



**Electricity Distribution Price Control Review (DPCR5)  
Policy Paper**

**Electricity North West Response**

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#### **Note on Layout**

Our response to the Ofgem Policy Paper follows the framework set out in the original consultation. The document is prefaced with an executive summary.

The first sub-section of each chapter contains a summary of the detailed responses contained within the chapter. Answers to Ofgem's specific questions are contained within the body of each chapter but are summarised with cross references in the second sub-section of each chapter for ease of reference. The specific questions within Chapter 1 are addressed in the appropriate sections of the following chapters.

# Electricity Distribution Price Control Review (DPCR5)

## Policy Paper

### Electricity North West Response

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**1 Executive Summary**

DPCR5 is being conducted at the height of the “worst economic crisis for decades” and against the backdrop of a global recession. The DPCR5 settlement will need to reflect the prevailing economic conditions, recognising that the level of uncertainty and risk borne by customers, investors and stakeholders has increased significantly. Ofgem’s first challenge in DPCR5 is to promote confidence and reassure customers and investors. In addition to the global economic crisis, we also face unparalleled environmental challenges. We recognise that DNOs have a significant role to play in the movement to a low carbon economy and must minimise their own impact upon the environment.

Our customers want us to ensure that we maintain the quality and security of supply they have enjoyed in recent years and that the number of customers exposed to the worst performance reduces. They appreciate the improvements we have made to the way we interact when they have to contact us. In difficult economic times they want us to remain focussed on controlling costs to deliver the lowest sustainable prices.

Government and other stakeholders want us to continue to invest in our vital infrastructure, play a full part in facilitating the move to a low carbon economy and ensure that we have long-term security of supply.

Building these factors on to the investment requirements of our ageing asset base, we like many other DNOs, must make a significant increase in investment in DPCR5. Consequently, we need to be confident that expenditure will be recoverable and that finance is available and affordable. There is a strong message within the Policy Paper that DNOs will be required to change, to innovate and to take on more risk. Innovation is certainly required if we are to meet the twin challenges, of dealing with the economic crisis and moving towards a low carbon economy, simultaneously. However, customers should not be expected to pay too heavy a price for these developments because the financial markets lose confidence in the regulatory regime. Ofgem must find the right balance between making the necessary changes to address the immediate issues caused by the economic circumstances and, where possible, continuing the refinement of the price control mechanisms and the wider regulatory framework.

To meet the needs of our customers and other key stakeholders we need to develop a regulatory framework that acknowledges the full extent of the investment programme we must undertake. The DPCR5 price control must recognise that the DNOs require significant levels of financing from the investment communities to deliver the proposed outputs. Whilst the utilities sector has been viewed as a reasonably low risk investment in the past and attracted comparatively low interest rates, the current circumstances have already resulted in higher financing costs, more restrictive debt covenants and more caution from debt rating agencies, a situation which is likely to continue for the foreseeable future. The DPCR5 price control must encourage equity investors by giving the reassurance that should the costs of new debt be greater than assumed in

the price control settlement, a mechanism exists for Ofgem to fund these costs, where companies have acted appropriately. This approach can also protect customers from the risk of over compensating DNOs, should debt costs fall more quickly than expected.

To ensure that this investment is delivered efficiently, protecting prices for customers in the medium to long term, the broad incentive properties of the price control must be maintained. The equalisation of the operating and capital expenditure incentives will allow the DNOs to focus on managing the network for customers at the lowest whole life cost. The equalisation will also make employment of Demand Side Management schemes a realistic possible alternative to reinforcement capex investment. Fixing the proportion of costs which enter the RAV will create this equalisation and remove the issue of boundaries between cost categories, but will require more attention from Ofgem to ensure that DNO's minimum cash requirements are met.

As a result of DNOs responses to effective regulatory incentives, customers in Great Britain now enjoy very high security and quality of supply standards and the continuation of the Interruptions Incentives Scheme should be focussed on perpetuating these benefits.

The UK has not witnessed the expected level of distributed generation forecast at the start of DPCR4 for a range of reasons and DNOs cannot be held accountable for the lack of progress in this area considering the explicitly passive role which Ofgem prescribed for them at DPCR4. The DG incentive should be retained as the means to set a DNO's allowed revenue from generation customers. However, the regulatory framework needs to evolve to allow the network companies to promote and encourage further DG development and connection. Ofgem have the opportunity to remove a number of regulatory barriers to the further development of environmental best practice in DPCR5, specifically the units distributed revenue driver, the equalisation of opex and capex incentives and merging the demand and generation revenue into one single charging methodology. This final development will enable demand to credit generation where it truly defers network reinforcement investment.

