nine of the consultation is misleading in only showing a subset of total connections. ENW have connected 176MW of Distributed Generation in the first three years of DPCR4, considerably closer to the forecasts made than Ofgem suggest.

We face many new challenges in DPCR5 that require Ofgem and the DNOs to work constructively together to develop the best solutions. We are well prepared to engage across the broad spectrum of issues and look forward to working with Ofgem through out DPCR5.

1.2. Environment

We welcome the increased focus that Ofgem have placed on environmental issues and agree that “This price control needs to promote and encourage innovation in the way DNOs invest, operate, maintain and charge for their networks and to be flexible enough to allow the role of the DNOs to change”.

The environmental agenda in particular is driving potentially massive changes to the energy industry, but the exact nature and timing of the changes and their impact on the operations of the DNOs is far from clear. Uncertainty will be a continuing feature under a policy context of seeking market solutions to the extent possible. For example, it is very difficult to forecast the type and volume of DG that will want to connect to specific parts of our networks by 2015 or beyond. This makes it difficult for DNOs to plan effectively for these technologies. There must be sufficient flexibility in the regulatory arrangements to respond to whatever market situation might develop.

We believe that the appropriate way forward is evolution rather than revolution; there is great advantage to be had by maintaining regulatory consistency over the areas which do not need to change, whilst providing a suitable toolkit for response in areas which are still evolving. It is not sensible to fix on one set of “answers” at this stage when the questions themselves are still being developed. We anticipate that the themes of environmental issues and the need for DNO roles to evolve will also form a major strand of the Review of RPI-X at 20.

Various regulatory tools are available to deal with uncertainty. We believe that the most appropriate way forward with regard to the identified environmental issues is the use of incentives, thus providing flexibility of income dependent on the scale of activity faced by each DNO, and also motivating the DNO to respond in an appropriate way.

In determining appropriate incentives to employ, a distinction must be made between the role that the DNOs can play in facilitating activities that have a positive impact on the environment and the DNOs' own direct effects. In this context, the major DNO role as facilitator relates to DG, but could also extend to, for example, heat networks. A DNO's direct effects are defined by its business carbon footprint (including SF_6 emissions and similar effects), which might also be defined to include the carbon embodied within the assets installed by the DNO. It is relatively clear that for those activities that can be measured in terms of carbon effects, the actions that can be facilitated by the DNO are of significantly greater magnitude than the DNO's direct effects. It is appropriate therefore to focus on the DNO role as facilitator, and in particular the key issues of DG and carbon mitigation.

In setting incentives in order to drive DNO behaviours, we need to have a common understanding of what is meant by 'facilitation'. We need to agree where the DNOs are expected to be situated on the following spectrum:

- Remove barriers by being "appropriately reactive" in responding to the requirements of the market. Provide an efficient and economic network service to all customers, both demand and generation
- Be innovative by developing more innovative network and charging solutions (with Ofgem and the DNOs accepting the associated different risk-reward profile)
- Invest proactively by investing in advance of user commitment to enable future connections at lower cost, greater speed or with some other quality benefit (but with the risk of a different outturn use of the network to that predicted).
- Apply positive discrimination by setting a structure of charges which cross-subsidises from demand to generation, to reduce the costs to generators.

Our view is that the appropriate position for DNOs encompasses the first two of the above bullets, but extends only partially into the area of pre-investment.

Incentive schemes that promote performance in areas that customers value and management can control, with logical methodologies and realistic targets and rates are the best way to drive and sustain real behaviour changes. However, the quantification of these issues is not straightforward; even where the "common currency" of carbon equivalence can be established (e.g. for fuel use, losses or SF_6) difficulties can arise relating to both the extraction of robust measurement data and the establishment of consistent calculation processes; for the wider sustainability issues it is more complex still to identify objective measures.

We believe that the following principal mechanisms should be implemented for DPCR5 to facilitate innovation, efficiency and carbon reduction:

- A DG incentive scheme similar to the DPCR4 scheme. We believe that the current DG incentive is fit for purpose in terms of driving behaviours; it was not designed to drive volume. The following improvements could be made:
    - Separate price-controls for demand and generation customers artificially separate these two sets of customers and prevent the DNO

from reducing / increasing charges to reflect impact on the network in a cost-reflective charging framework which would guide generators to the most appropriate parts of the network.
    - The units distributed revenue driver should be removed as it penalises DNOs for behaviour by customers that reduces demand from the network.
    - The issue of connection boundary and Asset Adoption payments should be reviewed as a means to provide a more robust framework for equitable demand and generator charging

- A long-term input-based carbon incentive scheme, targeting individual carbon reduction initiatives such as technical loss reduction, SF6 reduction, use of fuel.
    - There are significant measurement issues that make output based schemes inappropriate.
    - The current losses incentive is not strong enough to drive significant investment per se, although it does change marginal behaviour.
    - The incentive rate should be sized to overcome the cost incentives to avoid investment, but targeted to only encourage appropriate investment
    - We believe the incentive rate should be fixed (possibly indexed to RPI).

- A commitment to build and extend those capabilities that DNOs will require into the future, such as:
    - Extension of the IFI scheme to widen the scope of allowable research and development activities. Areas for future research could include, for example, alternatives to SF_6 in plant.
    - The RPZ scheme should be extended to include innovative ways of managing the network on an ongoing basis and to include demand connections.
    - Funding should be made available to develop the skills that DNOs will need to perform new roles in the future.

It is important to remember that environmental and sustainability issues extend beyond the scope of carbon alone, and concern not only mitigation actions but also adaptation actions. Wider environmental issues over which the DNO has direct influence include visual amenity, fluid filled cables, oil containment and impact of construction. There are also significant activities that relate to adapting to climate change, for example response to severe weather events and flood protection.

In addition to the mechanisms that we suggest above, we believe that consideration should be given within DPCR5 period as to how the role of DNOs should develop, for example:

- There may be a role for DNOs around the interface with transmission beyond this price control, but we believe there would be limited impact during DPCR5 .
- In heat networks, DNOs could become strategic development partners for local authorities, and also provide low-cost long-term investment in community heat assets.
- We suggest that there may be a role for DNOs in promoting network efficiency (combined with energy efficiency where appropriate).

1.3. Customers

At a time when electricity prices have increased at a faster rate than in recent memory, it is important to recognise that the prices paid by customers for energy bills will not be materially affected by the DPCR5 review. Generation, transmission and supply prices contribute to approximately 85% of the electricity bill. Ofgem must be mindful that charges paid to DNOs not only provide customers with high levels of security of supply and stability of service, but also the framework for competition to take place in other parts of the energy chain. Limiting prices in the short term would not only affect network security and service for both current and future customers, but also compromise the DNOs' ability to provide the important facilitation role identified in the consultation document; this would be contrary to Ofgem's duties and should be taken into account in interpreting willingness to pay analysis.

The quality of service incentive is one of the better performing mechanisms in the current price control structure and has facilitated considerable improvements for customers. Customers are enjoying an unprecedented level of service and Ofgem's initial analysis indicates that they are broadly satisfied. This is consistent with our own findings and experience. Whilst the rate of improvement in quality of supply will naturally slow as the main initiatives available to improve performance are implemented across the DNOs, we do not believe that any significant changes are necessary to the basic structure of protections for customers in DPCR5. However, we do have a range of comments on the detail of the quality of supply incentive mechanism. These issues include those addressed by your consultation document, the key ones being target setting, dealing with exceptional events and dealing with severe weather.

We encourage Ofgem to review the disparity of treatment between CI and CML frontier performance to ensure that companies who are outperforming their CI target benefit from the same methodology as is applied to companies outperforming their CML targets. As the overall level of performance improves, one off exceptional events are becoming increasingly important to customers and DNOs. Building upon previous discussions we are keen to finalise a treatment of liabilities associated with forced outages following periods of construction and maintenance activity to ensure that customers do not see the costs of the associated risks crystallised into higher capital unit costs. We also need to avoid the potential for the exceptional events exclusion from QoS scheme to move the incentive from a sensible premise of base performance to total network performance which may drive different, and possibly inappropriate, investment behaviours. We feel that any changes to the exceptional definition, which have the potential to weaken the incentive to improve underlying performance would be a retrograde step and that Ofgem should be careful to avoid this effect.

To build upon the success of the existing regime in improving performance for the majority of customers we agree with Ofgem that it is appropriate to consider how we address performance for customers who are the worst served. Customers who experience the lowest service levels are usually in rural areas served by networks with fewer connected customers. Under the existing framework, companies are unable to build appropriate business cases for economic investment programmes. It is possible that the introduction of a specific allowance would enable DNOs to consider options for network improvements to these groups.

We welcome the level of stakeholder engagement proposed by Ofgem. We have conducted the first industry workshop which was well attended and well received by all of the invited parties. The workshop achieved many of our objectives including identification of appropriate regional stakeholders, provision of education on the electricity distribution business and its impact upon the regional economy and receipt of feedback and contributions that will be valuable in the future. These findings will be incorporated into our future submissions. Stakeholder involvement will allow DNOs to present locally supported, well informed plans to Ofgem. We have always had stakeholder engagement built into investment plans but we recognise there is scope for this to be extended. However, as the DNOs start to address the varying and often opposing priorities of regional stakeholders, we need to exercise our own judgement in the investment planning. It seems appropriate for Ofgem to then assess these plans against customers' willingness to pay as indicated in the consultation document.

1.4. Networks

We believe that there are a number of emergent issues for networks that will result in a change in the balance of investment between 'traditional' and 'non-traditional' areas. In particular, we foresee an increase in non-load investment on the network for reasons other than conventional end-of-life considerations, as the role of the network, the consequential impact it has and the performance expected of it all evolve.

An environmental driver lies behind many of these areas (oil bunding, fluid-filled cables, undergrounding, noise etc.) and we observe that consideration of environmental impact should not be restricted solely to a discussion of climate change and also that, from a networks perspective, climate change adaptation is at least as important as actions to facilitate emissions reduction. This means that careful consideration of flood protection, severe weather resilience and coastal inundation effects will need to be incorporated into DNOs' plans as the assets installed in DPCR5 will be required to cope with the projected climate of the 2050s and beyond.

These changes in the balance of DNO activity, combined with new options for cost modelling that are possible because of improved data availability, mean that it is appropriate for Ofgem to develop new approaches to assessing DNO proposals and modelling expenditure requirements.

We welcome the introduction of the building blocks approach and its promise of clearer definitions and the removal of distortions. In particular, we believe that the new 'Network Costs' grouping will eliminate some of the tortuous definitional issues associated with current reporting, and be better aligned to a prudent whole-life asset management approach. We recognise the attractiveness of equalising the incentive rates across all cost categories within Network Costs in order to avoid perverse incentives but urge caution in developing a framework to achieve this. Equalisation of efficiency rates would almost inevitably have the effect of weakening opex incentives and strengthening capex incentive rates. In a world where opportunities for further opex reductions are increasingly scarce, this may drive DNOs to cut expenditure inappropriately and/ or to underspend capital allowances in an unsustainable manner.

We agree with Ofgem's intention to place more emphasis on DNOs' own forecasts and the incorporation of regional requirements but point out the inevitable diminution in comparability that will result. Ofgem's willingness to review cost modelling approaches and open-mindedness to consider alternatives is essential in ensuring appropriate assessment of regionally-focussed proposals.

The role of history in determining future spend requirements is increasingly unclear and it is important that cost modelling approaches recognise the real drivers of costs such that models are developed with the building block approach to allowances setting in mind. Expenditure assessments should also recognise the diminishing opportunities for further cost savings, particularly in an era of rising input prices.

It is equally important that the most appropriate costs are modelled. All related party margins should be included for modelling and we also urge Ofgem to recognise both the importance of fixed costs in considering efficiencies and the very material "cherry picking" effects that can result from a disaggregated approach to cost analysis.

We welcome Ofgem's acknowledgement of new and continuing areas of uncertainty. In particular, we welcome Ofgem's recognition of the significance of input price increases and strongly support consideration being taken of rising input prices in DPCR5 cost assessments. We also endorse the recognition of the skills issue as a potentially significant medium-term issue for the industry. Our forecasts will endeavour to form a view on all of these aspects, cognisant of the uncertainties due to factors outside our control.

1.5. Financial Issues

We believe that there are important principles to be established at DPCR5 in how financial issues are dealt with that will maximise benefits for consumers and provide the most efficient framework for DNOs to operate in.

The price control needs to provide stability and consistency across many of the key financial assumptions. This should reflect the long-term nature of the DNO assets and is needed to maintain investor confidence in the regulatory regime. It is important, for example, that issues relating to the RAV and regulatory depreciation are dealt with in a consistent manner, avoiding creating unnecessary uncertainty. These issues have longer term implications than the five year price control and any changes need to be assessed over a longer timeframe. We would advocate that they are best considered as part of a more thorough review of the regulatory regime through the Review of RPI-X at 20.

There have been a number of changes since DPCR4 that need to be considered in DPCR5. The recent turmoil in the financial markets has meant that credit investors are becoming more risk adverse and are increasingly requiring strong credit ratings from their utility investments. Yields and credit spreads on A and BBB rated debt show significant increases in recent months and this trend has implications for DPCR5. Setting the WACC at the appropriate level should ensure all DNOs are able to meet financeability tests and maintain their 'investment grade' credit ratings. In the current financial climate where investors are more averse to risk and are increasingly focussed on the need for strong credit ratings, there is a strong argument for Ofgem to explicitly target a long-term stable A3 rating in ratio tests, particularly given the anticipated need of DNOs to raise debt to deliver increasing levels of investment. In short, Ofgem need to take account of the real world financing issues facing the DNOs. The risk profiles of the DNOs have also changed since the last price control review and when compared to other utilities that will require full consideration at DPCR5. We welcome the indication in the consultation that this area will be developed through a separate workstream.

Assessing the appropriate cost of capital is an extremely important element in the price control and in maintaining investor confidence. DNOs operate within different group structures and use different business models. The cost of capital needs to be determined using common generic assumptions for an efficiently managed DNO and a consistent method across price controls to enable innovation in financing structures. Allowed returns at the price control need to be set at least equal to the assessed cost of capital and at a level that ensures that appropriate sources of funding are available to the DNOs. Setting the cost of capital too low will discourage investors from funding the investment required by infrastructure assets.

There has been an increase in Market to Asset Ratios (MARs) for some utility stocks in recent months and the initial consultation questions whether this evidence has implications for the cost of capital. We do not believe this to be the case, since this is a short-term phenomenon and there are significant factors, other than the cost of capital, that justify companies paying premia to RAV.

In the interest of transparency it is important that Ofgem discusses the financial model that will be used to set the price control early in the process with the DNOs. We are already in the position of having to provide forecast BPQ submissions as part of the price control without a full understanding of the implications for revenues and bills post 2010. DNO validation of the model logic once developed would also be helpful in the process.

1.6. Process

We welcome Ofgem's indication that DPCR5 will be a transparent process and their intention to provide longer consultation periods and meetings with interested stakeholders. We support Ofgem's intention to learn from the DPCR4 review and incorporate the best features of that process and the recent GDPCR process. We also welcome the proposed DNO working groups.

We have explained recently to Ofgem representatives how our own stakeholder engagement for DPCR5 will work and our initial workshop for regional stakeholders in Manchester on 10 April was well received by attendees. However it is important to recognise that different stakeholders will be seeking different results from DPCR5 and that greater stakeholder engagement will raise the expectations of some stakeholders. It is imperative that Ofgem and DNOs carefully manage those expectations throughout the process as a failure could lead to dissatisfied stakeholders and a lack of trust in the process for the future.

Ofgem's proposed timetable raises a number of points, in particular:

- There is repetition in March, June, July and August 2009 of "forecast data". We would like to have more clarity on these requests and what these submissions would be intended to achieve. Such clarity would allow for better planning. For example, it would be helpful to understand how these various submissions will interact with the IQI base case assessment.
- We recommend that Ofgem consider the inclusion of a September update, or at the very least publish an update letter between the initial and final proposals. Such a document would allow any developments in thinking to be transparent and would ensure adequate time and due process for correcting the misunderstandings and errors that inevitably creep into a complex and detailed process.

- We welcome the proposal to publish draft licence modifications with the initial proposals as this would remove some potential ambiguity.
- It is essential that Ofgem's financial model is made available much earlier in the price control process than is currently proposed.

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Chapter 2 – Environment

2.1 Introduction

We welcome the increased focus that Ofgem have placed on environmental issues within the Initial Consultation. We agree with Ofgem that the most significant development in the energy sector over the past few years has been the priority placed on tackling climate change, and that there will be increasing emphasis on this issue over the period of the next price control.

The environmental agenda in particular is driving potentially massive changes to the energy industry, but the exact nature and timing of the changes and their impact on the operations of the DNOs is far from clear. Uncertainty will be a continuing feature under a policy context of seeking market solutions to the extent possible. For example, it is very difficult to forecast the type and volume of DG that will want to connect to specific parts of our networks by 2015 or beyond. This makes it difficult for DNOs to plan effectively for these technologies. There must be sufficient flexibility in the regulatory arrangements to respond to whatever market situation might develop.

Against this background, the price control needs to support the industry through transition and be sufficiently flexible to enable to DNOs to respond appropriately as market conditions develop. We believe that the appropriate way forward is evolution rather than revolution; there is great advantage to be had by maintaining regulatory consistency over the areas which do not need to change, whilst providing a suitable toolkit for response in areas which are still evolving. It is not sensible to fix on one set of "answers" at this stage when the questions themselves are still being developed, however we anticipate that the themes of Chapter 2 will also form a major strand of the Review of RPI-X at 20.

We agree fully with the Ofgem's words at 1.16 in the introduction to the Initial Consultation document "This price control needs to promote and encourage innovation in the way DNOs invest, operate, maintain and charge for their networks and to be flexible enough to allow the role of the DNOs to change".

Various regulatory tools are available in order to deal with uncertainty, for instance, revenue drivers, trigger mechanisms, logging up or re-openers. We believe that the most appropriate way forward with regard to the main identified environmental issues is the use of incentives as drivers of revenue, thus providing flexibility of income dependent on the scale of activity faced by each DNO, and also motivating the DNO to respond in an appropriate way.

We will continue to look to maximise opportunities to outperform the regulatory allowance through incentive performance. We are willing to sustain returns by taking risks where we are best placed to manage them.

2.2 DNO Environmental Issues

The consultation paper provides a relatively comprehensive overview of the environmental issues faced by DNOs. Bringing the many issues together gives recognition to the potential of establishing a "common currency" of carbon accounting, allowing comparisons to be made between the benefits of different mitigation actions, impinging on diverse areas such as electrical losses, use of fuel, or SF_6 emissions.

Environmental and sustainability issues extend beyond the scope of carbon alone, and concern not only mitigation actions but also adaptation actions. There are significant activities that relate to adapting to climate change, for example response to severe weather events and flood protection. Wider environmental issues over which the DNO has direct influence include visual amenity and fluid filled cables. Mitigating actions such as oil containment and contaminated land, the impact of construction and noise abatement are addressed in the appendices to this response.

There is clearly a distinction to be made between the role that the DNOs can play in facilitating activities that have a positive impact on the environment and the DNOs' own direct effects. In this context, the major DNO role as facilitator relates to DG, but could also extend to, for example, heat networks. A DNO's direct effects are defined by its business carbon footprint (including SF_6 emissions and similar effects), which might also be defined to include the carbon embodied within the assets installed by the DNO.

The quantification of these issues is not straightforward; even where the "common currency" of carbon equivalence can be established (e.g. for fuel use, losses or SF_6) difficulties can arise relating to both the extraction of robust measurement data and the establishment of consistent calculation processes; for the wider sustainability issues it is more complex still to identify objective measures.

It is relatively clear that for those activities that can be measured in terms of carbon effects, the actions of other parties that can be facilitated by the DNO are of significantly greater magnitude than the DNO's direct effects. ENW data shows the operational business carbon footprint (including SF_6) to be approximately 6% of the equivalent carbon effect relating to losses. Put another way, the connection of a 30MW wind farm would offset our business carbon footprint whereas it would require 500MW to offset the annual losses. It is appropriate therefore to focus on the DNO role as facilitator, and in particular the key issues of DG and, to a lesser extent, losses.

2.3 The DNO Role as Facilitator

DG is clearly an area where the DNO acts as facilitator rather than as a direct driver of activity. The main constraints on development of DG have not been in relation to distribution network cost or access. Instead they have related to issues such as the overall financial viability of DG, terms offered by suppliers buying electricity from DG (related to risk related to electricity trading and the Renewables Obligation), problems with planning permission, and the lack of support for low-carbon heat or CHP.

Similarly, losses can be said to be not entirely within DNO control. The DNO can be said to influence losses but not control the level (since the DNO does not control the level or shape of customer demand)

In setting incentives in order to drive DNO behaviours, we need to have a common understanding of what is meant by 'facilitation'. We need to agree where the DNOs are expected to be situated on the following spectrum:

- Remove barriers
  - By being "appropriately reactive" in responding to the requirements of the market. Provide an efficient and economic network service to all customers, both demand and generation
- Be innovative

    - By developing more innovative network and charging solutions (with Ofgem and the DNOs accepting the associated different risk-reward profile)
- Invest proactively
    - Invest in advance of user commitment to enable future connections at lower cost, greater speed or with some other quality benefit (but with the risk of a different outturn use of the network to that predicted).
- Apply positive discrimination
    - By setting a structure of charges which cross-subsidises from demand to generation, to reduce the costs to generators.

Our view is that the appropriate position for DNOs encompasses the first two of the above bullets, but extends only partially into the area of pre-investment. Thus, we believe that the DG incentive would have to be made significantly more powerful to incentivise the DNOs to make any significant investment in network in advance of user commitment; however, there is scope for investment now in terms of skills training, research and development of technologies and techniques for future use beyond DPCR5.

2.4 The Design of Incentives

Once the desired objectives have been identified, any incentive mechanism needs to pass five tests:

- Is the desired output clearly measurable?
- Is performance controllable by management?
- Is the mechanism suitable for the objective?
- Is the incentive rate reflective of the externalities?
- Is the rate adequate to drive the desired behaviours?

Incentive schemes that promote performance in areas that customers value and management can control, with logical methodologies and realistic targets and rates, are the best way to drive and sustain real behaviour changes.

We believe that the responses to these tests can be broadly categorised as follows, driven mainly by the DNOs' ability to measure and control a particular output:

- DNO has a direct effect
    - Mechanism based on output, if measurable
    - Otherwise, input measures
- DNO influences the ability of others to perform (facilitator)
    - Mechanisms similar to current DG incentive
- DNO cannot act directly now but can build capability for the future
    - Mechanisms similar to IFI
    - Increased flexibility of regulatory framework

2.5 Conclusions

Consideration of the above issues drives out our suggested approach to addressing the topics within the Environment Chapter, as set out below in the following headline points, further elaborated within the Appendices E1 to E12:

2.5.1 DG

See Appendix E2.