We also see the proposed innovation incentive as crucial in bringing forward innovative technical and commercial solutions to DG issues. The regulatory framework must encourage innovation by providing a stable platform that gives DNOs the confidence to try new things. In this regard Ofgem should make clear that price control framework supports ENW's development of an innovative new business model as soon as possible and confirm that margins earned by our service provider (UUES) will not be disallowed in DPCR5.

Two important evolutions in the regulatory framework are the development of a model of regulatory returns (RORE) and the commitment from DNOs to specific output measures. The application of RORE and outputs should help to demonstrate to customers that DNOs are maintaining the efficiency of their operations; exhibiting the positive behaviours that improve service; and delivering the investment to meet network requirements and manage risk. The utilisation of an outputs based approach will allow the DNOs to submit plans to Ofgem which reflect the actual needs of their customers, stakeholders and their networks, with a clearer understanding of the risks DNOs are being asked to manage and the measures DNOs will deliver for customers.

## **2 Environmental Issues**

### **2.1 Chapter Summary**

We are fully committed to our role in achieving a low carbon future, both as a facilitator on behalf of other market players, and in terms of reducing the environmental impact of our own activities.

We do not accept Ofgem's implied criticism of the DNOs' role to date in countering climate change. We have engaged in discussions on environmental issues to the fullest extent reasonable, and have responded positively to the relevant incentives placed upon us. Equally, we do not expect any DNO to pay for pre-emptive action where there is no confidence of cost recovery.

Going forward however, we recognise that the long term benefits to consumers of actions now to support renewables are potentially significant and may warrant a change in the risk/reward balance and a consequential expansion of the DNO role over time. In order to achieve this "next level" in terms of environmental issues requires adjustment of the regulatory framework to support the change in focus.

For DPCR5, we see the following as essential elements of the regulatory framework:

- Consistency and stability where appropriate
- Removal of perverse or confusing elements of the regulatory framework, particularly relating to DG and DSM.
- Clarity on how DNOs will be rewarded for taking increased levels of risk.
- A broadly scoped and flexible approach to innovation.
- Continuing engagement.
- Acknowledgement of the attendant risks of climate change impacts and recognition of the need for adaptation investment.

#### **2.1.1 Future Uncertainties**

We recognise the need for DNOs to think strategically but do not accept that this is anything new, as Ofgem seem to suggest. Since privatisation DNOs have halved their work forces, halved their costs and doubled the quality of supply enjoyed by customers. This performance is direct evidence of real strength in strategic and innovative thinking and implementation. It is not the case that a step change in DNO thinking is required; we point to past examples of engagement with environmental developments, what we need now is the right commercial environment and regulatory framework (as well as customer demands) in order to foster further development.

We see the DNO role as moving from the simple "removal of barriers", through the introduction of innovation towards a point where increased risk reward profiles are introduced into defined areas of DNO investment. Therefore, alongside "traditional" incentive schemes we see an increasing role for the proposed innovation incentive scheme, operating on a project-by-project basis. We see this as working in situations where customers/society could benefit by an innovative development to sufficient

extent that the DNO could take a greater level of risk than has recently been the case for utility networks, encouraged by specifically targeted cost recovery mechanisms.

### **2.1.2 Distributed Generation**

The major constraints on DG development in our area to date have not been network-related; however despite this background we have continued to develop our own contributions to the facilitation of DG and give examples of these.

The DG incentive is fit for purpose in terms of driving behaviours; it was not designed to drive volume. We welcome consistency and continuity in this area and agree that that the structure of the DG incentive should be retained as the means to set a DNO's allowed revenue from generation customers.

For the future we are concerned that there are aspects of the current regulatory framework and the incentives on DNOs that if left unchanged would restrict our ability to innovate to facilitate DG. We have identified significant features of the regulatory framework that need to be addressed in order to provide clearer investment signals in this area, in particular the removal of the kWh based revenue driver, the equalisation of opex and capex incentives and the extension of the scope of the innovation incentive to technical and commercial solutions on real networks.

### **2.1.3 Innovation and Future Networks**

Our response to the specific issues raised is summarised below:

- We agree with the discontinuation of the RPZ scheme.
- We are fully committed to the IFI. ENW is the only DNO that has utilised its full allowance, and has plans to continue such expenditure in DPCR5.
- We welcome a more broadly defined innovation mechanism or incentive to encourage technical and commercial innovation in real network examples.
- We are unlikely to place project proposals in the FB PQ for ex-ante funding (Ofgem's Option 1). We suggest that DNOs make proposals to Ofgem after the FB PQ **and** during DPCR5 (not just during DPCR5 as suggested in Option 2)
- We support Option 2, and particularly welcome commercial innovation being in scope. We see potential for a range of projects, and intend to highlight the issue of getting significant generation connected in Cumbria.
- We reject the post-period discretionary reward/penalty (Option 3) as we can not build a business case on discretionary reward, and we view discretionary penalty as an arbitrary increase in risk.

### **2.1.4 Transmission Exit Charges**

We are concerned that the introduction of an incentive on transmission grid exit charges would introduce risks which are not within ENW control, since the charges are demonstrably volatile and a large proportion relates to the refurbishment of existing capacity rather than the installation of new capacity to satisfy DNO requirements. We do not believe that an incentive is necessary since the prices have already been regulated in the TPCR and despite the absence of a direct incentive, we can point to

several examples of how ENW proactively maintain the commercial aspects of exit charges on behalf of our DUoS customers.

### **2.1.5 Losses**

We recognise the significance of losses in terms of DNOs' own carbon footprint; however we believe that the current mechanism for incentivising loss reductions does not give sufficiently clear investment signals, and we propose a more focused incentive in its place.

Our concerns regarding the existing losses mechanism continue to relate to the significant data measurement issues and the limited control that the DNO can exercise over the losses measure as currently defined. We support the introduction of an input-based incentive regime, targeting individual loss reduction initiatives.

Given that an incentive of some form is appropriate, we support an enhancement of the rate (to include the Shadow Price of Carbon) in order to drive investment

If the existing mechanism is used however, an increased rate should be associated with the introduction of caps and collars. Also, the target should be set on 10 years history (rather than 5 years or less) to overcome settlement related volatility. Volatility effects could be further mitigated by the use of five-year rolling totals in place of in-year "actuals" when setting targets.

### **2.1.6 DNO Business Carbon Footprint (and SF<sub>6</sub>)**

We welcome Ofgem's approach to developing a common approach to carbon footprint measurement (including SF<sub>6</sub>) and note that the format substantially reflects our own 2007/08 carbon footprint report, previously copied to Ofgem.

### **2.1.7 Undergrounding in AONB**

The overall quantum proposed for ENW does not appear inappropriate, and is broadly in line with our current plans. We suggest that the cost caps are removed entirely such that high scenic quality but expensive schemes are permissible.

### **2.1.8 Fluid Filled Cables**

We support the continued development of an industry standard risk-based approach to targeting the replacement of fluid filled cables, and support investment in the development of new technologies to detect leaks.

## **2.2 Answers to Ofgem's Specific Questions**

**Question 1: Do you agree with our view of future uncertainties and the need for DNOs to change their way of working and thinking to encompass innovation and flexibility?**

See section 2.4 of our response.

**Question 2: What are your views on our proposals for DNOs to provide more information to help low carbon initiatives and have we adequately identified and defined the information requirements?**

See section 2.5.3 of our response.

**Question 3: Do you agree with our proposal that all distributed generation should pay use of system charges, and if not, can you provide evidence to substantiate your specific concerns?**

See section 2.5.5 of our response.

**Question 4: Do you agree that the distributed generation (DG) incentive should be retained? Should embedded transmission be deemed relevant DG?**

See section 2.5.6 of our response.

**Question 5: What are your views on our proposals on innovation and flexibility? How would you rate their feasibility and which option is most likely to drive the more innovative and flexible behaviour that we are seeking?**

See section 2.6 of our response.

**Question 6: What are your views on our proposal to set an incentive on transmission grid exit charges?**

See section 2.7 of our response.

**Question 7: What are your views on our losses proposals, and do you have any additional comments on the option to install smart meters on low voltage substations?**

See section 2.8 of our response.