The DG incentive is fit for purpose in terms of driving behaviours; it was not designed to drive volume, however:

- We recognise that it is important that progress is made in the development of standards and processes for connections.
- There may be some opportunity for standardising approaches (e.g. application forms, connection agreements) however this needs to be balanced against the benefits of innovative approaches.
- DNOs are already engaged in reviewing the G59/G75 arrangements, and expect to make G59 operate, for smaller generators less than 50kW, in a similar way to G83.
- Given the overall uncertainties over DG market development we are uncertain of the benefits of extending the LTDS below EHV level. However we are willing to consider making all our network data available subject to an appropriate case being made.
- We are not opposed to a single point of access to all DNO LTDS data but this should be through an independent provider of the service, and not one where there is a competitive advantage conveyed to the provider.
- We would welcome a more widely defined IFI scheme.
- We support the extension of RPZ to include innovative ways of managing the network on an ongoing basis and to include demand connections.
- However, the risk/reward stricture of RPZ, being capacity-based, has not brought forward many proposals and consideration should be given to increasing the size of the IFI scheme to include these activities.
- There could be an increased advisory role for DNOs (heat networks, energy efficiency, reactive power, Long Term Development Statements), with a focus placed on network efficiency
- We do not believe that current connection and UoS charges form a significant barrier to the connection of generation; however we are continuing to deliver innovative solutions for DG charging.
- We do not believe that licence conditions are appropriate vehicles for developing charging methodologies, and could not accept conditions being placed on us in areas where the outcome is outside our control.
- The DNOs should be encouraged to innovate and incentivised to invest in skills and techniques to prepare for DPCR6 and beyond. To achieve this, a review is required of related incentives within the regulatory framework:
- The units distributed revenue driver should be removed as it penalises DNOs for behaviour by customers which reduces demand from the network
- For the longer term, the trade-off between capex and opex efficiency incentives should be reviewed to reduce the focus on network solutions with an asset focus; however, due to the fundamental nature of the associated impacts, we suggest that this issue is addressed within the Review of RPI-X at 20.
- Separate price-controls for demand and generation customers artificially separate these two sets of customers and prevent the DNO from reducing / increasing charges to reflect impact on the network in a cost-reflective charging framework which would guide generators to the most appropriate parts of the network.

- The issue of connection boundary and Asset Adoption payments should be reviewed as a means to provide a more robust framework for equitable demand and generator charging

2.5.2 Losses

See Appendix E7.

The current losses incentive is not strong enough to drive significant investment per se, although it does change marginal behaviour. There are also significant data measurement issues, and we believe that the losses incentive is not sustainable in its current form for this reason.

- We believe that these points are best addressed by the introduction of an input-based incentive regime, targeting individual loss reduction initiatives.
- The incentive should be long term in structure.
- We support in principle the approach used at DPCR4 for the calculation of the p/kWh rate to be applied in a losses incentive.
- We believe that the incentives should incorporate a forward looking view of carbon and as a minimum be based on the Shadow Price of Carbon as published by DEFRA.
- We believe the incentive rate should be fixed (possibly indexed to RPI) rather than variable or indexed to electricity prices (with or without a further carbon adjustment).

2.5.3 DNO Role

- There may be a changing role for DNOs around the interface with transmission beyond this price control, but we believe there would be limited impact during DPCR5 (Appendix E2).
- In heat networks, DNOs could become strategic development partners for local authorities, and also provide low-cost long-term investment in community heat assets (Appendix E3).
- We suggest that there is a role for DNOs in promoting network efficiency (combined with energy efficiency where appropriate) (Appendix E4).
- We support the view that the best way of educating customers on the impact of poor power factor is to provide a cost-reflective charging signal (Appendix E6).

2.5.4 Carbon Footprint

See Appendix E12.

Ideally, we would advocate a holistic output-based incentive, based on the "common currency" of carbon accounting, allowing management choices to be made between the various mitigation actions, impinging on diverse areas such as electrical losses, use of fuel or SF_6 emissions. However, we recognise significant data measurement issues in these areas.

- Input based incentives should be considered for the various aspects of carbon emissions. These must be sized to overcome the cost incentives to avoid investment, but targeted to only encourage appropriate investment. It may be possible to aggregate a range of similar mechanisms into one long-term input-based carbon incentive scheme, targeting individual carbon reduction initiatives such as technical loss reduction, SF6 reduction and use of fuel.

- Subject to measurement and consistency issues being overcome, we are supportive of the principle of an incentive for SF_6 leakage if this were structured to mirror the TPCR mechanism. A further suggestion would be to frame the incentive in terms of carbon emissions saved in order to draw equivalence with other carbon incentives or incorporate it into an overarching incentive as mentioned above.
- We have shared with Ofgem our internal report on business carbon footprint, detailing the methodology used and results obtained, and are keen to engage further with Ofgem on the detail of potential incentive schemes.

2.5.5 Non Carbon Issues

See Appendix E11.

Environmental and sustainability issues extend beyond the scope of carbon alone, and concern not only mitigation actions but also adaptation actions.

- We support the development of a more rigorous asset risk management approach to FFCs, and recommend a twin track approach, currently targeting high risk cables against a background of a longer term project for reducing the operational as well as environmental risk posed by FFCs.
- We encourage Ofgem to commit to the continuation of the current scheme for undergrounding for visual amenity, subject to the minor adjustments we suggest, as soon as possible.
- We will be proposing various schemes relating to flood protection, oil containment etc in our capital submission.

Appendix E1 - Answers to specific questions in Environment Chapter

Question 1: Do you think that evolutionary or revolutionary changes are required to the role of the DNOs to ensure that distribution networks remain fit for purpose? If the latter, in what specific areas does this apply?

It is clear that we are entering a period of significant change in terms of how electricity is generated and supplied in the UK. What is less clear is the exact nature and timing of the changes and their impact on the operations of the DNOs. The drivers for change are potentially huge – e.g. the draft European Council target of up to 40% of electricity consumed having to be generated by renewables by 2020, however achievement of this target appears unlikely given current rates of progress.

We support the vision of electricity networks developing to be more active in nature, with significantly more local generation (and storage) being controlled alongside demand by means of intelligent sharing of demand data. This might suggest that revolutionary changes are needed now in order to deliver this vision; however, the path to full active operation is by no means clear, and requires, in our view, a "critical mass" of DG to already be on the system in order that the necessary frameworks and processes can develop.

We do not envisage that full active operation of DNO networks will develop during DPCR5, although we support the taking of controlled steps in this direction. The key issue however is the need to maintain sufficient flexibility in the current price control arrangements, together with the encouragement to innovate, for the role of DNOs to develop appropriately.

This view would be supported by the results of the "Future Network Architectures" report for DTI (2007) which suggests that different DNO networks will need to adapt at different paces based on local DG growth patterns. There is some common functionality in technical requirements but differences in the extent to which they are required, leading over time to hybrid networks mixing traditional and new technologies.

Various regulatory tools are available in order to deal with uncertainty, for instance, revenue drivers, trigger mechanisms, logging up or re-openers. We believe that the most appropriate way forward in this area is the use of incentives as drivers of revenue, thus providing flexibility of income dependent on the scale of activity faced by each DNO, and also motivating the DNO to respond in an appropriate way.

The distinction should be made here between the role that the DNOs can play in facilitating activities that have a positive impact on the environment and the DNOs' own direct effects. Examples of the DNO role as facilitator include DG, metering and registration, heat networks and energy efficiency and also, arguably, losses and reactive power where the DNO can be said to influence but not control the level (since the DNO does not control the level or shape of customer demand). In these cases it should be emphasised that the incentive can influence the actions of the DNO but is limited in its ability to drive the overall activity.

Question 2: Do you think that we have identified the key areas where DNOs can facilitate activities that have a positive impact on the environment?

- We believe that the key environmental drivers on DNOs should be in the areas of DG (see Appendix E2) and losses (see Appendix E7).
- There may be a changing role for DNOs around the interface with transmission beyond this price control, but we believe there would be limited impact during DPCR5 (see Appendix E2).
- In heat networks, DNOs could become strategic development partners for local authorities, and also provide low-cost long-term investment in community heat assets (see Appendix E3).
- We suggest that there is a role for DNOs in promoting network efficiency (combined with energy efficiency where appropriate) (see Appendix E4).
- We support the view that the best way of educating customers on the impact of poor power factor is to provide a cost-reflective charging signal (see Appendix E6).
- Subject to measurement and consistency issues being overcome, we are supportive of the principle of an incentive for SF_6 leakage if this were structured to mirror the TPCR mechanism. A further suggestion would be to frame the incentive in terms of carbon emissions saved in order to draw equivalence with other carbon incentives (see Appendix E8).
- We support the development of a more rigorous asset risk management approach to FFCs, and recommend a twin track approach, currently targeting high risk cables against a background of a longer term project for reducing the operational as well as environmental risk posed by FFCs (see Appendix E9).
- We encourage Ofgem to commit to the continuation of the current scheme for undergrounding for visual amenity, subject to the minor adjustments we suggest, as soon as possible (see Appendix E10).
- We identify possible extensions to the definition of carbon footprint and also certain non-carbon issues having impact on the environment. We also identify a potential issue of interactivity between some issues (e.g. DG and losses) (see Appendix E11).
- We have shared with Ofgem our internal report on business carbon footprint, detailing the methodology used and results obtained, and are keen to engage further with Ofgem on the detail of potential incentive schemes (see Appendix E12).

Question 3: How do we ensure progress is made on the issues identified with the connection of DG? Should progress be facilitated through a working group or should more formal obligations be developed? How do we ensure progress is made during 2009 with:

- **A national standard connection agreement**
- **Reviewing the proportionality of ER G/59 & ER G/75**
- **A national connections process**
- **Reviewing the effectiveness of the LTDS for DG and other users of the network.**

and

Question 5: How can the Long Term Development Statements be made more useful for DG and other users of the network?

The main constraints on development of DG have not been in relation to distribution network cost or access. Instead they have related to issues such as the overall financial viability of DG, terms offered by suppliers buying electricity from DG (related to risk related to electricity trading and the Renewables Obligation), problems with planning permission, and the lack of support for low-carbon heat or CHP. However we make the following points (detailed responses being provided in Appendix E2):

- There may be some opportunity for standardising approaches (e.g. application forms, connection agreements) however this needs to be balanced against the benefits of innovative approaches.
- DNOs are already engaged in reviewing the G59/G75 arrangements, and expect to make G59 operate, for smaller generators less than 50kW, in a similar way to G83.
- Given the overall uncertainties over DG market development we are uncertain of the benefits of extending the LTDS below EHV level. However we are willing to consider making all our network data available subject to an appropriate case being made.
- We are not opposed to a single point of access to all DNO LTDS data but this should be through an independent provider of the service, and not one where there is a competitive advantage conveyed to the provider.
- We would welcome a more widely defined IFI scheme.
- We support the extension of RPZ to include innovative ways of managing the network on an ongoing basis and to include demand connections.
- However, the risk/reward structure of RPZ, being capacity-based, has not brought forward many proposals and consideration should be given to extending IFI to include these activities.
- There could be an increased advisory role for DNOs (Energy efficiency, reactive power, Long Term Development Statements), however
  - It would be inefficient to duplicate the ongoing (i.e. post-connection) role of Suppliers in these areas
  - The focus would be at the time of new connection
  - The focus would be on network efficiency
  - These issues might be partially addressed by a DNO role as strategic development partner for local authorities, as discussed in Appendix E3, Heat Networks.
- We do not believe that current connection and UoS charges form a significant barrier to the connection of generation; however we are continuing to deliver innovative solutions for DG charging.

- We do not believe that licence conditions are appropriate vehicles for developing charging methodologies, and could not accept conditions being placed on us in areas where the outcome is outside our control.

Question 4: Do you agree that DNOs should have stronger financial incentives to reduce their carbon footprint? Do you think that we have identified the key areas where it may be possible to do this?

Overall we agree that DNOs should have stronger financial incentives to reduce both their own carbon footprint and environmental impact, and to facilitate such changes by others. However this broad aim can not be met by a single incentive measure or licence condition.

This question is put more broadly in the Introductory Chapter (1.16): **A key question for this review is how the price control can place incentives on DNOs to control their impact on the environment directly and indirectly.** This acknowledges that the environmental impact of a DNO does not just consist of its own in-year carbon emissions.

Overall the price control needs to:

- Recognise that networks need to adapt to support new patterns of generation and demand – this means incentivising DNOs to innovate and adapt, which in turn requires financial support and acknowledging the risk of failure.
- Recognise that network companies will need to adapt how they operate e.g. services and standards to (many) new generation and demand connections.
- Incentivise efficiency – however the efficiency focus must be on how the networks support the UK's provision of sustainable energy services, rather than just a narrow definition of the most efficient network services; in particular:
    - The environmental impact of the DNO may change when facilitating actions of others e.g. the carbon footprint and losses might rise in some situations due to the connection of low-carbon generation.
    - There needs to be greater flexibility in order to enable non-network solutions to network issues e.g. partnerships with generators and suppliers to control power flows / demand.
- Set incentives in a way that rewards DNO action rather than variability of the measure or actions of others.
- Set long term incentives.
- Enable DNOs to build business cases during DPCR5 to take steps to reduce the environmental impact of specific activities under their control (areas suggested in section E11.1)

Over the longer term, it may be appropriate to take into account external social and environmental costs in the definition of efficiency, establishing a need to:

- factor these external costs into incentives on DNOs e.g. cost of carbon, non-renewable resources, amenity.
- identify the material sustainability issues for the DNOs and how they can be assessed; by continuing to engage with the ongoing work of the DBERR/DWG project on developing tools to assess these impacts

The single most significant carbon footprint issue which DNOs can directly influence is network losses Appendix E7, where we have the following comments:

- The losses incentive has been effective in driving investment in data quality but not significant investment in reducing technical losses given the volatility of the related data.
- It is now appropriate to consider more directed input incentives relating to losses, based on a stronger incentive rate (applicable over a term more appropriate to the nature of the investment), but based on the real trade-offs in carbon costs of the solutions.
- Such incentives could use the "currency" of carbon impact to bring issues such as losses, SF_6 and business carbon footprint to a common base for the purposes of comparing investment benefit.
- The incentive should be long term in structure.
- The incentive should incorporate a forward looking view of carbon and as a minimum be based on the Shadow Price of Carbon as published by DEFRA.
- The incentive rate should be fixed (possibly indexed to RPI) rather than variable or indexed to electricity prices (with or without a further carbon adjustment).

Question 6: Is the current regulatory framework constraining a DNO's ability to facilitate low/zero carbon technologies and if so, what could be done to address this?

We can identify a number of regulatory framework issues which should be addressed. These issues are addressed in more detail in the Commercial section of Appendix E2:

- The units distributed revenue driver directly penalises DNOs for behaviour by customers which reduces demand from the network e.g. energy efficiency, behaviour change, local generation.
- The high power of the opex efficiency incentive means that DNOs will artificially favour network solutions with an asset focus. Thus DNOs have little incentive to act pro-actively in these areas. We support the review of regulatory treatment of payments to generators within the building block approach.
- The Connections and Use of System Charging structure should be reviewed to accommodate the introduction of asset adoption payments. This is a necessary to fully accommodate forward looking UoS charges alongside cost-based connection charges.
- Generators that connected pre-April 2005 and currently do not pay UoS charges should be liable for charges from 2010 without any further phased transition
- Separation of the revenue streams for demand and generation customers artificially separate these two sets of customers and prevent the DNO from reducing / increasing charges to reflect the impact on the network in a cost-reflective charging framework which could guide generators to the most appropriate parts of the network.

Appendix E2 Distributed Generation

E2.1 2.9-2.19 Connections

The DG Incentive

2.9 We invite views on the effectiveness of the current DG incentive.

The introductory paragraphs on the topic of DG connections imply that Ofgem believe that the lack of growth of DG is largely the fault of the DNOs. We refute this entirely and suggest that the real issues constraining DG developments are much more related to the broad development of energy policy and the current economic development of Distributed Energy market.

The main constraints on development of DG have not been in relation to distribution network cost or access. Instead they have related to issues such as the overall financial viability of DG, terms offered by suppliers buying electricity from DG (related to risk related to electricity trading and the Renewables Obligation), problems with planning permission, and the lack of support for low-carbon heat or CHP.

We believe that these issues have been well researched and commented upon in the Ofgem/DTI "Review of Distributed Generation" (May 2007) and also in the Ofgem/DBERR "Distributed Energy – Initial Proposals for More Flexible Market and Licensing Arrangements" (March 2008). It is important that the continuing Ofgem/DBERR work on DE should be sufficiently encompassing so that the growth of DG and DE is appropriately facilitated, and that DNOs will play their part in these changing arrangements. It is probably true that the DE work to date has not had as much input and support from the DNOs as some other aspects of DG in recent years, and we believe that it is appropriate for Ofgem to encourage more involvement in this area from DNOs in the future.

The DG incentive is fit for purpose in terms of driving behaviours; it was not designed to drive volume. External factors have constrained volumes, but not to the extent shown in Appendix 9; this only shows Relevant DG, and excludes DG connected post 2005 under the pre-2005 charging rules. It is also the case that the first two years of the scheme (as reported in Appendix 9) would be expected to show relatively low take-up due to the inevitable time lag involved in bringing schemes through to full commissioning. Our data for the period April 2005 to March 2008 shows 176MW DG connected (of which 62MW is Relevant DG). Our current forecasts for the period to March 2010 show 780MW and 242MW respectively.

The "Future Network Architectures" report (2007) by PB Power and Lower Watts Consulting for DBERR supports the idea that flexibility in price controls must be given to allow DNOs to respond to rapid increases in DG volumes. The structure of the current DG incentive provides an appropriate level of volume flexibility.

Standardised Connection Documentation and Processes

2.12 We see merit in developing a national standard connection agreement, possibly in the form of a schedule to the DCUSA as a bilateral connection agreement template that could accommodate site specific information.

This is a piece of work that is on the ENA COG workplan for 2008/09. It will look to cover all types of connections (except as currently covered by DCUSA) at voltages of LV, HV and EHV and across Demand and Distributed Generation. The work will consider the provision of model form Bilateral Connection Agreement template(s) as part of DCUSA to provide consistency and transparency across LDNOs.

2.14 Notwithstanding the work progressed through the Competition in Connections review, we consider that a standard national process for connection should be developed by DNOs to facilitate further connection of DG.

Ofgem refer to the different connection processes that DNOs have in relation to generators. This is in part a reflection of the different business models that DNOs have for connections in general. Although DNOs might present their requirements in different ways, they all must link back to the Data Registration Code in the Distribution Code. The reason that companies provide their own application forms is to make the data requirements more tailored to the needs of the particular size of installation for their networks. There is probably more that DNOs could do to harmonise their requirements, should this prove to be a real issue.

We too are keen that the DG Connection Guide is kept up to date. However it is important to remember that this guide is under the governance of the Distribution Code Review Panel, and no generator representative, or indeed the Ofgem representative, on the DCRP has indicated any urgency for this work. It is not for the DNOs alone to take this forward. Nevertheless we have succeeded in getting the review of the Guide into the ENA's Engineering Committee's forward workplan; such that resources may be available in the next year should the DCRP agree that this is an appropriate piece of work to prioritise.

<u>Proportionality of G59/G75</u>

2.13 We would strongly encourage the DNOs to address the proportionality of the connection process/requirements set out in ERG/59 and ERG/75 as part of the current review process.

We recognise that there are some legitimate concerns about the costs and complexity of connection arrangements for smaller generators. As the consultation document states, DNOs are now engaged in reviewing these arrangements. DNOs expect to make G59 operate, for smaller generators less than 50kW, just like G83 in that DG equipment can be type tested and the connection process simplified. It must be remembered that the underlying requirements of G59 are those of the ESQCR. Historically ESQCR has been enforced on an absolute basis, rather than a risk assessment basis, and this is one reason why DNOs have had to be cautious in the drafting and application of G59. Ofgem is doubtless aware of the difficulties that DNOs had in getting the then DTI Electrical Inspectorate to allow microgen connected under G83 to install and then inform the DNO, rather than seek advance permission – a requirement the DTI clung to for years.

The current work to review G59 is approaching the stage where the redrafting will be presented for public consultation. Progress does rely on a small group of expert engineers both within the DNOs and the wider community. A particular challenge has been for the working group to find representatives of small generators who have the time and resources to contribute to the work. A consistent theme is the difficulties that smaller generators and their trade bodies have in securing reliable funding from DBERR for their work.

Long Term Development Statements

2.16 (and Question 5) We invite views on how the LTDS could be made more useful for DG and other users of the network.

We monitor the number of users that access our on-line LTDS and it is noted that there are a low number of registered users irrespective of the usefulness of the content.

The LTDS provides details of the EHV networks only. This in its self means that the statement is only of use to larger generators for which an EHV point of connection is appropriate. To extend the range of data in the LTDS to include HV parameters would be of use to smaller generators however there are two significant points that should be considered.

Firstly, the inclusionn of HV data in the LTDS would greatly increase the required effort and expense incurred by DNOs in the preparation of the statement. Secondly, the dynamic nature of the HV network would imply that such a LTDS would have to be more dynamic than the current approach.

Improvements in the accessibility of the existing data would prove useful for DG developers. Data could be provided in an electronic medium that facilitated extraction and export into standard network simulation tools thus allowing DG developers, or their appointed consultants, to undertake their own feasibility studies. Furthermore, if the data were to be presented to a DNO' national standard this would allow national DG developers to further streamline the extraction process.

We are prepared to consider further how such an extension of the existing arrangements could be justified.

Summary Question 2.34. How do we ensure progress is made during 2009 with: Reviewing the effectiveness of the LTDS for DG and other users of the network?

We are aware of the "gridconnection" website that is administered by Econnect. The website provides an interactive LTDS access with the facility to pay for an on-line feasibility study of a prospective DG site. The website provides the DG developer with a real time perspective of the feasibility of his prospective DG connection however we feel the following concerns should be noted:

- The gridconnection website makes a charge for the provision of the feasibility report that is comparable with the charge levied by DNOs for them to undertake the feasibility and provide a firm quotation.
- The DNO has to undertake the feasibility study and levy a charge in order to properly discharge its duty to ensure network compliance with safety and security standards. This will have to be done irrespective of any third party feasibility report.
- The administration of the gridconnection website provides Econnect with a competitive advantage over other similar consultants, ICPs or LDNOs. Advantage is derived through the feasibility report advising developers to contact them for further advice/expertise.

- The feasibility report is based on network data that is updated annually by the DNOs in their LTDSs. From the date of publication the LTDSs are likely to become inaccurate. The DG developer needs to be fully aware of the limitation of the results of the gridconnection feasibility study.

We are not opposed to a single point of access to all DNO LTDS data but this should be through an independent provider. Data provided in a harmonised manner will allow DG developers to undertake their own feasibility study or allow them to commission the most suitable consultant for their requirement.

We do not feel that the quality of the LTDS affects materially the growth potential of DG connections or other connections. The development of a new DG installation incurs a planning period that provides the developer the time to open dialogue with the DNO and commission feasibility studies outside of the normal quotation timescales so that a bespoke solution can be determined to meet the developer's requirements for a minimum cost.

Registered Power Zones

2.19 We invite views on the possible extension of RPZ to include demand connections. We also invite views on whether RPZ should be extended more widely to include innovative ways of managing the network on an ongoing basis.

Ofgem have confirmed in a letter dated 14th Feb 2007 that the IFI scheme would be extended until the end of DPCR5, using a flat pass through rate of 80%. The same letter also confirms that the RPZ scheme would be extended to allow applications for RPZs until 31 March 2010 and connection dates before 31st March 2012. We would support further extension of these arrangements into DPCR5 and beyond, subject to the following comments.