**Question 8: What are your views on the various aspects of the business carbon footprint proposals?**

See sections 2.9 and 2.10 of our response.

**Question 9: What are your views on our proposals for refining the undergrounding scheme? In particular, should we apply caps per km of cable by voltage level or should we remove all voltage caps and just have a single overall cap?**

See section 2.11 of our response.

**Question 10: Do you agree with our proposed approach for the treatment of fluid filled cables?**

See section 2.12 of our response.

### 2.3 Background (2.1 – 2.9)

We are fully committed to our role in achieving a low carbon future, both as a facilitator on behalf of other market players, and in terms of reducing the environmental impact of our own activities.

We do not accept Ofgem's implied criticism of the DNOs' role to date in countering climate change. We have engaged in environmental issues to the fullest extent reasonable, and have responded positively to the relevant incentives such as those for DG and IFI. It must be remembered that Ofgem, until recently, have made it clear that they see network development, at both the transmission and distribution levels, being driven by customers, rather than by the network companies themselves, which is perhaps not inappropriate at such an early stage of market development. Equally, DNOs will not pay for pre-emptive action where there is no confidence in cost recovery. It is not sensible or appropriate for DNOs to take all the risk of early investment and then have their efforts judged with the benefit of 20:20 hindsight.

Going forward however, we can recognise that the long term benefits to consumers of actions now to support renewables are potentially significant and may warrant a change in the risk/reward balance and a consequential expansion of the DNO role over time. In order to achieve this "next level" in terms of environmental issues requires an assessment of the objectives and adjustment of the regulatory framework to support the change in focus.

A significant issue at this stage is the uncertainty over how environmental issues will translate into network requirements. We agree that the environmental agenda will drive massive changes to the energy industry, but the exact nature and timing of the changes and their impact on the operations of the DNOs are far from clear. It is inevitable that uncertainty will persist in the absence of clear policy direction and significant reliance on market solutions to environmental issues.

The additional risk associated with new investment related to climate change issues needs to be coupled with the significant reward that would accrue to customers over the long term. We see a development over time whereby this relationship becomes better understood, and crystallised in a form that can be shared appropriately between customers and DNOs.

For DPCR5, we see the following as essential elements of the regulatory framework:

- Consistency and stability where appropriate
  - We see the current DG incentive as providing the correct allocation of price and volume risk and believe that it should continue in its present form. Additionally however there is a need to remove perverse or confusing investment signals such as the kWh revenue driver, and the imbalance of treatment between capex and opex in order for the incentive to operate to its fullest extent.
- Removal of perverse or confusing elements of the regulatory framework, particularly relating to DG and DSM.
  - Remove the kWh Revenue Driver, to remove the clear disincentive to connect generation that offsets demand.

- Equalisation of the Opex and Capex incentives, to encourage further consideration of non-asset-based solutions.
- Confirm the merging of DUoS revenues, so that all DG incentive rewards are shared appropriately across the wider customer base.
- Clarity on how DNOs will be rewarded for taking increased levels of risk.
  - Well structured incentives, providing commercially attractive propositions where risk is balanced by attractive levels of potential reward.
  - Recognition that costs need to be covered where risks are not shared
- A broadly scoped and flexible approach to innovation.
  - Provide opportunity for innovatory mechanisms to be tested throughout DPCR5.
  - Innovation incentives broadened to DG/DSM/storage and to include commercial arrangements
  - Potential new roles, eg in heat networks, funding mechanism for smart metering, or as agent for DG, funding and administration of feed-in tariffs
- Continuing engagement.
  - We believe that the Undergrounding scheme and the ongoing development of Carbon Footprint measures are good examples of how collaborative discussions have led to the creation of effective and appropriate frameworks.
  - We look forward to continuing collaboration, in particular in the context of the innovation scheme.
- Acknowledgement of the attendant risks of climate change impacts and recognition of the need for adaptation investment, eg flood defences etc.

## **2.4 Future Uncertainties (2.10 – 2.21)**

### **2.4.1 Ofgem's view of future uncertainties**

We agree with Ofgem's assessment that significant uncertainties exist in the shape of the low-carbon economy, speed of development and detailed impacts on DNOs. Ofgem's LENS work, supported by DNOs, demonstrates this wide range of approaches in the long-term to 2050.

We have undertaken detailed work on understanding the drivers and constraints on DG connections in our area, including discussions with many regional stakeholders. Despite this investment of our own resources in understanding this area, we still consider that there is significant uncertainty in our DG forecasts. Definition of reliable volume outputs is difficult for DG because of fundamental issues outside the DNOs' control which affect DG volumes, not because of poor management by DNOs. Developers will initially cherry-pick low-connection-cost DG projects, thus depressing the £/kW figures for reinforcement and connection costs. Given this background, DG connections should not form part of the IQL.

We agree that the policies outlined in Figure 2.1 show the potential changes in use of network in the timescale to 2020. We recognise Ofgem's acknowledgement that the figure is highly simplified; however it is important to stress that the description of the

policies does not convey how all the measures will be deployed in a lumpy site-specific way (dependent on local economic, development and resource factors), rather than some kind of smooth and even change of direction across a DNO area or between DNOs.

We comment more on the future uncertainties and incentives in Sections 2.5 (Distributed Generation) and 2.6 (Innovation and Future Networks) below.

#### **2.4.2 Evidence of ENW engagement**

We disagree with the negative statement that “DNOs have not been proactive in liaising with relevant bodies”. This section provides evidence of how we have been acting positively to engage in environmental policy issues. Against the background of acknowledged uncertainty, it would be unreasonable to expect that we could be more forthright on policy.

- Our detailed policy review behind our forecasts of DG growth.
- Detailed assistance to the North West Regional Assembly’s project to develop an evidence-base for their assessment of renewable resource potential, contributing to the development of regional planning policy.
- Ongoing liaison with Association of Greater Manchester Authorities (AGMA) and West Lakes Renaissance (WLR) in a number of areas.
- Working with Friends of the Lake District on identifying projects for undergrounding for visual amenity. The regular contact with this stakeholder has provided opportunity to also discuss DG connection issues.
- In DPCR3, prior to the introduction of the DG incentive, we took the step of advertising nationally to draw attention to the availability of spare network capacity for generation in Cumbria following the closure of Calder Hall.
- We are currently engaged in an early pilot project with large industrial customers in Buxton to investigate the possibilities of a practical DSM scheme to obviate Ashwood Dale primary substation reinforcement.
- A systematic interview programme with regional stakeholders and developers to raise awareness and understand expectations of ENW.
- Stakeholder engagement workshops during 2008 as part of our DPCR5 preparations, including preparation of our Strategic Direction Statement.
- Contribution to the individual work-streams of the national Distributed Generation Co-ordinating Group
- Support of the BERR-funded project to develop a toolkit to include sustainability issues in decision-making.
- Contribution to the individual work-streams of the national Distribution Working Group (DWG), under the ENSG. DTI/BERR invited industry involvement in addressing technical and commercial barriers under the ENSG/DWG. ENW has supported these working groups over the last few years, but in contrast to the positive engagement of the DNO representatives, DTI/BERR then repeatedly withdrew and delayed funding for key projects.
- 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. We initiated and promoted this review of these documents, and are strongly promoting the position that DNOs should review

their insistence on the costly and blanket application of Neutral Voltage Displacement protection for small LV connected generation.

- CAP167. The England and Wales DNOs, together with Modification Working Group, have been working hard to ensure that any CUSC changes are appropriate. DNOs in particular have been concerned about the potential increase in the barriers to DG as a result of an increase in the volume of Small Embedded Power Stations requiring a request to National Grid for a Statement of Works. We have been actively involved in the Working Group and engaged in these wider industry developments and as such we are pushing hard for proportionate solutions.

### **2.4.3 Do DNOs need to change their way of working?**

We recognise the need for DNOs to think strategically but do not accept that this is anything new, as Ofgem seem to suggest. It is not a case of a step change in DNO thinking being required; we can point to past examples of innovation and business change, and what we need now is the right commercial environment and regulatory framework (as well as customer demands) in order to foster further development.

We strongly reject Ofgem's implication that currently DNOs are not innovative and flexible. We are keen to play our full role in supporting the UK's transition to a low-carbon economy, and throughout this response we give evidence of our engagement as a DNO on national and regional policy and of our past innovations. These actions are generally linked to the existence of appropriate incentives. We have responded rationally to the strong regulatory framework, put in place to ensure risk is minimised in a utility function of national importance.