We agree that innovative connection arrangements can bring benefits to all customers, not just DG connections, and that a limitation of the current RPZ scheme is that the proposal must include a generation element in order to gain any reward. There is a more fundamental issue here, in that the risk/reward structure of RPZ, being capacity-based, has not been sufficiently powerful to bring forward many proposals compared with the volume of activity under IFI. Consideration should be given to extending the size and scope of the IFI scheme to include a wider range of activities, including innovative ways of managing the network on an ongoing basis (including demand) and including activities currently addressed by RPZ.

Examples of projects looking at innovative ways of managing the network, and which would currently fall under IFI, are:

- Distribution transformer with online tapchanger
- Superconducting Fault Current Limiter
- Linetracker for use in dynamic rating of overhead lines

Concerns with IFI are as follows:

- We believe that the criteria for eligible schemes should be extended to allow projects on physical security to qualify and also certain areas of environmental concerns. Ofgem are still applying limitations to the schemes that are eligible even after this issue was discussed during the review of the IFI Good Practice Guide - ER G85.

- We would support a review of the 0.5% allowance limit.
- It is not appropriate to require the scheme to be self sustaining in the short term – this is not a sound test of R&D activity.

E2.2 Active Network Management

2.22 Is there sufficient incentive for DNOs to consider non-network solutions before undertaking reinforcement? Are there any particular constraints on the development of demand side management and storage solutions?

There is still much too little DG connected to give a real experience of active network management, even as a demonstrator, let alone as a mass-market approach. In addition the market and contractual framework is not conducive to the generator-DNO relationship that could be needed for Active Management. These issues have been well explored in the Ofgem/DTI "Review of Distributed Generation" (May 2007) and also in the Ofgem/DBERR "Distributed Energy – Initial Proposals for More Flexible Market and Licensing Arrangements" (March 2008).

In relation to non-network reinforcement options, and the possibility of either generation support or demand side contracts there are two critical points to consider:

Firstly, in P2/6 classes C and D when reinforcement is undertaken it is usual to have the objective that following the reinforcement the first circuit outage (FCO) will have no consumer effect, and similarly in Class B the objective is to be able to restore 100% of the group demand within three hours. Although these responses are more than that required by P2/6, they are entirely consistent with the IIS incentives. Whilst a generator might allow compliance with P2/6, there is understandable reluctance to increase the DNO's exposure to the IIS incentive at the same time that operational complexity is increased.

Secondly DNOs are incentivised by the current regulatory arrangements to seek capital solutions rather than operating solutions. A DNO will always look at the contribution to enterprise value of reinforcement options, and is unlikely to choose one that involves generation but does not maximise shareholder returns. This, of course, must be an economic and efficient test that a DNO should apply.

Having made these points, if we had found a clearly beneficial case for generation to support the network, as we have agreed with Ofgem in the past, we would have brought the details of the case to Ofgem to argue for a more sensible regulatory treatment of these costs. In the last three years we have made two specific studies of using DG to support the network. In one case the generation was connected at a higher voltage and the cost of phase shifting transformation was comparable to the network reinforcement costs. In the other, although there is some notional support from two generators into the 33kV demand group, predicted load growth and the expected reduction in output from one of the generators (it is a landfill gas generator) indicates that generation will not be sufficient to cover the contracted demand growth.

Demand side management (DSM) seems to us to be a high cost approach in DNO management terms. Most companies have three overlapping HV networks (132kV, 33kV and 11kV) and ultimately constraints on any of these could be relieved by DSM. However the generally local level of constraints on the 11kV and 33kV systems implies that a local implementation of DSM would be most useful, although the dynamic nature of load and network topology at these voltages could mean that DSM arrangements would need to be flexible in which consumers they applied to. Conversely a 132kV constraint would have a much wider DSM footprint, and a higher system risk.

Customer behaviour is also key to DSM. Currently we are not aware of any work that shows how DSM can be implemented with current domestic consumers for loads other than space and water heating, although we are aware of the research into the use of system frequency as a way of controlling demand. Clearly this could be useful to National Grid, but not to a DNO. There could be opportunities for larger commercial and industrial customers to employ demand side management to aid the DNO – indeed there are some operating examples with existing industrial customers – but these are bespoke arrangements that do not lend themselves to simple extension to a wider customer base.

Again, the lack of a framework for DSM means that a simpler and more cost effective solution is to remove the problem via reinforcement.

Having listed all the difficulties of DSM we are nevertheless open to a review of business practices etc both within DNOs and possibly in Suppliers, to see if there are innovative ways forward.

2.23 We invite views on whether there is clarity on the current regulatory treatment of such costs and what alternative treatments might create a greater incentive on DNOs to consider contracting with generators before undertaking reinforcement.

The regulatory cost treatment needs to be clarified in a way that allows DNOs to assess the cost-benefit of non-network solutions as alternative options to undertaking reinforcement works. Our initial assumption would be that such solutions would involve reduced capex and increased opex costs, and thus be transferring costs into the area where DNOs are most highly incentivised to reduce expenditure.

As a longer term issue, the trade-off between capex and opex efficiency incentives should be reviewed to reduce the focus on network solutions with an asset basis; however, due to the fundamental nature of the associated impacts, we suggest that this issue is addressed within the Review of RPI-X at 20.

DNOs should have the flexibility to invest in DG, demand side management and storage solutions, although could be restricted in their ability to trade in the power markets

2.24. Moves towards DNOs contracting with DG and/or storage to manage constraints may create difficulties where the DNO is part of an ownership group that includes DG and storage as, in effect, the DNO would be making payments to a related party for a service. This may disadvantage DG not affiliated with a DNO. One way of addressing this potential conflict may be to set an incentive for independent DNOs free from generation and storage interests. We invite views on this issue.

Whilst DSM has the potential to contribute to overall system balancing, in terms of its potential to offset local network peak demand, its potential might be limited. Times of system maximum demand on networks serving largely residential customers do not necessarily coincide with widespread use of 'non critical time of use' appliances such as washing machines and dishwashers and certainly not immersion heaters (though cold appliances would qualify). And in any case, it would be important not to simply move the evening peak to a later period and possibly create an even higher peak.

Although the scope for DNOs to contract directly with customers for effective DSM services might be limited, an option that might have greater scope is storage. However, one potential issue with storage is that, like DSM, it has the potential to unbalance the market if independently 'self-despatched' by DNOs. A further issue is that whilst storage might help flatten demand profiles (improve load factor) and hence reduce network variable losses, the AC-DC / DC-AC conversion process is in itself a source of losses.

We do not understand the point you make in 2.24 in relation to independent DNOs. We do agree that the treatment of affiliated parties' costs could well be a distortion, however if the service has been market tested or tendered for, then the margins should not be an issue as they are "efficient" costs.

E2.3 Roles & Responsibilities

Is there a role for DNOs around the interface with transmission? If so, what are the possible developments in this area and how will it interact with DPCR5?

2.28. We invite views on the range of likely developments in this area over the period of DPCR5 and what proposals the industry are currently considering or are likely to consider. If implemented, how would these proposals impact the DNOs? Is there a need to take this into consideration for DPCR5 and if so, how?

The work of TADG over the last two years highlighted the issues around the TO/DNO interface that are being driven by the growth of embedded generation. The TADG work was emphatic that the issues it was considering were non-technical, and related largely to commercial issues associated with charging fairly for the use of the transmission system. We see these issues largely being swept up into the review of the transmission access regime that is now ongoing. We also believe that within DPCR5 this will be an issue that affects DNOs in Scotland to a much greater extent than in England and Wales, not least because of the still inexplicable decisions by Government to class 132kV as Transmission in Scotland.

We intend to play our part in debates that affect us, and we expect that the development of transmission access will introduce new commercial issues for us in our relationship with National Grid. However we do not believe that there will be any material technical changes attendant on these amended arrangements in DPCR5.

E2.4 Commercial

2.31 We remain concerned about the cost-reflectivity of UoS charges to DG and the barrier this might present to the connection of DG.

We have responded separately to Ofgem's consultation paper "Delivering the Electricity Structure of Charges Project". In summary:

- We aim to implement the new DG tariffs and implement new tariffs created from the new EPP (EHV power flow model) methodology from April 2009. This means that we are planning to deliver the changes ahead of the prescribed schedule proposed by Ofgem and in readiness for the challenges that the next price control will bring.

- We do not believe that it is appropriate to deliver a common methodology, particularly as Ofgem do not see this as a requirement in the longer term. It is difficult to see the point in developing a common starting position from which all DNOs are then free to diverge. The DNOs worked extensively together in 2006 and made progress in developing understanding of the issues amongst both DNOs and other stakeholders. However, utilising this shared learning many DNOs recognised that to reflect the individual circumstance faced by their own networks they then needed to use this work to develop their own approaches.
- This approach of collective learning followed by individual innovation will ensure that customers will ultimately benefit from the development of a well thought out approach and a range of new ideas from which a new understanding of best practice will emerge.

We have kept Ofgem updated with our progress and thoughts throughout the Structure of Charges project. Most recently, we have submitted a charging methodology modification proposal specifically aimed at introducing new charges for HV/LV generators.

We recommend that a review of connections boundaries and the use of asset adoption payments should be included within this Price Control Review. We have proposed the introduction of Asset Adoption Payments as this would provide a more robust basis for distinguishing between Connection Charges and ongoing Use of System Charges. This would allow a greater proportion of assets to be funded by users, rather than by connectees, thus facilitating and maximising the sharing of benefit between offsetting generation and demand. To facilitate industry discussion on this point we raised this issue at the Distribution Charging Methodologies Forum.

2.32 How do we address the current lack of cost signals to generators that connected pre-April 2005 that currently do not pay UoS charges?

Discussions under the Structure of Charges Project have long signalled the intention to apply Use of System Charges to all generators from 2010 onwards. Various options for applying transitional arrangements were discussed at ISG; however in our view certain key points drive the response to this issue:

- Even if it accepted that generators have paid for an evergreen right of connection and use of system (a debatable point), this does not mean that their use of system charges would always remain at the same level. Charges for any customer group can change, subject to the appropriate Licence Conditions.
- The issue concerns existing customers (both demand and generation) who have paid contributions towards assets that become chargeable under (forward looking) use of system. In the past this issue was addressed by asset adoption payments/ tariff support. (see comments under 2.31, above)
- The overall level (and potentially sign) of ongoing GDUoS will be driven by the resolution of the "separate revenue drivers" issue (see 2.33, below).
- Our expectation is that, for the majority of our network, a greater proportion of costs would be met by demand rather than generation should the separate DUoS/GDUoS constraint be removed.
- The application of locational charging to EHV networks is likely to drive significant changes (in % terms) in charges for both demand and generation

customers. In principle at least, there is the possibility of either positive or negative charges for both types of customer.

Any change to charging methodology will create winners and losers, in a zero sum game for the DNO. The need for transitional arrangements for both demand and generation customers should be driven by considerations of materiality, and apply to increased costs and benefits alike.

2.33 We invite views on the framework of the current DG incentive and the possible distortions this is creating on more cost reflective charges for DG.

As indicated elsewhere in this response, we believe that the DG incentive itself is fit for purpose against the current market background; however we do advocate the removal of the current restriction which requires DNOs to charge DG based on the revenue provided for through the DG incentive. This restriction does not seem to be appropriate, given:

- The magnitude of the incentive income is driven only by those generators that have connected under the new charging principles since 2005 (Relevant DG) whereas the charges should be applicable to all generators post 2010 (see 2.32 above).
- The calculation of the income is based on the actual costs of reinforcement for the Relevant DG, whereas the UoS charges will seek to recover on a forward looking basis.
- There is no equivalent restriction on the recovery of costs from EHV (as opposed to HV/LV) demand customers, although the PE term is separately identified in the calculation of Allowed Demand Revenue.

We support the removal of the charging restriction, in order that network costs and benefits can be fully shared between the parties that cause them.

Appendix E3 Heat Networks

2.38 With the potential social and environmental benefits created by community energy schemes we consider that a more active role for the DNOs in facilitating the connection of these schemes should be explored. We welcome views in this area.

We acknowledge the benefits of community energy schemes in new developments and regeneration areas, as well as the need for further investment in existing community heating schemes. In established developments, identifying the potential heat users and installing assets for community heating will be more problematic.

From this we can identify two roles for DNOs in facilitating community energy.

- Strategic development partner for local authorities.
- Low-cost long-term investment in community heat assets.

Early engagement with stakeholders suggests to us that there is interest from local authorities in DNOs taking on these types of roles in community heat. However further exploratory work will be required to develop our understanding of this area and how DNOs could facilitate the market.

References to heat in this response are meant to encompass heating, cooling, cogeneration and trigeneration. We suggest that Ofgem should also take this wide definition of achieving low-carbon heat services.

E3.1 Strategic development partner for local authorities

Community energy schemes are most likely to succeed where there is partnership between local authorities and the developer / owner / operator of community heat.

For CHP schemes, DNOs already have a minor stake in any projects via the electrical connection. However this role in providing a connection is too minor for DNOs to be involved at a true partnership level in developing the infrastructure for CHP schemes with community heat. If DNOs are only notified of developments at the stage of application for an electrical connection, this is too late in the project process to influence the development.

Under the recently published supplement to Planning Policy Statement 1 (Planning and Climate Change – December 2007), planning authorities have a new requirement to consider opportunities for fostering decentralised low-carbon energy supply, including 'co-locating potential heat customers and heat suppliers'. Taking a strategic view of the local potential requirements and supplies of electricity and heat will highlight opportunities to provide an overall lower-carbon solution at its minimum cost.

As the local authority or regional development agency has primary knowledge of local needs and development proposals, together with the responsibility for creating the Local Development Framework (LDF) as suggested by PPS1, it is appropriate that this body should keep responsibility for taking this strategic view of energy services, rather than transferring this duty to a DNO.

The local authority may still need technical support to help develop their strategic plans in a number of areas, either in-house or externally e.g. building energy demands, renewable energy supply options and gas networks, as well as wider issues such as water, housing or transport.

Firstly if local authorities wish to take advantage of it, DNOs can be a source of advice to local authorities in developing these strategic plans for energy supplies and networks.

Secondly, via early discussion of strategic plans, DNOs can help identify opportunities to facilitate community energy as a strategic development partner. The benefits may include:

- Early advice on connection options, including use of innovative measures to reduce connection costs using an active network management approach e.g. the DNO may highlight opportunities to contract with a DG/CHP operator to manage power flows
- Identifying opportunities for appropriate timing of work on electrical network assets to reduce overall costs and disruption.
- Improved planning of the electricity network, to reduce costs or timescales.

It should be noted that this important role would have implications for the operational costs of the DNO.

E3.2 Low-cost long-term investment in community heat assets

The strategic advisory role would be enhanced if the DNO could provide input both as a potential provider of the electrical network and the heat assets. This could lead to DNOs providing investment as a strategic partner of the local authority to enable community heat projects to proceed.

There can be a high capital cost involved in community heating and cooling (boilers, chillers, CHP cogeneration units, trigeneration units, pipe network, pumping stations and heat exchangers for hot water, steam or chilled water in addition to any electrical infrastructure). To reduce the cost to final consumers, there is a strong argument for allowing local authorities and developers to choose that this capital investment will be made and financed - instead of at market project finance rates – at the lower cost of capital allowed by the economies of scale of the regulated DNO businesses. Such costs could be added to the DNO's RAV. We would expect that any investment and/or operational (maintenance) costs would be ring-fenced from the existing activities of a DNO, but may perhaps have a common cost of capital.

The rationale for DNO provision of community heat assets is that the viability of district heat community heating with CHP schemes (CH/CHP) is strongly influenced by financing costs and discount rate – see the work quoted in Table 7 of DEFRA's October 2007 publication 'Analysis of the UK Potential for Combined Heat and Power'. Further analysis would be required to quantify the potential benefit of DNO involvement in provision in the aspects of these CH/CHP schemes solely related to heat distribution assets.

Retail of the heat and electricity services, asset operation and fuel supply (fossil fuel, renewables or waste heat) could remain as an open competitively operated activity, with the energy services company paying a capped annual fee for the heat asset. Fuel price risk and direct customer billing relationships do not sit well in the DNO business model. This would not preclude contracting for services which support the electricity network. In some cases however, this may require the ability to store heat or electricity.

The progress of projects would be highly dependent on connections activity and specific plans for new-build, eco-towns or regeneration. It may be appropriate, at least initially, to treat costs via a logging-up mechanism with efficiency criteria. DNOs would not be able to accurately manage or predict the outturn volumes in this market so an information quality incentive would be unsuitable. An alternative would be a scheme similar to the current approach for DG reinforcement which would scale to the size of activity in providing heat distribution networks. Subsequently the heat distribution assets could be adopted by the DNO to manage this asset in the long-term for the community, independent of any change of ownership in heat/CHP generation.

Our early engagement with stakeholders suggests that local authorities would be happier for community heat assets to be owned and operated by regulated DNOs subject to public-service licence obligations and a regulated income, than for their residents to be connected to networks operated by other private companies. The stakeholders would also benefit from having a single point of contact for management of the heat and electricity network.

Appendix E4 Energy Efficiency

2.41. The role of engaging with customers on energy efficiency is currently largely considered a role of energy suppliers. Can DNOs contribute to providing energy efficiency advice to customers? Should DNOs be incentivised to take a more proactive role with end consumers on energy efficiency, and if so how?

We recognise the importance of reducing customer demand in meeting UK energy policy objectives and particularly reducing carbon emissions.

Whilst DNOs could deliver generic energy efficiency advice to customers we would question whether we are best placed within the energy industry to provide this service. We believe that it in many instances promotion of energy efficiency lies best with energy suppliers as they have more routine communication with customers.

We suggest that it is sensible to focus attention on activities that allow DNOs to promote network efficiency (combined with energy efficiency where appropriate) and in particular the following:

- Ensuring that the DG incentive continues to encourage DNOs to connect DG, possibly with particular emphasis on promoting connection of micro-generation.
- Ensuring that DNOs retain the ability to develop innovative charging structures for both DUoS and connections charges that promote the efficient use of the distribution network.
- Ensuring that DNOs have access to the data from smart metering, to allow innovative tariff structures to be developed that can promote the real-time efficiency of network usage.

2.42. We seek views on the extent to which a kWh revenue driver is still appropriate.

A kWh revenue driver is inappropriate because the principal drivers of DNO costs are peak power flows and fault levels rather than energy delivered from the network.

Currently the unit revenue driver on DNO income would discourage DNOs from exploring ways to actively facilitate low-carbon CHP or other DG projects at a demand site. This is because many of these projects reduce income from the demand for electrical energy from the network without a similar reduction in network costs (related to capacity for peak power flows and fault levels). Thus a removal of the kWh revenue driver would remove this perverse incentive.

As an example, consider the case of connection of a 1kW small generator (SSEG) in 2005/06 at a domestic site, which reduces annual electricity demand from the network by 1500 kWh/yr for the rest of DPCR4. On a single rate tariff, the income reduction from the units driver is roughly double the allowed income increase from the DG incentive. The DNO will also incur a small administrative cost related to connection of the generator. Thus the overall financial impact on the DNO is negative.

Appendix E5 Metering

2.47. We do not consider that regulatory arrangements should be designed to encourage DNOs to play a role in delivering smart meters: the extent of their involvement should be governed rather by their success in competing against other meter operators to provide this service to energy suppliers.

At the 2004 price review Ofgem removed a value for metering assets from the distribution RAV, thereby assuming that this residual asset value would be recovered in the competitive metering market. When these assets first entered the RAV it was assumed that they would be fully funded through subsequent distribution price controls. Removing the assets in this way creates uncertainty and is likely to lead to asset stranding. This is of particular concern as accelerated removal of metering assets as a result of the roll-out of smart meters increases the risk of asset stranding. We urge Ofgem to consider the treatment of legacy MAP, and in particular potential stranding of MAP assets as a consequence of the roll-out of smart metering, as part of this price control review.

Appendix E6 Reactive power

2.47 Is there more that DNOs should be doing to encourage efficient use of their network or are the current measures appropriate? For instance is there scope for DNOs to do more to educate their customers on the impact of poor power factor?

DNOs have an number of options to promote the efficient use of their networks, including encouraging off-peak use, encouraging connection in areas of their network that have spare capacity and promoting appropriate power factor limits and correction equipment.

As one of these options, reactive power charging is important to provide a strong pricing signal to those parties who utilise their supply at a level which is worse than a 0.95 Power Factor. We support the view that the best way of educating customers on the impact of poor power factor is to provide a cost-reflective charging signal.

These options are reliant on a DNO's ability to provide appropriate price signals to encourage efficient use of networks by consumers. Of fundamental importance is the retention of DNOs' commercial freedom to develop appropriate, innovative charging structures.

Appendix E7 Losses

2.53 We invite views on how much of the reduction in losses can be attributed to actions by the DNOs through technical improvements to the distribution network.

The current losses incentive is not strong enough to drive significant investment per se, although it does change marginal behaviour. It is however worth making sure that overall flows in settlements are as accurate as possible and losses are not improperly inflated due to systematic errors. It has also driven us to initiate CP1189 to change to Elexon's systems for SVA metering to recognise loss factors associated with generation where the generation dominates and increase losses. Clearly these system changes do not really address actual loss reductions, but they do help to ensure accurate recording, and in the case of CP1189 should send some slightly more appropriate economic signals.

When looked at over a five year period, any investment we could make specifically to reduce losses is likely to have a very small impact and, since the uncertainties caused by customer behaviour are also significant, we do not have a high certainty of seeing a return on the investment - even assuming we could measure it properly.

However, over a number of years there have been several initiatives regarding losses and their optimisation, including:

- Optimising the positioning of HV open points for losses (carried out in the early 1990s, prior to the introduction of the incentive)
- Subsequently, the network has been optimised operationally with the objective of minimising CI/CMLs (although sub-optimal from a losses perspective). Planning policy now calls for the positioning of open points to reflect various considerations including load, operational switching, volt drop, losses, with no particular priority being afforded to losses.
- During DPCR4 we have evaluated the value of using low loss transformers based on the current incentive rates and manufacturers prices. Low loss transformers have generally been used throughout this period.

It would be extremely difficult to estimate the worth of all of the above with any accuracy; however, as an indication of the order of magnitude, we believe that the current review of settlements data quality has greater potential impact on the overall reported losses numbers than the summed effects of these various initiatives.

We have also investigated a number of other initiatives which have not shown sufficient cost benefit over risk to be implemented:

- A network design based on a radial network and use of larger size cables as a standard single size has been evaluated.
- A project has been undertaken to calculate the cost/benefit of switching out primary or BSP transformers at periods of low load.
- Analysis has been completed to quantify the effect of shifting a portion of peak demand using DSM.

2.54 (Substation own use) One way to address this would be to take account of unmetered supply at substations in calculating the losses incentive. We would welcome views on this issue.

If the losses incentive were to continue in its current form (which we do not support), there should be a continuation of the adjustment of sales to account for unmetered own use so that these units would not be treated as losses. If a change to the reporting methodology were made, this would also have to be reflected into the associated targets.

2.55 Although we note concerns over the effects of fluctuations in the settlement data we expect that over the long run the impact of technical loss reduction will become evident and that the current arrangement does provide an incentive to invest or improve network operation to reduce technical losses.

We agree that the impact of significant technical interventions might be visible over a "long run" of similar order to the life of the investment in this instance, say 20 years. However, in order for investment to be made the business case must be based on the life of the incentive itself, which is currently five years. We favour the introduction of longer term incentives in order to address this issue.

2.56 (Network Models) While this is technically feasible it would prove to be a very complex task and dependent on the quality of the network data, customer load profiles, metering data all of which would have the potential to introduce error.

We agree with Ofgem's analysis of this option. A key issue is the non-linearity of losses, meaning that accurate data is required by time of day. Furthermore, a significant proportion of overall losses occur at the LV level, where generic models would be required.

An example of a technical network model for loss assessment would be the work commissioned by DBERR on behalf of Work Stream 5 (WS5) of the Technical Steering Group (TSG) to the Distributed Generation Co-ordinating Group (DGCG). In this project, a unique modelling and assessment tool was developed which was used to investigate the impacts of distributed generation upon network losses. The tool uses load profile information and calculates the annual losses for "typical" networks (132kV network down to the consumer's cutout) with varying levels of distributed generation. A cloning approach is used to build up a picture for a whole DNO from the individual network results.

The tool was used to draw overall conclusions regarding the losses impact of DG on typical "urban" and "rural" networks; however the model would require significant extension and calibration in order to give a sufficiently accurate calculation of actual losses for a DNO network. Furthermore, even with a suitable model, the input metering and profile data would suffer from the volatility issues identified elsewhere in this response.

2.57. Another option is for DNOs to be encouraged to reduce technical losses by funding for specific loss reduction programmes involving low loss equipment and/or network design and operation, ie discrete funding for specific actions. This input based approach has the risk of rewarding investment made rather than the desired outcome achieved.

We believe that strong consideration should be given to moving away from overall output measures towards more targeted input initiatives. This might address the data volatility issues attaching to overall loss measures, and focus more on real loss reductions. There would need to be a range of measures of this type. Although this reduces DNO freedom in how to manage their position, it is more appropriate in situations where measurability of the output is such an issue. These measures could include:

- Low loss transformers
- Introduction of minimum technical standards for plant
- Targeted replacement of mechanical meters
- Audit inventories of unmetered supplies
- Reducing substation electricity
- Targeting illegal abstraction

2.58. It may also be important to consider the current incentives on suppliers to reduce non-technical losses as well as increasing the level of interaction between suppliers and DNOs to improve information flows on losses.

Illegal abstraction is an important contributor to non-technical losses, and increasingly so as the propensity to abstract illegally increases alongside rises in retail prices.

We believe that the current supply market arrangements only give suppliers a weak incentive to deal with illegal abstraction of electricity. Some suppliers are proactive in this area, producing policies for revenue protection providers to implement, and this activity should be encouraged. A standard consistent policy for all suppliers would be better still, and could be a matter for the ERA and ENA to consider collectively.

It should be possible to produce a scheme which ensures suppliers who do undertake revenue protection activities for the benefit of everyone are not penalised. All suppliers who discover illegal abstraction should be encouraged to record the stolen units in the settlement process, By doing this, however, suppliers may be unable to recover the costs from the responsible customer. It may be appropriate for these unrecoverable costs to be paid by the distributor, who would then recover them through use of system charges via the pass through mechanism in the price control.

With regard to data flows between suppliers and DNOs, Elexon are investigating whether illegal abstractions are being correctly entered back in settlements by the suppliers' agent. We support Elexon's initiative here, hoping for an expeditious conclusion.

2.59 It is essential that any incentive is valued against recognised external benchmarks (such as the shadow price of carbon) and as detailed throughout this chapter we seek views on an appropriate benchmark value. We also invite views on whether the incentive rate should be fixed, variable, or indexed to a recognised index of wholesale electricity prices (with or without a further carbon adjustment) given the potential uncertainty in forward prices for energy and the cost of carbon.

In DPCR4, Ofgem used a methodology to establish a rate for the losses incentive. This rate had four main components:

- the cost of purchasing lost units of electricity;
- the cost of using the transmission system to transport the additional units to distribution system entry points; and
- the cost of providing, operating, and maintaining additional distribution assets to transport the additional units.
- the environmental cost of producing and transporting additional units of energy i.e. the environmental costs of the three items above.

The Shadow Price of Carbon (SPC) as published by DEFRA is recognised as the standard value to use in UK policy making when considering the environmental and social costs of carbon. However carbon impacts are not the only environmental or cost effects e.g. local air pollution dependent on electricity source, visual amenity and use of non-renewable resources. Thus the SPC might be considered as a minimum value to take into account for environmental impact.

The SPC is defined in units of £/tC and this price changes annually. The value of £28.50/MWh stated in paragraph 2.59 includes an implicit assumption about the relationship between MWh of electricity and the associated carbon content. Both SPC and annual average carbon/MWh are changing continually, the latter dependent on the prevailing generation mix, generation outages and network constraints. Furthermore, not all losses are associated with equal carbon emissions, dependent on the time of day in which they occur.

However, it is important that there are clear long term cost signals for investment decisions which have a 20 year timeframe. Furthermore, short term price volatility is not a risk that DNOs are well placed to manage. Against this background it would more appropriate to assess and define a forward view of costs (as a schedule if necessary) against which the DNO could assess the loss reduction potential of particular input measures.

In summary:

- We support in principle the approach used at DPCR4 for the calculation of the rate to be applied in a losses incentive.
- We believe that the incentives should incorporate a forward looking view of carbon and as a minimum be based on the Shadow Price of Carbon as published by DEFRA.
- We believe the incentive rate should be fixed (possibly indexed to RPI) rather than variable or indexed to electricity prices (with or without a further carbon adjustment).

2.60. Given the significant environmental impact from network losses, we are committed to encouraging the DNOs to continue to find ways to improve their performance. We welcome views on the different options discussed above.

We agree that losses are a significant contributor to carbon emissions, which DNOs can influence but not fully control. We believe that incentives for action should be put in place, but any incentive mechanism needs to pass five tests:

- Is the desired output clearly measurable?
- Is performance controllable by management?
- Is the mechanism suitable for the objective?
- Is the incentive rate reflective of the externalities?
- Is the rate adequate to drive the desired behaviours?

We believe that these points are best answered by the introduction of an input-based incentive regime, targeting individual loss reduction initiatives.

Appendix E8 Sulphur Hexafluoride (SF6)

2.66. The scope of the transmission incentive on SF_6 emissions is set out in the TPCR Final Proposals. We welcome views from respondents as to whether a similar scheme is required for electricity DNOs and whether there are any reasons why this should differ from the transmission scheme.

We are supportive of the principle of an incentive for SF_6 leakage in DPCR5 if this were structured to mirror the TPCR mechanism. However in order to develop such a mechanism, work needs to be carried out to develop improved reporting mechanisms and data consistency checks for SF_6 losses to ensure that consistent targets are set across all DNOs. A further suggestion would be to frame the incentive in terms of carbon emissions saved in order to draw equivalence with other carbon incentives.

We note that there is potentially significant capital expenditure required if DNO measurement arrangements are to be brought to a similar standard to those of NGT. It is unlikely that this level of expenditure would be warranted and therefore alternative measurement arrangements will need to be agreed.

We suggest that the issue of alternatives to SF_6 for switchgear insulation should be an appropriate field of research for inclusion under IFI.

Appendix E9 Fluid Filled Cables

2.72. Based on the data available, we invite views on whether this is an area where an incentive should be focussed noting that data specific for sensitive areas, which is one of the main concerns regarding fluid-filled cables, is currently not reported to Ofgem by the DNOs.

We have developed a risk-based approach based on the replacement of some of our fluid filled cables (FFCs) in areas where leaks have the highest impact. However, due to the age and condition of FFC this is unlikely to reduce the volume of fluid lost; for example, from your figures a 32% reduction in transmission FFC has reduced fluid loss by 3%. We have also had a significant programme of joint refurbishment of approx £800k pa and a replacement programme and yet are currently unable to reduce leaks below the current level – not least because of third party damages to FFC assets. We recommend a twin track approach of replacing high risk FFC over a small number of price review periods with a longer term project for reducing the overall operational as well as environmental risk posed by FFCs. This approach has been influenced by the increasing environmental pressures to reduce fluid loss and also concerns over the future operability of these cables, particularly the risks posed by the extended repair times (i.e. weeks in some cases) for these cables, as obsolete technology compared with modern cable types.

Appendix E10 Undergrounding

2.77 Should the scheme continue for DPCR5? Should undergrounding be fully funded by the scheme or is it appropriate for DNOs to contribute funds? Should allowances be based on a uniform proportion across all DNOs as now, or is it appropriate to allow some flexibility in these amounts depending on stakeholder buy-in and DNOs' business plans?

ENW has supported the undergrounding scheme since its inception, believing that it can provide significant local environmental improvements in designated areas that would not otherwise be possible. We also believe that it provides a model for public/private partnership working which can facilitate other joint work in the region.

Our experience of the scheme has been that the timescale for identification, assessment, design and implementation of projects can be many years, and hence we welcome Ofgem's intention to clarify the future status of the scheme later this year, in advance of the main price review discussions.

As such, we are only now seeing significant construction work in a number of areas. Part of the reason for the long timescales involved is the rate of scheme attrition, i.e. projects considered non-viable for technical, access, landowner, operational, cost or resource reasons.

As of May 2008, ENW had received proposals for undergrounding 172km of overhead lines (5% of total overhead network in eligible area). Of this total,

- 1km has been undergrounded
- 3km is about to start construction
- 81km is in detailed design or wayleave negotiation
- 35km are on hold due to lack of funding
- 52km have been rejected due to failure to meet one or other constraint

Of the rejected lengths, 29km was due to cost cap constraints, 21km due to the young age of the assets proposed for replacement and 1km due to landowner issues.

Prime amongst these is the issue of the cost caps – by imposing an arbitrary limit on recoverable costs, the scheme becomes self-selecting in that only the cheaper (i.e. 'cleaner') lines have been selected, to the detriment of more expensive but arguably more scenically valuable options. To date, we have been reluctant to supplement these funds with monies diverted from the main capital programme for fear of falling foul of Ofgem's 'demonstrably in addition to existing programme' rule and consequent risk of non-recovery.

In terms of the structure of the scheme going forward, we appreciate that customer willingness-to-pay needs to be taken into account, however we would also point out that Ofgem are encouraging the input of local stakeholders, who may have differing views. As such, we believe that a continuation of the scheme in roughly its current form and at its current level would be an appropriately balanced proposal. However, to address some of the shortcomings of the present scheme, we suggest the following changes:

- That the scheme be applicable to proposals from the designated area representative bodies, even if the location of the proposals falls outside of the designated area itself (but can be seen from it, for example).

- That, the above notwithstanding, the scheme is not extended to non-designated areas.
- That Ofgem define or remove the 'demonstrably in addition to existing programme' rule, such that DNOs can top-up available funding where appropriate without fear of log-down.
- That the overall entitlement is set at an equivalent level to DPCR5, i.e. 1.5% of eligible network but that the costings used to derive the available allowance are updated to take account of the realistic practical costs of undertaking this type of work.
- That once the allowance is set, Ofgem consider removing the cost caps entirely. In line with the emphasis on greater stakeholder involvement, we suggest that the available allowance can be pro-rated across designated areas. It is then for the representatives of those areas to decide how to invest the allowance, informed by costings from the DNO. If they decide to invest in relatively expensive but scenically very valuable schemes, then they would be allowed to do so.

That Ofgem clarify the treatment of projects which have been initiated and commenced under the DPCR4 scheme but whose actual completion falls in DPCR5. We propose that committed projects at 31st March 2010 are funded from the DPCR4 allowance, and that any balance remaining following these deductions is forfeited by the DNO.

We concur with Ofgem that the scheme should remain voluntary and that it should not be applied to new overhead lines which remain a technically viable solution and are planned in accordance with strict planning criteria. We agree that to do otherwise risks distorting the connections market through not providing least cost viable connection solutions.

We also note that, in the context of some of the other potential developments referred to in this Chapter, underground solutions carry an increased carbon footprint in terms of carbon embodied within the assets relative to their overhead line equivalents. This issue may merit further discussion, and is indicative of the fact that environmental and sustainability issues extend beyond the scope of carbon alone.

Appendix E11 Other Activities

2.78. We invite views on what other activities could be considered as an activity associated with the operation of a DNO's network that impacts their carbon footprint.

Question 2 Do you think we have identified the key areas where DNOs can facilitate activities that have a positive impact on the environment?

It is possible to set the boundary conditions in the definition of carbon footprint more widely than indicated within Chapter 2. In particular, as noted below in "Activities having an Impact on Carbon Footprint", the definition could be extended to include a greater range of transportation activities and also the embodied carbon within assets.

It should also be recognised however that the actions of the DNO in facilitating competitive low carbon solutions might increase the footprint of the DNO itself. An example of this is the treatment under the current losses incentive of DG that adds to network losses. This principle will need to be taken into account in the design of new incentives, and requires a holistic approach to incentive setting.

Environmental and sustainability issues extend beyond the scope of carbon alone, and concern not only mitigation actions but also adaptation actions. Wider environmental issues over which the DNO has direct influence include visual amenity and fluid filled cables, both covered previously. There are also significant activities that relate to adapting to climate change, for example response to severe weather events (covered in the Networks Chapter) and Flood Defence (below). Non-carbon mitigating actions addressed below include Oil Containment, Contaminated Land and Noise Abatement.

E11.1 Activities having an Impact on Carbon Footprint

Other activities associated with the operation of a DNOs network that have a direct carbon impact include: fossil fuelled mobile generation (as mentioned in 2.78), HFC emissions from air conditioning systems and the transport of assets, equipment and materials carried out during operating, upgrading and maintaining the network. As an example, it would be possible to consider the carbon emissions relating to the transportation of a transformer from site of manufacture to site of use as part of a DNO's carbon footprint.

As well as direct carbon emissions associated with a DNO's network operation there is also embodied carbon present in the assets installed on the network. This embodied carbon results from energy used in the extraction and manufacture of the basic materials (such as steel, copper or plastic) that an asset is constructed from. As user of such assets a DNO could account for the embodied carbon present in them as indirect emissions within its carbon footprint.

We have put significant effort into quantifying these effects using the latest environmental models available from the Environment Agency. This could be developed to allow, during the development phase of projects, assessment of the relativity between the lowest whole life financial cost solutions to lowest whole life carbon cost.

It is possible to extend this approach to take non-carbon environmental impacts into account, providing a more holistic view of sustainable network development (which may not always be the lowest carbon solution); however, given the difficulties of measurement of these issues and the current starting position, it is probably sensible to defer such developments to a later stage.

E11.2 Flood Defence (permanent / demountable or temporary)

The DNOs have been working together as part of the ENA Resilience to Flooding Task Force and have produced a report to support the Pitt Review that has been reported to the Energy Minister. This produced a cost range of between £100M & £400M to protect DNO Grid & Primary Substations and Transmission substations in Great Britain.

We are carrying out a further detailed review which has identified around 80 at-risk Grid and Primary substations which are within flood plains, and are following the nationally agreed process for further assessing the risk at these sites. We are in the process of completing existing flood protection work at 22 sites which were identified as at-risk based on information provided by the EA in 2005 and following the Carlisle floods. It is likely that a number of additional sites will need permanent protection and it is proposed that these be included in the DPCR5 capital submission

E11.3 Oil Containment of Transformers and Contaminated Land

The risk to the environment of oil leaks can be managed by bunding but also by the provision of flood defences; therefore any programme of oil containment or flood protection would reduce the risk impact on the environment of oil leaks.

In the mid 1990s we undertook a programme of retro-bunding of Grid & Primary transformers. This programme was based on a 'Controlled Water Survey' carried out to risk assess the impact of oil leaks on the environment and took account of the proximity to water courses, aquifers and the local geology.

More recently we have carried out a contaminated land risk assessment which has identified a number of sites where further retro-bunding can be justified to manage the risk of oil leaks. This desktop study indicates that 4% of our sites are high risk, 46% moderate risk, 38% low to moderate risk and 12% low risk. To further reduce our risk profile we propose to install oil containment to a number of Grid & Primary transformers. This approach would mitigate future leaks but there is also a need to carry out some site investigations at high risk sites which is likely to lead to the need for some land remediation. The highest at-risk sites tend to be those which were previously gas works or power stations where the land contamination is due to their historic use.

E11.4 Noise Abatement

In the late 1990s we carried out noise surveys at the majority of our Grid & Primary substations; however we have since followed a reactive approach, only dealing with sites where an official complaint has been received from a Local Authority. We are now considering the adoption of a risk based approach, targeting a relatively small number of transformers, where the transformer noise above background noise is more likely to cause a complaint. This would allow justified complaints received from customers to be actioned without causing the customers to have to resort to complaining to the Local Authority.

For all new construction the likely impact of noise is assessed and, where justified, acoustic enclosures or low noise transformers installed. These solutions have an impact on the average unit costs for new work.

Appendix E12 DNO Business Carbon Footprint

2.79 One issue for DPCR5 is whether incentives should be placed on DNOs to reduce the direct carbon footprint of their businesses.

Losses apart, an incentive on reducing the carbon footprint of a DNOs business operation may be premature as the first challenge is to reliably measure the carbon footprint. As these measurements are relatively new and data availability and breakdown is not homogeneous across DNOs any measured "reductions" could be due to data cleansing and improvement of measurement methodologies rather than actual reduction of GHG emissions.

At this stage effort should be concentrated on defining a specific methodology to ensure each DNO measures the same emissions in the same way and also detail the calculation of the carbon footprint baseline. The organisational boundaries of any such calculation (such as the inclusion of work carried out by subcontractors on the network) would have to be clearly defined.

It may be appropriate to separate out specific aspects of the overall footprint (losses could be one such example) and apply input-based incentives to these particular issues. It should also be considered whether it is appropriate to consider the potential offsetting impact of the increased embodied carbon associated with assets installed in order to reduce the direct operational carbon footprint.

2.82 We are keen to understand the existing measures of carbon footprint being used by DNOs and, where appropriate, to reward companies that are already active in measuring and reducing their carbon footprint through any incentive scheme.

Our approach to accounting for emissions is detailed in our carbon footprint report and is based upon the guidelines set out in "The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard" from the World Resources Institute. We have used an operational control approach to define organisational boundaries and operational boundaries are also detailed within the report.

We have shared with Ofgem our internal carbon footprint report, detailing the methodology used and results obtained, and are keen to engage further with Ofgem on the detail of potential incentive schemes.

2.84 The discussion above suggests that data availability is not homogeneous across DNOs; thus, estimates of the carbon baseline may not be based on solid empirical evidence in some cases. One way of alleviating this shortcoming would be to implement a discretionary reward scheme in the short-term. This might encourage some DNOs to lead on carbon footprint issues.

The key issue to address in order to establish a DNO's own carbon footprint is the question of where the measurement boundaries should be set, particularly where activities are outsourced. A common DNO objective would require the data reporting boundaries to be agreed, taking into account:

- Differing business separation models
- Contracted out activities
- Operating territories

- The conversion factors to be employed

We agree that a standard reporting methodology which details the emissions to be accounted for and reported by each DNO set by Ofgem would create consistency across the DNOs. Methodologies for carbon baseline and carbon footprint calculations will have to be the same for all DNOs to ensure a level playing field. The standardisation of methodologies will need input from the DNOs and Ofgem to produce a suitable solution which can be defined so that all DNOs are able to accurately measure their carbon footprints, with emissions to be included in this measurement made clear and unambiguous – clearly defined operational and organisational boundaries are required.

Other emissions identified by individual DNOs outside the scope of the reporting methodology could be reported separately and credit for carrying out this extra work given by Ofgem. We see a role for IFI in providing funding for such work (rather than a discretionary reward scheme), being an appropriate mechanism for research work that will eventually be used by DNOs collectively. We also believe that the greater certainty of funding associated with IFI is more likely to drive investment in this area.

2.85 Ofgem is intending to host a workshop with the DNOs and other network operators to gain a greater understanding of the work currently being undertaken by the network companies to understand their own carbon footprint, to identify the alternative measures in building up a DNOs carbon footprint and to identify which measures are the most appropriate. While at least some of the DNOs have been collecting data on their carbon footprint, it may be that the measures that are being utilised are not consistent or there might be gaps as well as issues on the allocations of emissions among businesses of the same corporate group. We invite views on these issues.

We agree that consistent methodologies are required and that these might be developed along similar lines to the earlier IIP scheme. A first step would be to convene a series of Ofgem/DNO workshops in order to work up some initial proposals for carbon measurement.

Chapter 3 - Customer

3.1 Introduction

We recognise the value to the business of good customer service; we believe that good customer service makes good business sense. The most efficient regulated companies traditionally perform well on customer service performance indicators. Successive surveys have shown that urban customers generally enjoy high levels of service with most never losing their supply of electricity suggesting that the existing arrangements are delivering the service that customers value.

At a time where electricity supply prices have increased at a faster rate than in recent memory, it is important to recognise that the prices paid by customers for energy bills will not be materially affected by the DPCR5 review. Generation, transmission and supply prices contribute to approximately 85% of the electricity bill. Whilst the price/service package may now be broadly acceptable to customers, the current economic position is influencing responses. Ofgem must be mindful that charges paid to DNOs allow competition to take place in other parts of the energy chain and customers receive high levels of security of supply and stability of service. Compromising both the performance for future customers and network security to limit prices in the short term would be contrary to Ofgem's wider network sustainability objective.

DNOs respond well to incentives in areas where they can control their performance. The quality of service incentive is one of the better performing mechanisms. It provides an adequate incentive for DNOs to improve upon base service levels and to prioritise some service measures ahead of pure cost cutting. Therefore, the existing measures need to stay in place to maintain recent service improvements. We agree with Ofgem's suggestion in paragraph 3.3 that it is not appropriate at this stage to raise the bar on current standards and incentives. However, Ofgem and customers must recognise that the DNOs are constrained by the relative strength of the current incentive mechanism. Under the present rate, we are finding it increasingly difficult to build commercially viable business cases to carry out any additional customer service improvements in DPCR5. This will result in a slower rate of service improvement through the next price control.

The present regime incentivises DNOs to improve average customer performance. Whilst we accept that we must addres the needs of customers who receive performance significantly below the average, Ofgem should recognise the benefit of targeting average performance under normal conditions. Any discussions of separate worst served customer, short duration interruptions or total duration mechanisms need to be held with this overarching objective in mind.

We welcome the level of stakeholder engagement proposed by Ofgem. As Ofgem is aware, we have conducted the first industry workshop which was well received by all of the invited parties. Stakeholder engagement will allow DNOs to present locally supported, well informed investment plans to Ofgem. We have always utilised stakeholder engagement when developing our investment plans, but the scope for this activity has improved in DPCR5. However, as the DNOs start to address the varying and often opposing priorities of regional stakeholders, the importance of DNOs exercising their own judgement in deciding upon the investment plans submittedto Ofgem must be acknowledged.

It is important that customers understand and support the programmes for DPCR5. Ofgem must consider that some schemes may not get the support of the majority of customers due to the specific benefits of certain programmes (i.e. undergrounding, worst served customers etc). This acceptance may need to be tested in light of the recent increase in prices and change in economic conditions. Ofgem need to consider the impact of its decisions on customer bills but also be aware of how the current economic climate will alter responses on willingness to pay in the short term.

3.2 Quality of Supply

3.2.1 Overview

We agree with the Ofgem view that the existing quality of service incentive regime has worked well and delivered measurable benefits for customers. DNOs respond well to incentives in areas where they can control their performance and exercise their skills and resources to achieve required targets. The various mechanisms currently provide an adequate incentive for DNOs to focus upon service and not just the increasingly scarce opportunities to cut costs. If the current incentive rates are maintained, we believe our current service levels can be sustained in the medium term.