We have a strong commercial and strategic desire to change and expand the DNO role over time. Whilst we understand that this requires changes in the regulatory framework to enable such a transition, we are not waiting for such changes to be developed by others. We are proactively exploring a number of initiatives that may yield fruitful developments and we are actively engaged in a wide range of industry and stakeholder dialogues, including this policy paper response, where we are developing and proposing the changes required.

We see the DNO role as moving from the simple "removal of barriers", through the introduction of innovation towards a point where increased risk reward profiles are introduced into defined areas of DNO investment. Therefore, alongside "traditional" incentive schemes (which rely on full measurability and controllability of the objective function) we see an increasing role for the proposed innovation incentive scheme, operating on a project-by-project basis. We see this as working in situations where customers/society could benefit by an innovative development to sufficient extent that the DNO could take a greater level of risk in return for greater share of the reward.

There are two key factors which currently constrain the influence of DNOs over progress towards a low carbon future:

- Development of renewables and CHP connections have been constrained by aspects outside the DNOs' control; specifically funding, planning, transmission access and installer/equipment supply chain. The Supplier Hub principle

diminishes and frustrates DNOs' ability to engage with customers and generation developers.

- The regulatory framework in place for DNOs has promoted a cautious approach otherwise DNOs are faced with actual or threatened financial penalty. This is consistent with a low overall cost of capital. The introduction of IFI and the DG incentive were welcome steps in the right direction, but insufficient for the scale of potential change.

We believe that the focus must now be on adapting the regulatory framework, both in terms of removing barriers imposed and also on developing incentives which are sufficiently flexible to accommodate a developing role for DNOs in the longer term.

In setting incentives in order to drive DNO behaviours, we need to have a common understanding of what is meant by 'facilitation'; specifically whether DNOs are driving growth or facilitating growth? 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
  - We do not believe that it is the role of the DNOs to cross subsidise any particular customer group; we will act commercially, within the terms of our licence, given the regulatory and commercial incentives placed upon us.

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 either the DG incentive or other innovation incentives would have to be made significantly more powerful and/or flexible to incentivise the DNOs to make any significant investment in their networks 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.

#### **2.4.4 A Framework for Incentives**

Incentive schemes that promote performance in areas that meet customers' needs and are controllable by management, with logical methodologies and realistic targets and

rates, are the best way to drive and sustain real behaviour changes. The objective of incentives should be to drive efficiency improvements that assist future customers.

However, particularly in the area of environmental objectives, the quantification and measurement of these issues is not straightforward. Even where the “common currency” of carbon equivalence can be established (eg for fuel use, losses or SF<sub>6</sub>) difficulties can arise relating to both the extraction of robust measurement data and the establishment of consistent calculation processes. When seeking to design incentive mechanisms to encourage wider sustainability issues it is more complex still to identify objective measures. It is also clear that in many environmental areas the DNO can be said to influence rather than have full control over the outcome.

Given the above background, it may not always be possible for an incentive mechanism in this area to satisfy the five simple tests that would normally be applied, ie:

- 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 therefore perceive a range of incentive structures, dependent primarily on an assessment of 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 targeted on the controllable elements (eg similar to the current DG incentive), or
  - Innovative approaches on a project-by-project basis where a DNO might take more risk where the benefit to customers could generate a reward that was attractive enough
- DNO cannot act directly now but can build capability for the future:
  - Mechanisms similar to IFI to promote investment for the future
  - Increased flexibility of the regulatory framework

We comment more on the details of specific incentive schemes below, particularly Sections 2.5 (Distributed Generation) and 2.6 (Innovation and Future Networks).

## **2.5 Distributed Generation (2.22 – 2.47, Appendix 6 & Appendix 14)**

### **2.5.1 Summary (2.22 – 2.25 & Figure 2.3)**

- The major constraints on DG development in our area to date have not been network-related; however despite this background we have continued to

develop our own contributions to the facilitation of DG. For the future we are concerned that there are aspects of the current regulatory framework and the incentives on DNOs that if left unchanged would restrict our ability to innovate to facilitate DG. We have identified significant features of the regulatory framework that need to be addressed in order to provide clearer investment signals to DNOs and DG developers.