3.2.2 IIS

As stated earlier in this document, the current IIS scheme is an example of an effective incentive with an appropriate mechanism, sufficient rate to influence decisions and where performance is controllable by management. We believe that the current IIS mechanism's focus on underlying performance of the DNOs is still the appropriate target for DPCR5. IIS allows Ofgem to demonstrate how industry performance has improved under a robust and predictable incentive mechanism. We recognise that whilst the mechanism appears fundamentally sound, several adjustments have been proposed within both the Quality of Supply (QoS) working group and within Ofgem's initial consultation. Each of the proposals is discussed in our response to this chapter.

We believe that Ofgem needs to maintain the current incentive rates under the IIS mechanism. Firstly, any decrease in the rate will adversely affect the DNOs' ability to maintain current service levels and secondly, there is a concern that setting different exposure levels for individual DNOs provides the incorrect message. Equalising incentive rates for DNOs requires flexing the exposure (via cap and collar mechanism) for every company. Ofgem needs to strike a balance between customer risk and business risk. Companies need to be subjected to similar levels of risk to ensure customers in different regions receive equal efforts from their DNO to improve QoS performance. The most effective method to achieve this objective is via revenue exposure, a mechanism which has worked well through DPCR4. It is considered appropriate that all DNOs share an equal risk to performance against rates. At present all DNOs have 3% of revenue exposed to the scheme and are set equal performance bands of +/- 25% for CI and +/- 30% of CML.

(a) LV Disaggregation

The performance of the LV networks is becoming an increasingly significant part of overall network performance as DNOs continue to explore investment opportunities at HV. As a result of this increase in LV contribution to overall performance, the need to adopt a methodology which accurately compares differing circuit types becomes increasingly necessary. The existing split at LV between mains and services does not accurately reflect the network differences which affect performance at this voltage level. We believe that a more meaningful approach would be to disaggregate the network at LV in terms of overhead and underground. This would facilitate the determination of more meaningful benchmarks, particularly in terms of average supply interruption duration, which is especially important where LV networks are predominately underground resulting in inherently longer repair durations than that for overhead LV.

(b) HV Benchmarks

We recommend that Ofgem use a rolling 5 year period of data to calculate the average. HV network performance can be extremely variable when assessed on a year on year basis. As a result of this, it is important that Ofgem use a longer period to determine the average in order to prevent any current year performance dominating the benchmarking calculation.

(c) Band Dominance

There is a possibility that the disaggregation process currently employed to determine benchmarks for upper-quartile performance across the bands may contain statistical incongruities which manifest themselves in potentially unfair benchmarks for DNOs with atypical network characteristics. In particular, those DNOs that have a large proportion of circuits with a higher than average number of connected customers may well receive disproportionately low CI allowances. We would be happy to work further with Ofgem, as well as other DNOs, to better understand this issue and, if band dominance does indeed exist, to determine if it is material.

(d) Non-Attributable Faults

A significant proportion of non-attributable interruptions arise from events at higher voltages such as the slow operation of a circuit breaker, or some other such event which has the result of a loss of electrical infeed (LoI) to substation busbars. We welcome the proposal to benchmark LoI in the same way as for EHV/132kV. The remainder of non-attributable interruptions are associated with the reconfiguration of networks at the time of the fault outage which gives rise to customer interruptions - resulting in an allocation of customer numbers which is at variance to that in the benchmarking model. This model assumes a standard network configuration. It is our view that these 'mis-allocations' are not mis-allocations owing to error in data or reporting but are instead the natural consequence of the arithmetic process associated with the benchmarking methodology. We would very much welcome the opportunity to discuss this issue in more detail with Ofgem in order to better our understanding of the issue and to help Ofgem develop this proposal further.

(e) Pre-arranged Interruptions

Clearly the existing methodology for determining pre-arranged allowances has resulted in significantly varying levels of pre-arranged allowances between DNOs. Additionally, the utilisation of these allowances has also been mixed resulting in an apparent over-allocation of allowances for some DNOs. It could be suggested that this apparent over-allocation is actually reflective of achieved efficiencies within the DNO, who have employed improved working practices or a smaller capex volume which has resulted in a reduction in the required number of planned interruptions. We agree that it is appropriate that Ofgem should continue to incentivise performance in this area.

The factors which influence the volume of planned interruptions are varied; ranging from the operational policies and practices adopted within the DNO, the inherent network characteristics such as length of network, underground versus overhead and customer density as well as its topology. The volume of capex, although clearly relevant, is perhaps not a significant driver for the levels of pre-planned interruptions and probably not as significant as network factors.

It is clear the DNOs need to undertake planned supply interruptions in order to carry out works on the core distribution networks. It remains logical that the incentive placed upon these interruptions is set lower than for unplanned interruptions in order to prevent an increase in costs.

Despite a lot of investigation, there remains little evidence to support a direct correlation between capex activities and volumes of planned interruptions. We suggest therefore that Ofgem give consideration to the adoption of allowance setting which is based upon an individual DNO's 5 year average outturn for planned interruptions. If in any given year the activity increases, resulting in a rise in the number of planned interruptions, then this would be reflected in future targets. The ENA Quality of supply working group is developing a template for reporting future requirements based upon current (and historic) positions minus any extraordinary items plus any new drivers (such ESQC changes and other legislative drivers). We feel that this will appropriately allocate pre-arranged allowances.

(f) Frontier Performance

We believe that there is an inconsistency in the treatment of frontier performing companies in respect to different measures. Companies outperforming their benchmark CI level have targets set at actual performance levels whilst frontier companies in terms of CML performance can either be allocated upper quartile benchmark targets or actual performance levels with compensation for accepting more difficult targets. Ofgem needs to clarify why the issue of frontier performance is only applied to DNOs who are outperforming their CML target. There are companies who are outperforming their CI target which should benefit from the same methodology. We outperform our target consistently and as such when it comes to setting new targets Ofgem simply set the target equal to their current actual (as opposed to benchmark). This disparity needs to be addressed. Ofgem have previously suggested that DNOs who currently outperform their CML target would have no financial incentives to improve CML performance. We believe that this treatment is incorrect; DNOs still can access CML incentives up to the point of the cap.

Ofgem need to clarify the reasons why they are concerned about CML outperformance and not CI outperformance. For instance, we received no capital allowance for CI improvements in DPCR4 – as our performance was better than the benchmark - yet have still made improvements through this current price control in CI performance which has been achieved through investment in quality of supply funded via the incentive rate.

(g) Under Performance

The provision of an allowance for poorer performing DNOs is probably no longer appropriate. DNOs have had several years to invest in their networks to improve relative performance and as such any further improvements should be funded directly via the IIS mechanism.

The proposal to set a higher incentive rate to encourage poorer performing DNOs to improve performance needs careful consideration. This implies a bi-lateral approach to the IIS mechanism as opposed to the general approach which has proved successful to date. Any changes to the percentage of revenue exposed to the scheme or adjustments to the performance band would have the effect of altering the risk profile of the DNO, and could ultimately have an adverse effect upon their proactive stance to performance improvements.

(h) Audits

We welcome Ofgem's proposal to continue the current audit arrangements into DPCR5. The concern in this area relates to the audit procedures rather than the structural arrangements. Ofgem's current requirements are based upon overall accuracy of reporting, with the standards being linked to the IT costs DNOs were allowed in DPCR3. If these requirements around the audit change, then the systems may need to change which will have a cost impact.

The long held concern relates to the process if a DNO fails an audit. Ofgem will adjust revenues after a slightly larger sample is taken. The concern is that the audit is based upon a very small sample in the first instance that is not necessarily reflective of the population. We believe that if Ofgem is concerned by the results of an audit, a larger sample which would be more representative of the data population should be required. If this confirms that the data is robust, then the cost of the larger sample should not be borne by the DNO.

(i) Severe Weather Threshold

One of the reasons why the IIS mechanism has been so successful is Ofgem's ability to demonstrably improve base performance through the use of an incentive. Most parties (including customers) appreciate that network performance under stormy conditions is unlikely to match normal conditions. It is therefore concerning that Ofgem are discussing the removal or dampening of the exceptional event mechanism. Moving the exceptional events exclusion from QoS scheme will move the incentive from a sensible premise of base performance (average performance under normal conditions) to total network performance which may drive different investment behaviours. Moving the current threshold will also require revised targets to reflect the inclusion of exceptional events which creates additional complications. Returning to our earlier theme of the principles of a good incentive mechanism, if company performance on a specific metric is uncontrollable by management, the mechanism will ultimately be ineffective. The introduction of an additional uncontrollable variable (namely the weather) into the target setting mechanism will introduce both variability and uncertainty of rewards.

It is widely accepted that weather patterns in the UK have altered. The changes have seen both increasing temperatures and increasingly violent storms which have had an increasing impact upon the networks. This continuing development in the UK climate, matched with the proposals to include more significant events within the target, places additional uncertainties, and therefore risk, upon the DNOs.

Whilst there have been 27 exceptional events on average per year between 2004-5 and 2006-07 it should be recognised that this actually represents 27 claims from DNOs for exemption and not 27 individual severe weather events. It is likely that a bad weather event will move across large parts of the country affecting more than one DNO.

The current threshold is set at 8 times the daily norm which was chosen after a period of careful consideration of the IIS incentives and based on the following points:-

- It is statistically significant
- It is at a level which affects a DNOs normal non-storm fault activity
- The level would require almost all overhead resources in the company to respond to the event.
- The number of exemptions per DNO per annum were not excessive (1-2 p.a.) and hence the impact is reasonable.

We feel that any changes to the exceptional definition, which have the potential to weaken the incentive to improve underlying performance, would be a retrograde step and that Ofgem should be careful to avoid this impact. It should be acknowledged that the current mechanism has successfully driven DNOs to improve service and preparedness in storms and it not clear how any changes to the threshold would materially affect the service to customers. We are, however, conscious of the need to protect customers against the potential financial risk that the exceptional events mechanism poses. One way this could be achieved would be to re-introduce a materiality test to exemptions based upon total number of CIs and possibly CMLs which are associated with a particular event.

We note Ofgem's concerns relating to DNO performance under exceptional events. DNOs have learnt several valuable lessons from the severe weather incidents in recent years to improve the service they provide, particularly from a communication standpoint. There is no evidence that DNOs' performance during exceptional weather events is negatively influenced by the exemption threshold. DNOs prepare themselves for severe weather by ensuring that field staff are available should they be needed which includes liaising with neighbouring DNOs. It is impossible for DNOs to know beforehand whether or not the fault count will exceed the threshold and therefore DNOs are committed to providing a continued response during these events.

(j) One-Off Exceptional Events

One-off exceptional events are becoming an increasingly important issue for DNOs. The risks associated with one-off exceptional events is significant, particular in terms of the un-capped liability under the GS.

We are very keen to work with Ofgem to explore the issues associated with the current financial liabilities faced by DNOs following forced outages during periods of construction and maintenance activities. This is an issue which is almost exclusively related to unforeseen or unexpected events at 132kV and 33kV. During periods of asset replacement, in particular of grid transformers or primary switchboards, DNOs are required to significantly reduce the security of its related networks. Whilst this reduction in system security is totally compliant with appropriate planning standards, it does place connected supplies at a much reduced level of security. If during this period the network was to experience a forced outage of one or more of the remaining assets, then the results could be the widespread loss of supplies for a period equal to the emergency restoration period of the planned outage or, in extreme cases, the repair time of the failed asset.

The probability of such a situation becoming manifest is very small. Distribution assets are in fact very reliable and resilient and these characteristics were appropriately considered during the original development of the planning standards in the mid 1970s. However, the consequences of such an event are significant. Not least the effect that loss of supplies would have on local communities. A key issue for DNOs however, is the potentially significant financial liabilities which would flow from IIS and GS. In any one year for ENW there is the potential to experience a £14M swing in IIS revenues from a position of maximum reward to a position of maximum penalty. However, perhaps more significant is the uncapped liability associated with the GS payments, which for the loss of a typical ENW/NG 132kV GSP for a period of 48 hours could result in financial loss of upwards of £10M for GS alone.

The natural consequence of this risk, and the associated liabilities, is that DNOs have adopted an increasingly risk averse approach to construction and repair activities at 132kV and other EHV voltage levels. This risk aversion has the affect of increasing the overall costs associated with the delivery of asset replacement and reinforcement projects as DNOs become increasingly willing to invest capital in activities which have the sole purpose of mitigating the risks associated with the potential unplanned event.

Guaranteed Standards

We ask Ofgem to consider placing a cap on these liabilities which would better enable DNOs to react more proportionately to system risks during periods of reduced system security. We propose that a cap of £200 per connected customer for GS payments is introduced thereby limiting the GS liability. This payment remains however sufficiently high to influence DNO behaviour to ensure that appropriate steps are followed to protect consumers supplies.

IIS

The IIS liabilities equate to a possible 6% reduction in expected revenue for DNOs in cases where an event has the effect of reducing IIS performance from maximum reward to maximum penalty. As a result of this, DNOs are encouraged to adopt costly mitigation measures during delivery of large scale capital projects, whilst the probability of an event occurring remains low. Similar to GS, this effect is considered undesirable and ENW would encourage Ofgem consider options for a reduction in the IIS risks associated with one-off events. As the contribution to overall IIS targets made by interruptions at 132kV and EHV is low when compared to HV and LV, Ofgem could give consideration to the adoption of a separate scheme for transmission voltages. The scheme could operate in much the same way as the existing scheme but would provide the protection of a lower cap on potential penalties and one which is comparable with the rewards available from improved performance. Whilst further work would be necessary to establish the level of the cap, ENW would propose that the cap be proportional to the contribution made to current overall targets by transmission voltages.

3.2.3 Worst Served Customers

The IIS incentive mechanism has been particularly successful in incentivising DNOs to improve overall network performance but is predicated on the basis that investments to achieve improvements are funded from out-performance of agreed performance targets. Naturally, DNOs have concentrated investments on those parts of the network where expenditure has the potential to deliver the biggest rewards which normally occurs on high customer density parts of network. Customers who experience the lowest service levels are usually in rural areas served by networks with fewer connected customer where, under the existing framework, companies are unable to build appropriate business cases for economic investment programmes.

Worst Served Customers (WSC) are affected by a combination of poor LV and HV performance, both of which have different drivers (opex, planning and policy impacts upon LV whilst capex projects affect upon HV performance).

We suggest that discussions relating to worst served customers need to be tackled in the following manner:

- The industry and regulator needs to establish a definition of a worst served customer. The work conducted within the various working groups has suggested that the mechanisms will need to address specifically the WSC relative to customers in general within a DNO's operating area, should focus on HV network faults and should exclude the impact of exceptional events. We believe that this is a sensible premise to take the work forward.
- The DNOs need to identify how a specific investment programme or additional maintenance programme could improve the level of service to the affected parties.
- Discussions will need to take place to assess how the specific programme costs should be funded and if this would take the form of an allowance or an incentive mechanism.

Whilst no agreed definition exists of a worst served customer, it is considered likely that these customers are those who are affected by a higher than average number of HV and LV faults over a prolonged period. Quite often these customers will reside in rural areas, in low numbers, and at the extremities of existing networks. It is clear that the existing arrangements are not entirely appropriate to incentivise DNOs to improve network performance to these groups of customers. We have considered carefully the proposal by Ofgem to introduce a possible incentive based scheme for worst served customers in which a threshold based on interruptions could be determined. Targets would be set and DNOs rewarded or penalised based upon performance around these targets. It is not clear to us how such a scheme could prove successful given the current uncertainties surrounding definitions of WSC and in particular given the potential costs associated with delivering performance improvements to these groups. Given the physical constraints associated with existing rural networks, improvement investment is likely to be significantly high (perhaps even prohibitively so) and therefore the associated incentive rate would need to be very high indeed if such investment was to be self funding. These necessarily high incentives would raise questions about willingness to pay, cross subsidisation of rural customers by non-rural customers, as well as the potential material change in risk profile for individual DNOs.

It is possible that the introduction of a specific allowance which would enable DNOs to consider options for network improvements to these groups. The options available could vary significantly from refurbishment of existing assets and reinforcement of existing networks to the introduction of improved operational response measures to mitigate the affects of supply interruption in these areas.

We would like to stress that any attempt to introduce guaranteed standards aimed at providing some level of compensation to customers that fall into the category of WSC is unlikely to result in any material improvement in the reliability of their supply. The introduction of a GS payment would in effect merely allow such customers to enjoy a free service – albeit one which has a below average reliability.

3.2.4 Short Duration Interruptions

Another issue which has been raised during prior price controls is the increase in the number of short duration interruptions (SDIs). Networks have seen a 24% rise in numbers of SDIs in last 5 years. Evidence suggests that the total number of interruptions on the networks have remained stable over the same period. This suggests that the Quality of Supply incentive mechanism which targets customer minutes lost has had the desired impact of shortening the length of supply outages. Technologies introduced to respond to the incentive mechanisms (namely automated network switching) have been successful in minimising disruptions. To date, we have invested significant amounts of discretional investment in automation technologies across the network in response to the incentives offered by IIS. It is very important that the future benefits of this investment continue to be realised.

Additionally, there is a need to establish a common understanding of a short duration interruption and clearer definitions and reporting guidelines need to be established. The availability of a number of years' consistently reported data would be needed to facilitate a robust methodology for treatment of this type of interruption. It is also important to recognise the impact that SDIs have on customers. It is clearly less desirable to have a longer duration interruption than a shorter one but we are conscious of the potential consequences of SDIs on industrial and commercial customers. Once a common approach to reporting has been established this is an area which would benefit from further investigation.

We suggest that the increase in SDIs has similar issues to WSC in that they are a product of the successful incentive mechanism to improve average customer performance. We consider that it would be inappropriate to change the current incentive mechanisms but it may be worth investigating if additional funding outside of the incentive may improve performance in this area (if it is desirable and supported by customers).

We would encourage Ofgem to agree definitions and reporting requirements in respect of SDIs. At present reporting is likely to be inconsistent between DNOs – thus hindering the accurate analysis of the available data. Establishing accurate data in this area would facilitate the introduction of possible future changes which would have the effect of encouraging DNOs to address the potential increase in number of SDIs.

It is important that any potential changes to the requirements in respect of short duration interruptions avoid compromising the future benefits of existing investments which have been made by DNOs to improve overall network performance.

3.3 Telephony incentive scheme

The current telephony incentive mechanism provides little opportunity for DNOs to invest in the service provided to customers but will guarantee minimum standards of performance. Ofgem should review the current mechanism in line with the willingness to pay study to ensure that the balance between rewards and penalties and the relative level of each is appropriate.

Ofgem has made numerous comments relating to the telephony incentive scheme although it is not clear what additional measures and procedures Ofgem would like DNOs to address and if this will elongate the current process or replace it. We believe that the broad spectrum of customer research already in place, including internal surveys, ensure that DNOs are regularly identifying a wider scope of customer service questions than those captured in the Quality of Telephone Response survey. DNOs have become more pro-active in identifying where customer service can be improved to enhance their overall scores in the league table. DNOs could potentially have a customer survey at the end of the automated call to capture 'real time' feedback from the customer. This will not breach Data Protection and will provide a wider spectrum of quality monitoring. Ofgem would need to be mindful of the increased call handling times and therefore impact on resource and costs.

One improvement which could be introduced to the current system is the recording of unsuccessful calls and surveying the resultant customer experience. This would help to support a fairer system of measurement across the industry and give a full view on the level of call flushing. We believe that there is an inappropriate incentive to flush calls as the practice is not penalised.

We believe that there may be more scope to share best practice within the industry, and perhaps more media communication via phone-ins, radio, customer focus groups etc. The introduction of regional workshops engaging with our wider stakeholder group provides the opportunity to communicate to a wider spectrum of stakeholders and co-ordinate feedback.

3.4 Guaranteed standards of performance

We recognise the role of the guaranteed standards within the industry and accept that, in most cases, the penalties are appropriate and measured. In a small number of cases, the current or proposed measures do not drive the correct behaviours.

Additionally, the proposal to move from 18 to 12 hour on GS2 may drive incorrect behaviours for DNOs. Ofgem is looking at this issue from a compensation driven view, mirroring the general customer view. From a network view, moving to a 12 hour time limit incentivises DNOs to stop attempting to repair faults at 12 hours which may result in longer outages for customers. This appears to create a perverse incentive. It must be recognised by both business and domestic customers that the GS scheme was not designed to provide compensation for outages or service failures, but to penalise companies for those failures. DNOs have established fault response processes and working patterns which are targeted at ensuring that supplies are restored before the current trigger point is reached – in most cases significantly before. However, a change to the trigger point may well mean that the DNO has very little opportunity to restore supplies before the trigger point and this could create or influence negative behaviours resulting in an even longer period without supplies for customers.

We support the new redress scheme for the energy sector and have signed up to the voluntary TOSL scheme until the statutory scheme is implemented in October 2008. We recognise the driver provided by the replacement of energywatch to have clear complaint handling procedures to ensure there is no dip in customer service levels during the transition period. We have a proven track record of placing customer service at the forefront of our operations.

The discussions surrounding the implementation of the CEAR Act requirements appear disproportionate. The history of handling complaints in the energy sector can be distinguished between the GDNs and the DNOs and there is no particular record of poor performance by the DNOs. We therefore do not think a further GS on complaint handling is necessary at this stage and that the adequacy of the new complaint handling standards should be tested for a period of time before any decision on a new GS for DNOs is taken further.

Ofgem's proposals to create a consumer panel to provide a consumer insight on DPCR5 issues should be supported by the industry. We recognise that the DPCR5 process will be the most focussed review in terms of consumer engagement and the formation of a consumer voice to add to the proceedings is a further demonstration of the strides made by the industry and the regulator.

It is concerning that Ofgem are considering reviewing the arrangements for business customers. We believe that Ofgem's view that it is not technically feasible to offer business customers a different level of service to that offered to domestic customers remains valid. The value of loss of load to business customers is something which only they themselves are able to assess and the current penalty payments associated with failure of guaranteed standards was never intended to be a means of compensation to customers. If business customers believe that the risks associated with loss of supply require additional mitigation over and above that offered by DNOs, then they would be best advised to investigate the introduction of additional measures for ensuring essential supply continuity during these periods.

Business customers will always want higher levels of compensation as a way of reimbursing them for any lost business. Many accept that a continuous supply without any loss is not possible. Business customers cannot recover pure economic loss in the legal sense where a DNO has not been negligent and the GSs should not be utilised as a way around that. The traditional view of a GS scheme was to primarily protect domestic customers and those less able to protect themselves and the spirit of the scheme should be maintained.

We agree that the severe weather standards have provided greater clarity for industry participants and in communicating with customers during severe weather events. These measures were put in place to reflect the fact that DNOs' ability to react under storm conditions is hampered and as a result of Ofgem's concerns relating to performance under abnormal conditions (a theme which has reappeared within this consultation). We suggest that the current arrangements are measured, balanced and effective.

We believe that the measures relating to the Distribution Fuse and Voltages are now unnecessary either as a test of a DNO's service or as a standard which is rarely failed and is therefore of little relevance to customers.

From the simplicity and transparency standpoint, there is a superficial attraction to the suggestion of "a total duration" standard. It would be important for the industry to do some modelling of this proposal based on a number of different scenarios dependent on the number of hours proposed for the standard. DNOs would be concerned if the introduction of such a standard would add significantly to our cost base unless this was reflected in the price control settlement.

3.5 Connections

We have encouraged the development of competition in connections in our distribution service area for several years. Taking advice from a wide range of stakeholders, including Ofgem, we have made considerable efforts to restructure our connections business activity to demonstrate that all connections providers are treated equally and served well by our non-contestable activities

We believe that the general criticism of the industry for connections performance is unwarranted. Several DNOs (including ENW) have made considerable improvements in this area over the DPCR4 period. The competitive connections market is starting to have a positive effect for customers in some areas of the UK. Ofgem should persevere with the current framework and should utilise incentive mechanisms to encourage DNOs to partake in competition. One of the key elements that should be considered is revoking the current rules which ensure that DNOs are unable to make margins on contestable works. In terms of a connections business attempting to enter a regional market, the maximum margin attainable (assuming that the ICP charges the same rate as the DNO to price competitively) is the difference between the standard unit costs and the actual project cost. This has two negative results in terms of progression of competition. It reduces the scope of the market to those where actual costs are lower than average unit costs (i.e. where companies are able to "cherry pick" sites) and the lack of a margin (or even what could be deemed as normal profits in economic terms) will not encourage additional market entrants.

Ofgem note some specific concerns relating to the competitiveness and service of the connections businesses. Some of these issues will be addressed by the introduction of SLC15 (formerly 4F) and this licence change has not been given sufficient time to become embedded into business practices to conclude on the effectiveness of the mechanism. SLC15 should address concerns regarding delivery of quotations for Competitive Connections, and the delivery of specific non-contestable works i.e. initial jointing and energisation.

Several of the suggestions included within the consultation appear to be overly aggressive (e.g. structural separation), but the premise of revenue adjustments or awards for leadership in connections related activities may be a more appropriate mechanism. Historically, DNOs have embraced incentive based regulation and adopting this approach may be a more effective tool to adopt.

In response to the long-held concerns relating to market competitiveness, we have submitted a report from an independent consultant which reviewed the level of competition within the North West of England. The report, plus accompanying letter, suggests that there is effective competition within the region. We have the highest rate of competition in our Distribution Services Area of any DNO with respect to new connections, and have adapted our processes throughout the last two years to enable competition to flourish further and to provide greater levels of customer service.

Over the last two years we (through our service provider UUES) have been encouraged by the competitive pressure we have been experiencing to make significant strides forward in our customer service in the area of Connections. Our service provider:

- has based the Statutory (Manchester and Head Office) and Competitive LV and HV Connections in one location;
- is currently setting up a dedicated customer enquiries interface team;
- has updated our web-site information in terms of application forms and is in the process of producing user guides to assist with applications;
- has one standard process for application forms i.e. applications into one central repository;
- provides key customer liaison i.e. local authorities, developers, ICPs/IDNOs.
- provides an online auditing mechanism (MBA) for ICPs/IDNOs.
- provides a construction guide for developers

We believe that Ofgem's priority for the connections market should be the availability of choice. DNOs should not be penalised in any way if customers choose to utilise the services of the incumbent service provider and avail themselves of the statutory provision. There is often a perception that competition is only working if market share is lost by the DNO, but this is the only measure of success.

We do not agree that standard pricing for domestic customers is appropriate; regional cost variations and different scopes of jobs would result in charges which are not cost reflective. Our current prices are based on reasonable direct and indirect costs incurred only, but vary through different regions (i.e. the business has two principal contractors providing the works at LV and HV).

The treatment of connections margins should be addressed within DPCR5. The RRP treatment of connections margins has been consistently applied to all connections businesses of a DNO and any affiliates. Therefore, this historically meant reductions in our RAV because of the success of the multi-utility competitive connections business of the United Utilities Group, United Utilities Networks Limited (UUNL). Following the sale, there is now no relationship between the two parties (ourselves and UUNL). UUNL continues to operate in direct competition with us and is working with Independent Distribution Network Operators (IDNOs) to bid for projects within our region. UUNL claim that they can not be competitive in the connections market unless they can find an IDNO to offer an Asset Adoption Payment to defray some of the connections costs. We are now in the absurd situation that we may suffer a reduction in RAV as a result of the success of UUNL to help one of our competitors out-bid us for a network extension. UUNL only continue to provide information to enable us to complete our RRP submission because of the goodwill we have established through our commercial relationship with their parent company and have already complained to us that the cost burden of such reporting is inappropriate. Whilst we realise that the current situation is a result of a number of understandable historic decisions, it is now wholly inappropriate.

3.6 Customer service reward scheme

We recognise that Ofgem want to encourage DNOs to improve the current service available to customers in areas which do not naturally lend themselves to a measurable incentive mechanism. The DNOs recognise that the current discretionary reward scheme has helped to clarify Ofgem's objectives in terms of service priorities but the discretionary reward scheme is the least attractive incentive, as it relies on short term regulatory judgements. The DNOs have concluded, via the ENA, that "It may be prudent to have such a device in reserve to allow rewards to be offered for performance in areas that did not appear, at the time of the review, to warrant separate incentivisation, but it seems less appropriate to declare such a mechanism as a potential source of arbitrary penalties as well. If companies' behaviour warrants regulatory intervention to reduce allowed revenue it should be done through a more formal process than one-off adjustments".

Appendix C1 – Answers to specific questions in Customer Chapter

Question 1: Do the current regulatory arrangements deliver the levels of service that customers expect?

We believe that the current arrangements are fundamentally correct and support an incentive regime. Many years of an incentive based regulatory framework has delivered considerable benefits to customers in the form of lower prices and higher quality of service. In addition to the benefits to customers, the existing regulatory framework has seen significant improvements in operating efficiency whilst providing support to the competitive retail market which has also assisted in improving the customer experience. Successive surveys have shown that the general mass of urban customers enjoy high levels of service with most never losing their supply and suggesting that the existing arrangements are delivering the service that customers require. This has been achieved by a stable regulatory environment, a mechanism which correctly incentivises companies to improve the average customer experience, and incentive rates which mirror the value placed on service improvements. We agree with Ofgem's suggestion in paragraph 3.3 that it is not appropriate at this stage to raise the bar on current standards and incentives in all areas. However, investments have been made in DPCR4 and companies should not be subjected to declining rates. Ofgem needs to clarify the difference between customer expectations and requirements. Performance has ratcheted up over the previous price controls and expectations are now in excess of that reasonably required in some areas.

We, and the rest of the industry, have learnt lessons from severe weather incidents in recent years to improve the service we provide particularly from a communication standpoint. Customers expect and understand that DNOs are under exceptional circumstances when dealing with the severest of storms and will accept that the responses may not match that experienced under normal conditions. Effective communication in these cases becomes increasingly important.

Question 2: Is the focus and scope of the current regulatory arrangements correct and are there any gaps that need to be addressed?

Price controls are, by design, targeted to incentivise DNOs to reduce their cost base. This will drive behaviours in companies which may not be in the interest of consumers. The focus of previous price controls has been to correct the undesirable consequences of the RPI- X mechanism with specific incentive mechanisms which, if implemented correctly with adequate rewards (or penalties), will modify industry value drivers to match those of the end customers. The incentives introduced in the previous price control reviews have targeted improvements in the level of service of the average customer with some measures to guarantee a minimum service standard. This focus is still appropriate for DPCR5 to ensure that investments from previous price controls are correctly funded and that general industry performance, which has improved through the incentives, is maintained. There may be some scope to improve the performance for worst served customers but proposals which require cross subsidisation of customer types (i.e. rural vs. urban) must be considered carefully as large scale programmes are unlikely to be supported by the majority of stakeholders.

Question 3: Are DNOs customer focused enough or should they be doing more to improve communication with customers?

Ofgem have correctly identified the interaction of DNOs with its customers as one of the core themes for DPCR5. The various mechanisms incorporated into earlier price controls have put the DNOs in a balanced position where the efficient levels of customer service activities are adopted by the industry. The current period of stakeholder engagement provides an opportunity to review the current arrangements and understand what a DNO could be doing. At the same time, Ofgem must be mindful of what a DNO should be doing.

We recognise the need for a Quality of Telephone Response scheme to improve understanding of customer requirements but suggest that the proposals contained within the initial consultation may overly complicate the current mechanism. We need clarity on the nature of the broader view that Ofgem think we should cover. We are concerned that some of the suggestions may elongate the process if the new questions do not replace some of the current questions.

We believe that the broad spectrum of customer research already in place, including the DNOs' internal surveys, ensure that the industry are in fact regularly identifying a wider scope of customer service questioning other than those captured in the Quality of Telephone Response survey. DNOs are becoming more pro-active in identifying where customer service can be improved to enhance their overall scores in the league table.

One option for Ofgem would be to encourage more best practice sharing within the industry, perhaps more media communication via phone ins, radio, customer focus groups etc.

DNOs could potentially have a customer survey at the end of the automated call to capture 'real time' feedback from the customer. This will not breach Data Protection and will provide a wider spectrum of quality monitoring. Ofgem must decide how to balance the need for qualitative information and impact of increased call handling times and the resultant impact upon resource and costs.

The introduction of regional workshops engaging with our wider stakeholder group as part of the DPCR5 programme has provided the opportunity to communicate to a wider spectrum and co-ordinate feedback.

One proposal which we support is the recording of unsuccessful calls and surveying customer experience as this will help to support a fairer system of measurement across the industry and give a full view on the level of call flushing. There is currently an incentive to call flush as the practice is not currently penalised.

The major concern highlighted by Ofgem in recent years is the response of DNOs under storm conditions. Ofgem must recognise the differing pressures on DNO resources in times of both emergency and normal conditions which need to be considered in isolation.

Question 4: Is DNOs' financial exposure set at the right level and/or do we need to change the emphasis in certain areas?

The DPCR4 settlement included specific measures which exposed DNOs to levels of risk that Ofgem deemed manageable. The initial consultation has included several comments which appear to widen the mechanisms without a discussion of the change in risk exposure.

- Ofgem have suggested that a consistent IIS incentive rate for all DNOs may be introduced in DPCR5. Moving to this mechanism will require a flexing of the financial exposure. This needs to be considered carefully given the investment made by networks and the resulting improvements. It will also result in some perverse incentive rates for high and low performing companies.
- The initial consultation did not address the potential for uncapped GS liabilities associated with large loss of supply events considered to be in the control of DNOs. Several DNOs have raised this issue within the Ofgem quality of supply working group and it is felt that DPCR5 provides an opportunity to remove this potentially harmful anomaly. Additionally, moving from an 18 to a 12 hour threshold on GS2 is unlikely to improve customer performance experiences. This will only result in increased liabilities.
- The various discussions surrounding the movement of the boundaries of exceptional events will increase potential liabilities for the DNOs above the current levels of exceptional event exposure.

The document proposes increased exposure for the regulated businesses but does not propose any opportunities. The discussions on the cost of capital for DPCR5 will need to include the increased risk exposure. We feel that the DPCR4 settlement (with the exception of the uncapped GS liabilities) provided an acceptable balance of risk and reward. The current discussions suggest a dampening of incentives and an increase in risk without an appropriate discussion on returns.

Question 5: Do you think we have identified the right issues and appropriate areas for development with the existing incentives?

Ofgem has raised numerous customer issues and areas and has correctly adopted an evolutionary rather than revolutionary approach to the specific incentive mechanisms. Some of the projects discussed within the customer chapter appear to be reasonable although it is worth noting that most of these developments (worst served customers, short interruptions) may be a product of the current incentive regimes and therefore programme based solutions (in line with the visual amenity mechanism) may be more appropriate rather than additional incentives or developments to the current mechanism.

One area which has not been discussed within the document is skills and training. In the GDPCR, GDNs were provided with allowances to ensure that an adequate number of trained staff is available to deliver the next price control programmes. This issue is mirrored within the electricity distribution industry and discussions on appropriate allowances should commence.

Chapter 4 – Networks

4.1 Introduction

We believe that there are a number of emergent issues in the networks area that will mean a change in the balance of investment between traditional and non-traditional areas. In particular, we foresee an increase in non-load investment on the network for end-of-life considerations and for other reasons, as the role of the network, the consequential impact it has and the performance expected of it changes.

We note in particular the presence of an environmental driver behind many of these areas (oil bunding, fluid-filled cables, undergrounding, noise etc.) and observe that consideration of environmental impact should not be restricted to a discussion of climate change and that, from a networks perspective, climate change adaptation is at least as important as actions to facilitation emissions reduction. This means that careful consideration of flood protection, severe weather resilience and coastal inundation effects will need to be incorporated into DNOs' plans as the assets installed in DPCR5 may well be required to cope with the projected climate of the 2080s.

These changes in the balance of DNO activity, combined with new options for cost modelling that are possible because of improved data availability, mean that it is appropriate for Ofgem to develop new approaches to assessing DNO proposals. We support Ofgem's proposals to develop new approaches to modelling expenditure requirements.

4.2 Proposed Building Blocks

We welcome the introduction of the building blocks approach and its promise of clearer definitions and the removal of distortions. In particular, we believe that the new 'Network Costs' grouping will eliminate some of the tortuous definitional issues associated with current reporting, and be better aligned to a prudent whole-life asset management approach. We also welcome acknowledgement that several indirect cost categories are associated with delivery of direct work and would strongly support vehicles & transport and stores costs being included in this category.

4.3 Assessment of DNOs' proposals

We agree with Ofgem's intention to place more emphasis on our forecasts and the incorporation of regional requirements, but point out the inevitable diminution in comparability that will result. Ofgem's willingness to review cost modelling approaches and open-mindedness to consider alternative approaches is essential in ensuring appropriate assessment of regionally focussed proposals. In addition, it is important to recognise that DNOs have been incentivised to improve efficiency as measured by the models utilised in DPCR4, particularly Normalised Controllable Costs and Faults. It will be important to repeat the analysis of DPCR4 as a reference point from which to evaluate new methods and to demonstrate a degree of regulatory consistency. However, given developments such as recent demand reductions, it is important to also recognise that the role of history in determining future spend requirements is becoming increasingly unclear.

Given the evolving role of DNOs, increasing investment programmes and a move to investment programmes tailored to regional requirements, it is important that new models are developed to assess required spend. The data available from the annual

RRPs is better than that available in DPCR4 and will provide scope for alternative modelling approaches to be considered. However, there are still outstanding data issues, largely as a result of residual boundary issues, that must be recognised in modelling. It is extremely important that cost modelling approaches recognise the real drivers of costs and that models are developed with the building block approach to allowance setting in mind. Models that ignore drivers of cost and changes in drivers will incorrectly influence allowance calculations. Comparative efficiency should be used in conjunction with cost projections in determining allowances. We urge Ofgem to recognise the importance of fixed costs in considering efficiencies and the very material "cherry picking" effects that can result from disaggregated approach to cost analysis. It will always be necessary to use top-down analysis to assess the scope of cherry picking in more disaggregated cost models.

We also welcome Ofgem's acknowledgement of new and continuing areas of uncertainty. In addition to those noted in the document, other pressures we are experiencing include increasing pension costs, difficulties in gaining customer consents and a rise in vandalism as well as theft (& not just of copper). In particular, we welcome Ofgem's recognition of the significance of input price increases and strongly support consideration being taken of rising input prices in DPCR5 cost assessments. Our forecasts will endeavour to form a best view on all of these aspects but it is difficult to have a 'clear idea of the magnitude and impact' of factors outside our control as Ofgem imply.

We recommend that most of these uncertain costs are not included within the IQI assessment and are, instead, subject to an appropriate alternative mechanism as follows:

- pass-through mechanisms – for uncertain costs that DNOs have little or no control over such as pension costs, licence fee costs, NGT exit charges
- revenue driver/ trigger mechanisms – for activities where required volumes are uncertain but unit costs and drivers are reasonably well understood.
- incentive mechanisms – where the desired output is clearly measurable but the required technical solutions/ DNO activities are unclear.

We also suggest that it may be appropriate to normalise for other potential major distortions before applying an IQI approach, e.g. very large projects (say >£10M), whose cost and timing volatility is often high when being planned so far in advance.

Appendix N1 - Answers to specific questions in Networks Chapter

Question 1 – Have we captured all the key lessons learnt from DPCR4 regarding cost assessment?

We are encouraged to see that Ofgem have acknowledged so many of the issues with the DPCR4 process within their proposal. We are particularly pleased that Ofgem have recognised that a significant proportion of "indirect" costs are directly associated with undertaking work on the network and scaled by the size of capital programme rather than size of DNO. The proposal to consider these engineering indirect costs with direct costs will, to a certain extent, remove some of the disjoint seen in setting DPCR4 opex and capex allowances and will go some way towards preventing further perverse incentives for DPCR5. We would encourage Ofgem to consider stores, vehicles and transport, H&S and operational training and system mapping in a similar way, as these costs are also strongly associated with direct activities and costs will vary dependent on volumes of work undertaken.

Question 2 – Is our approach to cost assessment appropriate?

We recognise that cost assessment needs to be based on good quality, comparable data and have worked hard to ensure compliance with SLC48 (formerly 52) conditions. We would however point out that the RRP format and rules have changed each year since their introduction and so it can be difficult to ensure that systems are aligned to the latest requirements.

We also note that the historic RRP data only provides a portion of the data required for a BPQ and that the issued HLFBPQ in some instances requires this historic data to be reported in a different way. We look forward to working with Ofgem to ensure a consistent and transparent population of the HLFBPQ from previous RRPs.

We welcome Ofgem's intention to place more emphasis on our forecasts and incorporation of regional requirements but point out the inevitable diminution in comparability that will result. Stakeholder engagement and Ofgem's reluctance to frame a set of conditions that would form a standardised 'Base Case' implies that DNOs will submit regionally-specific programmes based on their best view of network need and the synthesis of stakeholder views. This will result in different propositions being presented. Ofgem will need to take care when deploying standard high-level models and instead place more emphasis on review and audit of DNO's proposals.

We also welcome Ofgem's acknowledgement of new and continuing areas of uncertainty. In addition to those noted in the document (4.11), other pressures we are experiencing include increasing pension costs, difficulties in gaining customer consents, fuel prices, introduction of the Traffic Management Act (TMA) and a rise in vandalism as well as theft (and that not just of copper). Our forecasts will endeavour to form a best view of these aspects but it is difficult to have a 'clear idea of the magnitude and impact' of factors outside our control as Ofgem imply (4.16). Stakeholder input can also often be contradictory and difficult to synthesise. The impact of competition and IDNOs on connections forecasts is similarly hard to predict.

With respect to the proposed mechanics of cost assessment,

- We suggest that detailed 2005/06 data is not particularly robust. Whilst we appreciate that you have asked for retrospectively stated data, we note that this is only to table 2.2 level which might not be sufficiently disaggregated for some models and that some further re-statement may be required. We also suggest that cost assessment should take place with pension costs excluded.
- We also consider that some of the proposed approaches to assessment outlined in the Consultation are of limited relevance – re-running the DPCR4 LRE methodology for example will not work if units continue their decreasing trend. This could produce a negative capex projection, whereas in fact most DPCR5 LRE is likely to originate from churn and urban re-development activities.
- With respect to the normalisation adjustments discussed in the document, top-down and bottom-up adjustments might be different depending on the extent to which models can adjust for real drivers and differences between DNOs. We see no mention in the list of singleton considerations or an acknowledgment of importance of fixed costs. Analysis based on seven DNO groups does not contain enough data points to determine a singleton effect. In particular, the skewing effect of EdF on model results can distort the analysis. A separate singleton allowance should be calculated instead.
- The current "75% rule" will not correctly identify inefficient related party margins. All related party margins should be included for modelling as removal of efficient margins would create a false frontier. Any inefficient margins will be apparent in DNO rankings.

When disaggregated modelling techniques are deployed, it will be important to eliminate the effect of cherry-picking. Cherry picking effects arise from:

- Different interpretations of cost definition
- Differences in operating model for example whether a DNO outsources direct activities and whether they choose to purchase or lease non-operational assets.
- Differences in company efficiency between types of activity
- Even if all DNOs are consistently interpreting cost definitions, cherry picking effects will still arise in models that rely on more than one sub-model as a result of differences in operating model and differences in efficiency within DNOs. These must be adjusted for in allowance setting.

We see little mention of Non-Operational capex in the document and noted its omission from the original HLFBPQ. We suggest that IT, Vehicles and Property are subject to specialist review and Small Tools costs are combined with the direct costs which they facilitate. Plant & Machinery could be combined with the Vehicles category, should there be significant spend in this area.

Question 3 – Are there alternative approaches to cost assessment that we should be considering?

We welcome Ofgem's willingness to review cost modelling approaches and your open-mindedness to consider alternative approaches.

The data available from the annual RRPs is better than that available in DPCR4 and will provide scope for alternative modelling approaches to be considered. However there are still outstanding data issues, largely as a result of residual boundary issues, that must be recognised in modelling. We take RRP very seriously, however amendments to RRP are made frequently, and indeed sometimes after financial year end, which means that accounting systems are not always configured to complete RRP as required.

Given the evolving role of DNOs, increasing investment programmes and a move to investment programmes tailored to regional requirements, it is important that new models are developed to assess required spend. These models will need to be matched to the building block structured and carefully assembled within an overall framework that also considers the inter-relationships between the blocks.

It is extremely important that efficiency modelling approaches recognise the real drivers of costs and that models are developed with the building block approach to allowances setting in mind. Models that ignore drivers of cost and changes in those drivers will incorrectly influence allowance calculations. Comparative efficiency should be used in conjunction with cost projections in determining allowances. We urge you to recognise the importance of fixed costs in considering efficiencies and the very material "cherry picking" effects that can result from disaggregated approach to cost analysis. It will always be necessary to use top-down analysis to assess the scope of cherry picking in more disaggregated cost models.

We agree that some activities do not lend themselves to comparative cost modelling, either because the costs are not controllable or because it is impossible to normalise costs and cost drivers across DNOs. However, it is important to recognise that provision must still be made to fund legitimate costs excluded from comparisons.

Question 4 – How might our approach to benchmarking be improved?

We agree that the data available for benchmarking is more consistent than at DPCR4, however we believe that there are still some residual boundary issues that means fully disaggregated analysis should be undertaken with caution.

- Many cost allocation issues remain outstanding. Ofgem have concentrated on direct/ indirect and opex/ capex boundaries, but in particular many boundary issues remain between indirect costs making disaggregated cost analysis inappropriate.
- In an ideal world we would prefer Ofgem to use a "cost block" approach where groups of costs with similar drivers are aggregated for modelling purposes as it allows more appropriate cost drivers to be used and allows a more considered allocation of allowances between opex and capex. However, we feel there are still some boundary issues that prevent us being fully confident in such models and we support Ofgem in continuing to ensure that DNOs allocate costs consistently. Even once all such boundary issues are ruled out, cherry picking adjustments would still be required.
- Top down approaches give good sense check and show consistency with previous approach
- To reduce the perception of regulatory risk Ofgem need to be evolutionary not revolutionary in their choice model hence should choose the upper quartile as benchmark and conduct top down analysis to test validity of bottom up results. The DPCR4 analysis should also be repeated and utilised as a reference point.