- We support standardised information on how to connect, where this is both justified by customer need and the additional costs are allowed in the price control.
- We support the implementation of cost reflective Use of System charges, including the extension to generators connected before 2005.
- We support continuation of the DG incentive with sufficient power to encourage DNOs to continue to reduce reinforcement costs and stimulate more MW to connect. We also see the proposed innovation incentive to be crucial in bringing forward innovative technical and commercial solutions to DG issues.

### **2.5.2 Regulatory Barriers**

The major reasons for the level of DG to date being lower than forecast have been constraints on developers that are outside the DNOs' control. We are concerned however that as a greater volume of DG comes forward there are aspects of the DNO regulatory framework, in particular the interplay between specific incentive schemes, which would actively discourage innovatory approaches and the facilitation of DG if left unchanged. We have identified significant features of the regulatory framework that need to be addressed in order to provide clearer investment signals in this area:

- Remove the unit based revenue driver
- Equalise opex and capex incentives (see Networks Chapter). In particular:
  - There is currently a strong disincentive to make any switch from capital to operational expenditure. This balance needs to be reset in order to encourage decision making that optimises lifetime costs on behalf of customers.
  - There is no clarity in how payments to generators or demand for network services would be treated as network costs.
  - In contrast to the likely costs, the potential revenue from any pro-active, enabling or semi-speculative investment is much more uncertain.
- Remove the distinction between demand and generation revenue "pots".
- Do not discriminate between pre and post 2005 Generators
- Allow Asset Adoption Payments to reflect more network cost in UoS, thus increasing marginal cost "pot" for appropriate sharing between generation and demand
- The potential increased returns from the DG incentive would only justify pro-active investment in advance of user commitment if DNOs considered their influence could match or outweigh the other barriers to connection (funding, planning, transmission access and installer/equipment supply chain). This is clearly not the case.
- An additional risk is that Ofgem has not clarified the application of caps and collars on DG income.

- Pro-active or semi-speculative efforts involving capital expenditure appear fairly likely to be judged as inefficient investment and thus a high cost to a DNO. In the run-up to DPCR4, we suggested a pro-active scheme to invest in advance to facilitate a step-change in connection capacity on our generation-congested Cumbria network. This was effectively refused by Ofgem based on the logic that generation should be incentivised to connect elsewhere in GB.
- There is a strong financial disincentive to compromise security of supplies for any innovative arrangement. Specific proposals made under the innovation incentive may need to address the balance of security risk between new and existing customers.

### **2.5.3 DG Information (2.26 – 2.32 and Appendix 6)**

We do not feel that the level of information and guidance provided by the current LTDS represents a particular barrier to DG connections and we believe that the quality of direct advice provided to generators meets or exceeds the expectations of our DG customers. However, we are keen to expand and improve the information provided by the LTDS where the effort in providing the information is justified by its potential value to DG customers. Our response to the specific proposals in the Policy Paper and Appendix 6 follows.

We agree that it would generally be inefficient to require DNOs to simply extend the current level of network data provided for EHV networks to the HV networks. However, we also agree that high level HV network information could be provided to help DG stakeholders at the early feasibility stages of project development.

We currently provide a full version of our LTDS, for free and online. High level information is available to anyone accessing our internet website and for security reasons the detailed information is accessed via a password protected area of our website. Passwords are available free of charge for any bona fide user.

We agree with the proposal to produce LTDS to a standard format across all DNOs. This will enable national DG developers to streamline their processes and reduce their costs. We welcome the proposal to link the format to the data requirements of the annual cost reporting exercise (RRP).

We agree with the proposal to incorporate a new section into the LTDS providing information on connection process and costs, and would anticipate implementation by April 2010.

We fully support the existing ENA initiative to review and rework the existing Connection Guide in 2009. Please note that this document is not the property of the ENA; it now belongs to the Distribution Code Review Panel, although its update will be funded by the DNOs through the ENA.

We agree with the aspiration to provide web-based indicative costing information but have a number of reservations. We are unsure whether the demand for such a service exists to justify the costs and complexities incurred. We also feel that there are many bespoke factors that influence the final cost of connection and it would not be practical to build this level of detail into the costing methodology; thus costs derived from the

service could be highly misleading in some cases. Nevertheless we will now look to develop such a service in line with the rest of the DNOs.