Care will need to be taken in the unit cost assumptions in the proposed re-running of the NLRE model; using simple statutory costs will not replicate the requested costs for the blocks as these are on a directs-only basis. Similarly, there will not be a 15-year set of panel data on a consistent cost basis hence the LRE model in its DPCR4 form will not work. Unit cost analysis needs to be extremely well defined if used.

We suggest that we are reaching a point where it is opportune to move on from historic modelling approaches and need different ways of assessing risk and outputs. Our pioneering developments in the area of Health Indices leaves us well-placed to contribute to this debate and we look forward to engaging with Ofgem at a detailed level.

We feel that the list outlined in 4.65 is sensible and gives the opportunity to remove historic distortions, for example, having a proportion of 'capex' (e.g. design & overheads) assessed once in the PB Power analysis and then separately (& markedly differently) in the efficiency regression. We also agree that some detailed review of expenditure is important to assess validity of proposals and think there would be merit in DNOs giving details of their biggest NLRE projects in a similar way to that proposed for LRE. We urge caution, however in using external/ international benchmarks without first ensuring consistency of cost definitions (especially capitalisation) and regulatory regimes.

Question 5 – Have we captured all the key issues for 'networks'?

We believe that there are a number of emergent issues in the networks area that will mean a change in the balance of investment between traditional and non-traditional areas. In particular, we foresee an increase in non-load investment on the network for reasons other than end-of-life considerations, as the role of the network, the consequential impact it has and the performance expected of it changes.

These issues are noted in the Appendix 8 discussion of building blocks, and we observe that these fall into the broad categories of Environment, Safety and Network resilience. We note in particular the presence of an environmental driver behind many of these areas (noise, oil bunding, fluid-filled cables, undergrounding etc.) and observe that consideration of environmental impact should not be restricted to a discussion of climate change and that, from a networks perspective, climate change adaptation is at least as important as actions to facilitation emissions reduction. This means that careful consideration of flood protection, severe weather resilience and coastal inundation effects will need to be incorporated into DNOs' plans as the assets installed in DPCR5 may well be required to cope with the projected climate of the 2080s. We will be in a better position to quantify these effects in the January 2009 FBPQ, informed by the publication of regional climate change scenarios by UKCIP in November 2008.

Question 6 – Is our building block approach to forecasting appropriate?

We welcome the introduction of the building blocks approach and its promise of clearer definitions and the removal of distortions. In particular, we believe that the new 'Network Costs' grouping will eliminate some of the tortuous definitional issues associated with current reporting, and be better aligned to a prudent whole-life asset management approach.

We also welcome acknowledgement that several indirect cost categories are associated with delivery of direct work and would strongly support vehicles & transport and stores costs being included in this category.

Question 7 – What is the scope for developing additional output measures and how can these be incorporated into the price control?

We welcome the acknowledgement that companies have advanced in their approach to condition and risk assessment and we commit to work further with Ofgem in this regard. Historically, the issue regarding an industry leap from age-based to condition-based forecasting has been the lack of common definitions and hence comparability but Ofgem's proposal of more bespoke forecasts (i.e. no 'Base Case) mitigates this somewhat.

We believe that there is scope for introducing additional output measures and look forward to working with Ofgem in this area. Measures fall into three categories;

- Those already established and in use, e.g. CIs and CMLs. Here, we should be looking to ensure that the metrics remain appropriate to the incentive mechanisms and whether the existing metrics can be adapted for other uses (e.g. potential use of CIs and CMLs to determine worst-served customers).

- Those that RRP has introduced that may be appropriate in determining outputs for certain building blocks, e.g. substations >95% loaded as a measure of network risk

- Those that DNOs have developed but for which no common standard applies, e.g. Health Indices. These may be less amenable to use as comparative indicators in the short-term, but can provide a mechanism for DNOs to calibrate their own programmes.

We also consider that in certain areas, there may be little alternative to assessing the efficient delivery of physical outputs as proxies for the deeper, more elusive metrics that they may be trying to achieve. A contemporary example is measuring the impact on visual amenity of undergrounding by counting lengths of line. It is likely that similar metrics may be required in areas such as flood protection, resilience, fluid-filled cable replacement, overhead line strengthening and others.

Question 8 – What is the best way for DNOs to gain stakeholder input to their forecast business plans and how should Ofgem facilitate/incentivise this?

As Ofgem are aware, we have started our consultation process with a successful event on 10th April, at which Ofgem were present. Two further workshops are planned in the North-West region, as part of an ongoing programme of communication.

We will need to consider with Ofgem the interaction of the customer research with the incorporation of stakeholder input, i.e. stakeholders are generally likely to be supportive of infrastructure investment where it supports their aims but this could add up to an unaffordable proposition. Stakeholder input is also unlikely to present a coherent view and DNOs will have to work carefully to distil and discern the best way forward.

We would also caution that expectations of the results of stakeholder input need to be managed as it has the potential to be contradictory and hence the DNO will need to remain the key arbiter in the process.

Question 9 – Is the IQI and capex rolling incentive the best way to ensure realistic forecasts and efficient investment?

We welcomed the introduction of the IQI mechanism and agree that it is an appropriate way for DNOs to present realistic forecasts. There are issues with the process by which a comparator is developed which are discussed in other areas of our response.

We acknowledge that we, in line with most other DNOs, have underspent capital allowances in the first two years of DPCR4, however this is largely due to the time required to mobilise additional resources in a constrained market and the need to re-evaluate project design to ensure that unit cost inflation did not make the necessary outputs overly expensive. We expect 2007/08 to show a significant increase in expenditure levels. We would point out that this analysis is skewed by comparing a rising anticipated spend profile with an unprofiled (i.e. flat) allowance. We also suggest that the overall overspend of opex and underspend of capex would appear to disprove the notion of perverse incentives driving inappropriate cost allocations (4.26).

We challenge Ofgem's view that current investment patterns suggest that the incentive to over-forecast and under-deliver is dominant. DNOs have an incentive to outperform their allowances where efficient and are also increasing capital expenditure year-on-year. The cumulative underspend to date is largely a function of an unprofiled allowance as discussed above. We note that Ofgem's Cost Report for 06/07 stated that companies were forecasting a +2 to -13% range of outturns against the FP.

Question 10 – How might the IQI and capex rolling incentive be improved or what additional measures could supplement them?

Basing the IQI on some blocks but not others has merit, but whether it is then appropriate to extrapolate the results across all areas of investment seems inappropriate. We will also need to consider the relationship between IQI application and forecasts – for example, if the IQI scheme 'marked down' NLRE, what would the corresponding adjustment be for the design elements etc.?

We also suggest that it may be appropriate to normalise for other potential major distortions before applying an IQI approach, e.g. very large projects (say >£10M), whose cost and timing volatility is often high when being planned so far in advance.

We recognise that revenue drivers can be useful where there is considerable uncertainty over the levels of future external factors. If deployed, care would need to be taken to ensure that an appropriate unit cost basis is used.

Question 11 – Should we aim to equalise incentives on network investment and business costs and how could this be achieved?

We recognise the attractiveness of equalising the incentive rates in order to avoid perverse incentives. However, we would urge caution in developing a framework to achieve this. Equalisation of efficiency rates would almost inevitably have the effect of weakening opex incentives and strengthening capex incentive rates. In a world where opportunities for further opex reductions are increasingly scarce, this may drive DNOs to cut expenditure inappropriately and/ or to underspend capital allowances in an unsustainable manner.

Question 12 – Is the timetable realistic?

We believe that the overall timetable is realistic. However, there appears to be repetition within March, June, July and August 2009 for “forecast data”. We would like to have more clarity on these requests and what these submissions would be intended to achieve. Such clarity would allow for better planning. For example, it would be helpful to understand how these various submissions will interact with the IQI base case assessment.

Chapter 5 Financial Issues

5.1 Introduction

We believe that there needs to be consistency across the price control building blocks and Ofgem should be transparent in how they have reached their conclusions on a number of financial issues. To maintain investor confidence Ofgem needs to ensure that key assumptions are fully debated, stakeholder views are sought and regulatory consistency is applied wherever possible. With this in mind, we believe Ofgem should make their financial model available to DNOs early in the process so that DNOs and Ofgem are discussing issues in the context of the same model. Issuing the model for the first time with the initial proposals is far too late in the process and will not allow for a constructive exchange. Further, DNO comment on the model can be a helpful validation of the model logic.

The price control review needs to be conducted in a way that encourages innovative financing structures, which are ultimately in consumers' interest, whilst providing protection for consumers through the financial ring fence. We believe the current ring fence arrangements as set out in the DNO licences are sufficient to ensure that consumers' are protected from unwarranted risk.

In the following sections we have set out our position on a number of key financial issues relevant to the DPCR5 price control. In the appendices to this chapter we have included our answers to the specific questions asked in the consultation document and provided supporting information.

5.2 Cost of Capital

Assessing the appropriate cost of capital is an extremely important element in the price control and in maintaining investor confidence in the regulatory regime. DNOs operate within different group structures and use different business models. The cost of capital needs to be determined using common generic assumptions for an efficiently managed DNO to ensure that innovation and the development of best practice is not stifled. Allowed returns at the price control need to be set at least equal to the assessed cost of capital.

We agree that the cost of capital needs to be balanced with the opportunities and incentives for out-performance in the regulatory package as a whole. For example, consideration needs to be given as to whether there is a requirement for an adjustment to address the inconsistency between setting the cost of capital based on an average efficient company in the industry sector and an opex efficiency target based on an upper quartile catch-up. What matters to investors are the actual rates of return earned by DNOs, which take account of the benefits of anticipated out-performance.

The cost of capital needs to be set to ensure that appropriate sources of funding are available to the DNOs. Setting the cost of capital too low will discourage investors from funding infrastructure assets. It is important therefore that Ofgem take account of the real world financing issues facing the DNOs.

We also agree with the respondents to the Financing Networks consultation that the use of a split cost of capital would be detrimental, increasing regulatory risk and undermining investor expectations of anticipated returns. It must be recognised that the academic concept of a split cost of capital does not reflect the way in which

0business finance and re-finance investment. Therefore this approach should not be adopted in the price control for the DNOs.

5.2.1 Cost of Equity

With regard to the cost of equity, Ofgem needs to send the right signals to the financial markets and be satisfied that their assumption is set at the appropriate level to attract and retain equity capital. This requires a degree of consistency with past approaches to the cost of equity assessment, but with an update to reflect the latest risk profile of the DNOs.

We note Ofgem's preference to use a range for total equity returns in its price control reviews, rather than the standard capital asset pricing model ("CAPM") approach. Given the practical limitations of the CAPM in terms of limited market data on the DNOs and difficulties in interpreting previous evidence on betas, we support the continuation of this approach for the current review. We make this comment in the belief that Ofgem should not make any significant changes to its assumed level of gearing (see section 5.2.3) and in the event that Ofgem does consider a significant change to gearing assumption then we would wish to re-explore the CAPM approach; given the inherent link between gearing and the cost of equity.

Further, we believe that Ofgem's previous range of 6.5-7.5% for total equity returns remains appropriate, as there has been no evidence of changes to long-term equity returns since DPCR4.

We urge caution in placing too much weight on the recent premia paid for regulated utilities, where a recent excess of demand over supply has contributed to driving the price upwards for many classes of infrastructure asset.

In this regard we acknowledge Ofgem's acceptance that high market-to-asset ratios or "MARs" do not necessarily imply that previous price controls have been too generous. There are several factors, other than the cost of capital, that justify companies paying premia to RAV including:

- access to asset class and the level of demand for such assets,
- expected RAV growth;
- any instability in the way costs enter the RAV, which can diverge from investor expectations;
- outperformance against the regulatory allowances; and
- incentives outside the price control.

Previous attempts to use MARs to directly estimate a company's cost of capital have been flawed. Evidence from specific company acquisitions are only representative of market conditions at the time of the acquisition and cannot be assumed to be indicative over a longer timeframe or of the whole utility sector. The Competition Commission (CC) concluded in its work on the BAA review that it was unable to draw any conclusions about the gap between the actual and assumed cost of capital and MARs, since it was unable to quantify the full range of factors that could result in a MAR greater than 1.

We believe that the factors underlying Ofgem's decision to determine a cost of equity for DPCR4 at the upper end of the 6.5 – 7.5% range remain for DPCR5 given the continued investment focus in the sector and higher level of risk in the electricity distribution sector.

5.2.2 Cost of Debt

The allowed cost of debt is an extremely important element in ensuring DNOs can finance their functions. Access to the debt market is fundamental to our business model and Ofgem's cost of debt assumption must be sufficient to allow us to service our existing debt, raise new debt and refinance expired debt.

Essentially we believe Ofgem's statutory duty under Section 3(a)of the Electricity Act 1989 requires the making of a reasonably prudent estimate of the debt costs which efficient DNOs will incur through the next price control period.

We believe the use of debt indexation and/or debt triggers is not appropriate at DPCR5 because the DNOs are best placed to manage interest rate risk. It would not be in the interests of customers to shift this risk to customers, since this is likely to provide an incentive on the DNOs to be more risk adverse and encourage inefficient debt structures, thereby increasing the cost of debt. Indeed, we note that OFWAT have recently ruled out the use of index-linked debt in cost of capital calculations for UK water companies. Implementing such a scheme would also create an additional regulatory burden, involve undue intrusion in the financing structure of the DNOs and would need to overcome practical difficulties in determining what type of debt to include in any index. Provided the estimate of the cost of debt is set at an appropriate level at the price control review, both customers and shareholders share in the benefits of the current form of regulation. The CC firmly dismissed the use of debt indexation in the recent BAA review referral.

It is important to note that a DNO must have access to sufficient credit lines from banks to enter into the required interest rate swaps. A strong and stable investment grade credit rating is a key factor in securing the necessary bank credit lines. We will return to the issue of credit ratings later.

We welcome the increased transparency about Ofgem's current approach to setting the cost of debt (i.e. using the sum of an estimate of the equilibrium level of the risk-free rate and a ten-year trailing average of spreads on ten year term A/BBB UK utility bonds) and note the alternative proposal to use, for example, a ten-year trailing average of the yields of a suitable basket of utility bonds.

As Ofgem itself notes, the use of trailing averages would increase the risks to DNOs from inflections in the interest rate cycle. Given the severe adverse movements in the debt capital markets over the past nine months, we are naturally concerned that a trailing average rate will be skewed by the mainly favourable conditions in the past decade and will not fairly represent the actual borrowing costs in the next price control period.

We support an approach to calculating the cost of debt using a weighting of long, medium and short term debt to reflect the generic structure of an efficient DNO and the mix of refinancing typically experienced. This should allow for the historic profile of the debt, any fluctuations in interest rates and maintain a degree of consistency with previous price control assumptions. This approach would also reduce DNO exposure to maturity and refinancing risk and avoid customer exposure to market volatility over the control period.

The recent turmoil in the financial markets has implications for DPCR5, particularly in terms of the cost of debt and credit spreads. Recent trends in yields on A and BBB rated debt indicate that these are at the highest level seen in recent years. The trend since 1997 is shown in Appendix F2A. There is also strong evidence of a significant increase in credit spreads and that this will continue through DPCR5. Recent trends in credit spreads for ENW bonds and A and BBB rated debt are shown in Appendix F2B. DNOs are therefore likely to be carrying an additional credit spread burden during a period when they will need to raise new term debt.

The real cost of debt consists of a number of components and Ofgem needs to make full allowance for these components, including all transaction costs and fees. The cost of debt can be broken down into the following:

- the real risk free rate, as measured by index-linked gilts;
- the average spread over gilts;
- hedging costs;
- issue costs, including arrangement, utilisation, underwriting, legal and advisory fees;
- funding headroom; and
- embedded debt premium.

Each of these requires separate assessment before Ofgem can conclude on the cost of debt assumption.

In the past we believe there has only been a cursory consideration of the extra costs incurred by the companies in raising new and refinancing old debt. There are now clear regulatory precedents that the cost of debt should make allowance for both interest payments and associated fees. These can be in the form of commitment, agency and arrangement payments. This principle was established independently in 2000 in the CC decision on the Mid Kent and Sutton & East Surrey inquiries and more recently reinforced by both the CC and CAA in the BAA price review.

5.2.3 Gearing

Gearing needs to be set for the licensed distribution business, consistent with the regulatory ring-fence. Ofgem should maintain regulatory consistency with past decisions and provide an adequate equity buffer through the gearing assumption in the cost of capital. The CAA endorsed the CC recommendation in the BAA price review that 60% gearing achieves an acceptable balance between efficiency and resilience. It is important that the regulatory regime avoids creating uncertainty, which in itself increases the cost of capital.

The regulatory ring-fence around the regulated entity ensures that any debt issued by other entities in a corporate group (for example, by either other business units or by the holding company) will have no recourse to the regulated assets.

Assumptions that materially increase the level of gearing from that employed in DPCR4 will, in effect, force all companies to adopt similar structures. This stifles innovation and will not encourage the development of different business and financial structures.

We acknowledge that Ofgem needs to ensure that the risks of any higher gearing above the regulated entity do not transfer to the customer and we welcome Ofgem's recognition, in its conclusions to the Financing Networks Consultation, that the mechanisms to prevent this appear adequate.

5.2.4 Relative Risk

There can be other risks, not captured through the CAPM model, that need to be assessed at the price control. For example, there are risks associated with large capital programmes, as evidenced by recent regulatory decisions taken with regard to the building of the new terminal at Heathrow. At DPCR4 Ofgem recognised the relationship between rising investment levels and the cost of capital. These risks can manifest in cost overruns and input price increases.

There are other, equally important, areas of increased risks for DNOs, both since the last price control and when compared with other utilities. These risks need to be considered in modelling costs and revenues at the price control, allowing for the balance of risks and rewards built into the regime. For example, there would need to be an additional allowance at DPCR5, compared with DPCR4, for the increased risk associated with a move towards a more uncertain future in a dramatically changing energy landscape as discussed in earlier chapters of our response. We also believe that DNOs carry a higher asset risk when compared with Gas DNs for example.

We welcome Ofgem's decision to develop this issue as a workstream at DPCR5.

5.3 RAV

We are concerned that Ofgem may consider changing the current DPCR4 cost allocation rules that determine which costs are included in the RAV. This creates considerable regulatory uncertainty, increasing the cost of capital. Clear rules need to be applied on the type of expenditure that is eligible for inclusion in the RAV and these need to be applied consistently, otherwise confidence in the regulatory regime will diminish.

At the 2004 price review Ofgem removed a value for metering assets from the distribution RAV, thereby assuming that this residual asset value would be recovered in the competitive metering market. When these assets first entered the RAV it was assumed that they would be fully funded through subsequent distribution price controls. Removing the assets in this way creates uncertainty and is likely to lead to asset stranding and incomplete cost recovery. This is of particular concern as accelerated removal of metering assets as a result of the roll-out of smart meters increases the risk of asset stranding. We urge Ofgem to consider the treatment of legacy MAP as part of this review.

Ofgem has also tended to change the regulatory rules over price control periods, which has had the effect of creating uncertainty on the RAV approach. Ofgem has applied different rules on what expenditure enters the RAV from indirect costs and normalised controllable costs plus faults and have changed regulatory asset lives between price review periods.

5.4 Regulatory Depreciation

We believe that regulatory consistency is extremely important in this area and any instability in the assumption of regulatory depreciation lives should be avoided. Investor confidence will be severely damaged if the established remedy following the 'cliff face' in depreciation is not fully implemented and followed through.

At DPCR3 an adjustment was made to reduce depreciation lives to 20 years to overcome the severe effect of the depreciation cliff on cash flows for some of the DNOs. There were a number of principles established when depreciation lives were changed, including a 15-year smoothing adjustment to recover prior differences. This adjustment needs to run its course and this takes all DNOs beyond 2015. We believe the smoothing adjustment was made to stabilise the RAVs at the end of the smoothing period. Any attempt to reset depreciation lives would also introduce unnecessary complexity and uncertainty. We therefore believe it is important that Ofgem maintain the current 20-year depreciation life assumption for DPCR5 with a view to considering a long-term solution to depreciation lives as part of the Review of RPI-X at 20.

5.5 Taxation

We welcome the further planned discussion with Ofgem on tax issues and the modelling of tax allowances indicated in the consultation. To maintain transparency the tax model should be as simple as possible, whilst being fit for purpose. We support the intention to maintain consistency, wherever possible, with the approach used for DPCR4. However, there are examples where previous generic assumptions, such as the estimated live for deferred revenue expenditure, require reassessment at DPCR5.

Tax allowances need to be provided on a stand-alone basis, recognising that DNOs operate within different group structures. Allowances provided on an ex-ante basis are in the best interests of customers, incentivising companies to manage their tax affairs efficiently and optimising the benefits for customers at subsequent price controls. We would not support any approach that diminished the power of the incentive in this area. We do not believe that an ex-post adjustment for major changes in tax legislation should be introduced.

For consistency with other price control building blocks, tax allowances also need to be based on the notional gearing assumptions in the cost of capital.

The data being requested in the HLFBPQ in relation to related party capital expenditure is not only onerous to collate but also unlikely to have any significant impact on the overall tax charge. This is due to the fact that any capital allowances that Ofgem seek to include in the tax calculation would be matched by a similar adjustment for depreciation charges from the related party, which would have to be added back in the tax computation. We therefore propose that this data is not relevant.

It is in the interests of all stakeholders for Ofgem to adopt a simple approach to the tax treatment of incentives outside the main control. We welcome clarification that Ofgem is minded to quantity all incentives at their pre-tax value.

5.6 Pensions

We believe the consultation on pensions, planned for later in the year, will be an opportunity to debate a number of important developments in the pension area since the last price control. Whilst we would strongly assert that Ofgem must maintain consistency in preserving the principle of pas-through of efficiently incurred pension costs, there are a number of issues we will be keen to discuss such as:

- Pass through of additional pension costs incurred above allowance within DPCR4
- Changes to pension accounting.
- De-risking opportunities and investment strategies.
- Recognising statutory protections of benefits.
- Appropriate deficit recovery periods.
- The timing of actuarial valuations.
- Treatment of deficit recoveries under current accounting standards.
- Guidance provided by the pension regulator, e.g. mortality assumptions
- The balance of responsibilities between the DNOs and trustee bodies.

We recognise that these pension issues raise difficult challenges and would like to work with Ofgem to determine the best solutions.

5.7 Financeability

We require a strong credit rating to be able to finance our functions and this implies a long–term stable A3 credit rating. Although we have recently been downgraded to BBB+/Baa1, as is usual following a change of ownership, an A-/A3 rating remains our objective.

The financeability test at the price control needs to apply to all activities undertaken by the distribution business, including activities subject to separate controls and/or incentives, for example, DG and metering, and include the full effect of all known incentive mechanisms such as the capex roller. It also needs to extend beyond the five year price control period.

Ofgem needs to demonstrate that financial indicators remain comfortably within the boundaries to provide a buffer for any cost shocks. The price control proposals therefore need to be fully tested for potential cost shocks through a comprehensive sensitivity analysis. The interest rate used in the financial model in carrying out the financeability test needs to be consistent with the allowed cost of debt assumed in the cost of capital.

An appropriate credit rating is the primary factor that enables the DNOs to finance their functions over the price control period. Furthermore, prospects of future downgrades make it difficult to raise debt without a significant increase in the spread required, so stable ratings are needed to ensure adequate funding is available at reasonable rates.

Credit rating agencies interpret a basket of financial ratios and Ofgem need to maintain an ongoing dialog with the agencies on the types of indicators used and their current measurement. For example, some agencies assume that unfunded pension liabilities and environmental provisions may be treated as debt-like in nature. Consequently, actual credit ratings may be lower than implied by the stated debt figures in the accounts. Recent developments would indicate that RAV based gearing, FFO interest cover and increasingly post maintenance interest cover ratio (PMICR) are the most important indicators in assessing the credit worthiness of regulated utilities.

On the basis that DNO licences contain a requirement to maintain an investment grade credit rating then it is to the credit rating agencies that Ofgem effectively delegates the responsibility for close monitoring of a DNO's financial condition. It follows therefore, that Ofgem should fully engage with the credit rating agencies as to the use of these ratios when deciding if its price proposals will allow companies to maintain these ratings.

We believe the current pressures in the debt capital markets reinforce the need for Ofgem to target ratings which will allow "efficient" companies to finance their functions over a reasonable range of macroeconomic conditions by allowing some "margin for error" when targeting particular credit ratings in its financial modelling. We believe an approach of targeting a mid BBB rating generally accepted as the minimum requirement necessary to satisfy our licence obligations of "comfortably within investment grade", in Ofgem's financial model and financeability test, would be inconsistent with such an approach.

We also return to the issue raised in 5.2.2 in that the credit rating is a key factor in the DNOs maintaining access to credit lines for hedging interest rate costs and possibly currency-swaps where it may be necessary for the DNOs to access the Euro Bond markets to source an adequate depth of funding.

It is important that DNOs can continue to access efficient, long term sources of finance. Market capacity for different types of issuer is a key consideration at the price control. It is more appropriate in the electricity distribution sector to raise long term funding to match the life of the assets. In addition, long-term debt increases certainty, reduces refinancing risk and allows access to a broader investment base. There is a significant reduction in the investor base and available tenure of issues when credit ratings move down the BBB band towards the minimum investment grade threshold of BBB-. In particular long-term debt is much scarcer.

In recent years some utility companies have taken advantage of market conditions to issue indexed linked (IL) debt. However, this is a transient feature. The ability of DNO's to issue index-linked debt should not be assumed to continue at levels seen by UK utility companies in the 2006-2007 period. Demand for these issues was driven by two European investors with a particular investment horizon and was underpinned by the availability of monoline insurer credit "wraps". Two banks do not represent a deep and liquid market given the competing demands of UK regulated infrastructure companies with considerable funding needs. Further, the monoline insurance market has been largely wiped out as a result of the insurers' losses in the "sub-prime" market and several have lost their coveted "AAA" status. Therefore the availability of indexed linked debt as a source of funding has diminished considerably and no new debt of this type can be assumed for DPCR5. This finding is supported by Credit Suisse, advisors to the CAA on the recent BAA price review.

In an efficient market the total cost of indexed linked debt and fixed debt should be the same. Both add to a company's credit spread to the risk free rate but the fixed debt requires inflation to be paid annually, whilst the indexed linked debt accrues this to a payment at maturity. Differences in actual yields arise from movements in actual RPI versus the assumed inflation rate. This inflation risk is best managed by the DNOs that naturally seek out an efficient capital structure, rather than passing this risk onto customers, which would lead to DNOs becoming more risk adverse and hence adopting less efficient structures.

An alternative to index-linked debt are "synthetic" structures combining a conventional fixed rate bond with an index-linked swap. IL swaps are extremely credit intensive for the counter-party bank and here again, strong investment credit ratings will be crucial to maintain access to this funding, which arguably best aligns the DNO's income to debt costs.

It is important for Ofgem to set a realistic dividend yield assumption when applying the financeability test. This needs to be set at a level that would attract and retain such investment, reflecting the returns expected by the investors. Adjusting the dividend assumption by assuming a proportion of retained profits would not necessarily be consistent with investor expectations.

Revenue profiling can be a legitimate tool to solve financeability issues. However, it has to be recognised that this can change the pattern of prices for customers and it is sensible to choose a profile that provides some stability and that can be more easily explained to customers.

It is important to recognise the impact of changes in accounting standards on the financial statements of the DNOs, which can have implications for some of the price control building blocks, e.g. tax, and potentially impact on credit ratings. If not accounted for adequately these changes increase risk on the DNOs.

5.8 Excluded Service

We believe it is appropriate for Ofgem to consider alternatives to the approach adopted in the past to excluded services.

In the past Ofgem has tended to forecast 'other excluded services' revenue using historic information and the levels being experienced. This has then formed the basis of the projected allowance. Annual variations to the allowance are captured and adjusted through the RRP. A consequence of deducting all additional revenues over and above the price control assumption is to provide a powerful incentive for DNOs not to carry out work in these areas. There is little point in providing additional services to suppliers and other customers in the excluded services area, only to find there is a blanket approach in the RRP that removes any margins earned.

A variant to the above approach would be for Ofgem to adopt an averaging approach to calculating the forecast revenues from other excluded services. Customers benefit from the increasing levels of revenue assumed at each price control. If Ofgem were to apply a weighted industry average forecast then those DNOs with above average revenues would have an incentive to maintain their high levels and laggard DNOs would be encouraged to increase activity to generate more revenues. These extra revenues would be observed and captured at subsequent price controls for the benefit of DUoS customers. This would remove the need to make subsequent adjustments through the RRP.

As regulatory reporting matures and the size of the distribution business shrinks, as a result of regulatory unbundling, consideration should also be given as to whether the threshold on de-minimis activities should be increased to ensure that the headroom provided is sufficient to enable DNOs to undertake new activities.

5.9 Financial Model

In the interest of transparency it is important that Ofgem discusses the financial model they will use to set the price control early with the DNOs. It would be very unhelpful for DNOs to make their submissions at the price control review using a different model from Ofgem, since discussion would revert to differences in model logic, rather than the more important focus on key assumptions at that stage.

Appendix F1 – Answers to specific questions in Financing Chapter

Question 1: Should Ofgem use its traditional approach to calculate the cost of capital or should other approaches be considered in order to provide the necessary incentives to invest?

Ofgem should continue with its traditional approach to calculating the cost of capital, recognising the changes in the risk profile of the DNOs and supplemented with appropriate incentives to invest. The assessed cost of capital sets the minimum allowed return in the price control building blocks but this may need to be increased, for example, as an incentive to encourage investment.

Question 2: In particular, should measures to protect DNOs from debt market volatility be considered, such as indexation of the cost of debt, or the use of reopeners at "trigger" levels of interest rates?

No. The use of indexation and/or debt triggers would shift the risk profile to customers, making DNOs more risk adverse and increasing the cost of debt. The DNOs are best placed to manage interest rate risk through their treasury management activity. A guiding principle is that risk should be allocated to the party that is best able to manage it. We note that the Competition Commission supported this principle in their decision on the BAA review and concluded that it could not recommend automatic adjustments to the cost of debt.

Question 3: Should Ofgem make financeability adjustments or is this a matter for DNOs once the cost of capital is set?

Ofgem need to demonstrate that their final proposals for DPCR5 are financeable. This necessitates Ofgem making appropriate financeability adjustments if required. The financeability test must be made following the approach of the major credit rating agencies. This needs to take account of investor expectations and the requirement for strong credit ratings in the current financial climate.

Question 4: Is it appropriate for Ofgem to be making commitments on investment and its financeability over the longer term?

It is extremely important for Ofgem to make commitments on investment and how this is funded to match the long-term nature of the underlying electricity distribution assets and investor expectations. Stability within a long-term financial framework is crucial. Investor confidence is severely damaged if there is a lack of regulatory commitment that increases risk and uncertainty in this area. This requires a commitment to the RAV both in terms of the rules determining the allowances at the price control and the application in terms of rolling forward the RAV between price controls.

Question 5: Should a mechanism for ex-post adjustments for major changes in the tax regime be introduced and, if so, how?

Tax allowances provided on an ex-ante basis are in the best interests of customers, incentivising companies to manage their tax affairs efficiently and optimising the benefits for customers at subsequent price controls. We would not support any approach that diminished the power of the incentive in this area. We do not believe that an ex-post adjustment for major changes in tax legislation should be introduced.

Question 6: Do respondents support the publication of a fully populated financial model?

Selective data for individual DNOs should be published in the proposals documents, similar to DPCR4. However, because of commercial confidentiality, only aggregate industry data should be published in the form of the full financial model. This approach would provide interested parties with an understanding of the workings of the financial model without compromising the confidentiality of some of the individual DNO data.

Question 7: Should we calculate the DNOs' allowed revenues in a way that creates a smooth revenue profile over the course of the price control period and seek to reflect the level of costs expected in the last year of the control in order to reduce price changes from one control to another?

Although it is helpful to aim to provide a degree of price stability for customers, it is paramount that the profile of revenues demonstrates that the final price control proposals are based on a financeable plan. This may result in a profile of price changes that requires a step change at the beginning of the next price control.

Question 8: What factors should we take into account when determining the level of gearing to assume?

It is important that there is a degree of consistency in the gearing assumption across price controls and that there is an adequate equity buffer so that higher gearing does not transfer unwarranted risk to consumers. Uncertainty surrounding a key cost of capital assumption, such as gearing, has an adverse effect that is not in the best interests of the DNOs or customers.

At the price control, the gearing assumption needs to be set in relation to the regulated distribution business, consistent with an assessment of the appropriate level of financial risk borne by the regulated business. Whether debt increases the financial risk borne by the regulated business is determined by whether debt holders have recourse to the assets of the regulated business. The presence of the regulatory ring fence around the regulated assets ensures that any debt issued by other entities in the corporate group structure do not have any recourse to the regulated assets.

Question 9: Do respondents agree with the proposed treatment of net debt and gearing in ex post adjustments to tax allowances?

We understand Ofgem's desire to discourage the regulated businesses from adopting highly geared structures. However, there are practical difficulties with implementing this approach, which we would like to discuss and would hope that clear guidance could follow on how any adjustment would be made.

Question 10: What are acceptable alternative approaches to calculating RAV additions; and, following recent market transactions, does RAV continue to reflect the underlying enterprise value of the business?

RAV additions need to be calculated under a framework that provides clarity and consistency to maintain investor confidence in the regulatory regime. Relatively small changes in the approach to the RAV can have dramatic effects on DNO revenues. We welcome the Review of RPI-X at 20 that needs to consider the use of the RAV in price controls.

There are several reasons why the RAV does not reflect the underlying enterprise value of the business. For example, the enterprise value includes non-distribution assets and captures any out-performance against the regulatory contract.

Question 11: We are interested in obtaining views on how, if at all, we should take account of MARs in setting the cost of capital?

It is difficult to separate out any effect of changes to MARs on the cost of capital. We believe that the recent premia paid for regulated utilities has been driven by excess demand for index linked income streams and this does not imply anything for the real cost of equity.

There are several factors, other than the cost of capital, that justify companies paying premia to RAV including:

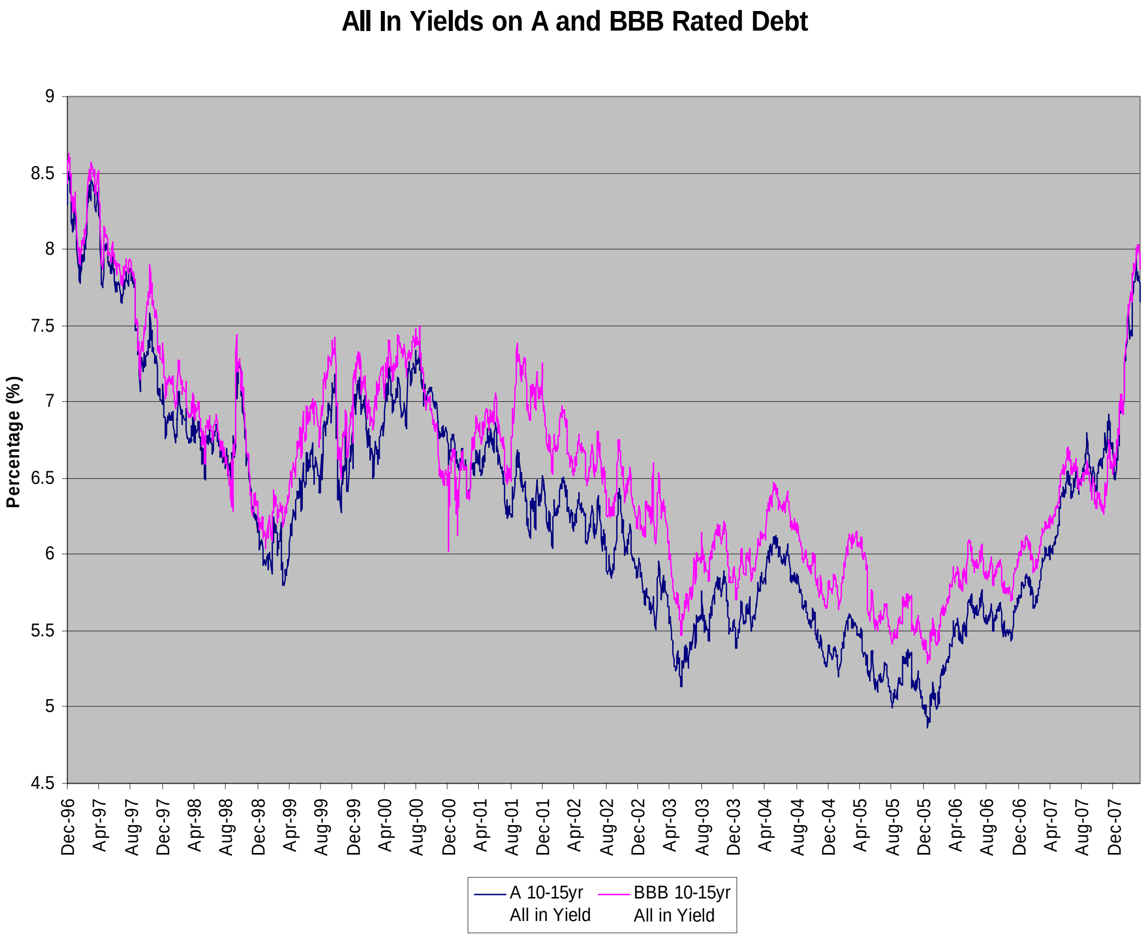
- expected RAV growth;
- any instability in the way costs enter the RAV, which can diverge from investor expectations;
- outperformance against the regulatory allowances; and
- incentives outside the price control.

Previous attempts to use MARs to directly estimate a company's cost of capital have been flawed. The CC concluded in its work on the BAA review that it was unable to draw any conclusions about the gap between the actual and assumed cost of capital and MARs, since it was unable to quantify the full range of factors that could result in a MAR greater than 1.

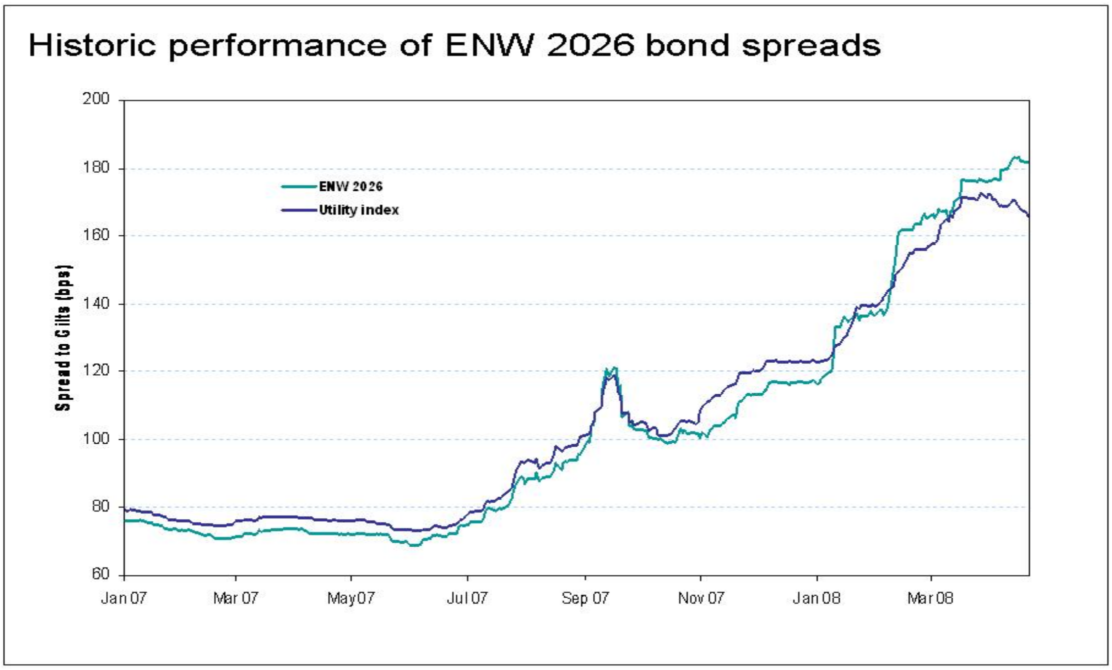
Question 12: Are depreciation adjustments to accelerate cashflows appropriate and are they sustainable to meet our financeability goals over the long-term?

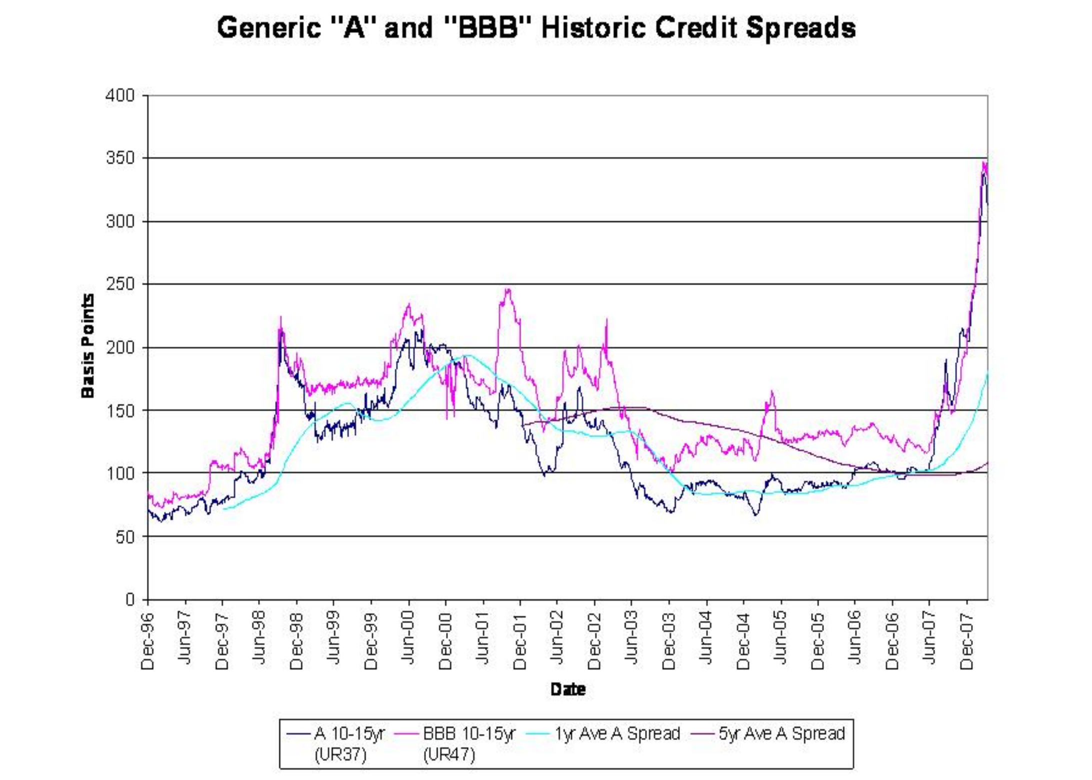
The tilting of depreciation was first applied in DPCR3 and was necessary to overcome severe cashflow difficulties for those DNOs affected by the depreciation 'cliff-face'. There were a number of principles established when depreciation lives were changed, including a 15-year smoothing adjustment to recover prior differences. This adjustment needs to run its course and the RAV needs to stabilise. This takes all DNOs beyond 2015. We therefore believe it is important that Ofgem maintains the current 20-year depreciation life assumption and smoothing adjustment for DPCR5. The longer-term issue of the sustainability of this depreciation assumption should be considered as part of the Review of RPI-X at 20.

Appendix F2A



Appendix F2B





Source: HSBC

Chapter 6 - Process

We welcome Ofgem's indication that DPCR5 will be a transparent process and their intention to provide longer consultation periods and meetings with interested stakeholders. We support Ofgem's intention to learn from DPCR4 review and incorporate the best features of that process and the recent GDPCR process. We also welcome the proposed DNO working groups. The greater consultation periods should be cognisant of the reality that it takes a considerable time to produce data which may often include the need to liaise with other DNOs regarding a data request. Therefore, it is important in particular that details of exactly what will be required at each submission are published early and that the proposed publication of the Ofgem financial model is earlier in the proposed timetable than currently suggested.

We have explained recently to Ofgem representatives how our own stakeholder engagement for DPCR5 will work and our initial workshop for regional stakeholders in Manchester on 10 April was well received by attendees. However, in Ofgem's context, it is important to recognise that different stakeholders will be seeking different results from DPCR5 and that greater stakeholder engagement will raise the expectations of some stakeholders. It is imperative that Ofgem and DNOs are able to manage those expectations as a failure could lead to dissatisfied stakeholders and a lack of trust in the process for the future.

Ofgem's proposed timetable has raised a number of points, in particular:

- There appears to be repetition in March, June, July and August 2009 of "forecast data". We would like to have more clarity on these requests and what these submissions would be intended to achieve. Such clarity would allow for better planning. For example, it would be helpful to understand how these various submissions will interact with the IQI base case assessment.
- We recommend that Ofgem consider the inclusion of a September update, or at the very least publish an update letter between the initial and final proposals. Such a document would allow any developments in thinking to be transparent.
- We welcome the proposal to publish draft licence modifications with the initial proposals as this would remove some potential ambiguity.
- It is essential that Ofgem's financial model is made available much earlier in the price control process than is currently proposed.

Appendix P1 - Answers to specific questions in Process Chapter

Question 1: Do you agree with the range of consultation approaches we intend to use throughout DPCR5?

We generally support the range of proposed consultation approaches. We recommend the addition of a further consultation to be issued between the initial and final proposals.

Question 2: Do you believe that we should utilise a consumer orientated challenge group to inform DPCR5?

We note and support the announcement of such a consumer panel on 14 May. The composition of such a group is important; in particular it should be proportionate and representative of regional views. The group should have a good understanding of what customers are willing to pay for and take an unbiased opinion/judgement

Question 4: Are there any other ways in which we should look to consult with interested parties?

We cannot suggest any other ways.

Question 5: Do you agree with our approach to publish specific impact assessments for key "important" decisions?

We support Ofgem's intention to publish specific impact assessments.

Question 6: Are there any other key milestones that you believe we should consider for DPCR5?

We recommend the inclusion of a September 2009 consultation or update letter.

The time between publication of the December 08 policy paper and the January 09 submission of the FBPQ is short (and includes Christmas holiday period). This will give DNOs very limited time to make any necessary changes or to consult with stakeholders.

Ofgem should include any implications from the Energy Bill/Act 2008 within their timetable, recognising the influence that these decisions may have on DNOs' future role.

We seek greater clarity as to what is involved with each of the RRP/FBPQ submissions that are linked together and will often be compiled by the same staff within DNOs.