We currently provide GIS HV network maps on request for which we levy a charge. The principle of charging for this service is defined in the ESQCR that states that reasonable costs can be recovered. It is also technically possible to provide the maps via our website although there may be licensing issues surrounding the use of the Ordnance Survey background maps used with our HV network maps. We are able to develop 'capacity' maps indicating available capacity for DG connections but we would first want to see a common definition of network capacity in respect of DG used across all DNOs. Furthermore, the geographical area serviced by GSP and BSP can be reasonably estimated and are distinct; this is not true of the network below the primary substation level, particularly in urban areas, and hence the 'capacity' map approach would be best limited to EHV networks.

We are surprised by the suggestion that DNOs should complement their connection charging methodology statement with specific examples of DG connections, as this has been a feature of our connection charging statement for some time. We agree that there may be merit in agreeing common examples for all DNOs covering a range of generation options from urban microgeneration to large/medium power stations and for different fuel sources. The examples could detail the assets involved, a representative minimum cost connection scheme and indicative costs. This should however be caveated by our previous comment that each connection needs to be treated on its merits and examples can only ever give approximations to the actual costs likely to be involved.

We welcome the proposal that DNOs make leaflets/web-information available to indicate where DG can advantageously be connected, although again we believe this will only be really helpful to customers following a reasonable level of standardisation of approach between DNOs.

Paragraph 2.31 raises the specific issue of information provision to promote DSM. We believe that it is unlikely that a single customer alone can defer reinforcement by DSM techniques, and that successful implementation will require the bringing together of a range of customers having differing objectives. We have a pilot project underway involving a group of business customers and, should it result in a positive outcome, would be pleased to raise the profile of this initiative to aid better understanding. The project is at an early stage, in particular in terms of tailoring the business proposal for each individual customer. We therefore believe it would be premature to apply a blanket approach within the LTDS to the presentation of areas where customers could engage in DSM initiatives; however as we gain more experience of developing DSM, we will expect to refine the process by which we approach and make information available to potential DSM participants.

#### **2.5.4 DG Use of System (2.33 – 2.36)**

We do not believe that current connection and UoS charges form a significant barrier to the connection of generation; however we support the need for cost-reflective use of system charges and are taking a leading role in developing the industry working groups aimed at delivering a common charging methodology across all DNOs. We continue to have strong reservations regarding the value of a common licence condition

in this area and prefer to concentrate efforts on seeking pragmatic solutions through continuing engagement. However we would welcome an informed and impartial review of EHV charging methodologies, whether by Competition Commission or another body, if there is industry support for this means of bringing the issue to a conclusion.

Our current charging approaches correctly reflect the additional costs that DG causes when it connects to the system, however they do not yet adequately reflect the benefits that DG may bring to the network in deferring the need for future demand-driven network reinforcement. Where generators do provide benefits which defer the need for reinforcement then the cost should be borne by distribution customers and not by other generators. Separate price-controls for demand and generation customers prevent the DNO from providing fully cost-reflective charges, and in particular cause charges to DG to be higher than they otherwise would have been. This issue needs to be addressed as part of DPCR5.

It became clear during the discussions around DPCR4 that a separate revenue pot for GDUoS would severely weaken the incentives on generators to connect, since any rewards the DNO earned as a result of the DG incentive would need to be recovered from the (relatively small) group of generators facing GDUoS charges. This would also undermine the idea that consumers should contribute to the costs of encouraging DG connections since it would be they who would in the longer term benefit from the reductions in carbon emissions likely to result. From our discussions with Ofgem at that time we were led to expect that the two revenue pots would be merged in 2010 at the latest. We therefore do not believe that any linkage between this issue and the proposed Collective Licence Modification is either warranted or necessary.

We are pleased that Ofgem are looking at the impact of connection charges as well as use of system charges in providing the correct pricing messages to customers. However we believe that this is not simply a matter of moving to a shallow or super shallow connection boundary as such an arrangement when combined with use of system charges based on forward looking costs does not provide the correct economic signals. This is demonstrated by the following example, where a generator has two options for connecting to the system:

Option 1        Significant reinforcement option, creating additional spare capacity on the network. The initial connection costs are high but future use of system charges are low due to the spare capacity created.

Option 2        Minimal reinforcement option, but leaving minimal spare capacity on the network. The initial connection costs are low but future use of system charges are high due to the low level of spare capacity.

Under a shallow or super-shallow charging regime the generator would pick Option 1, as a significant proportion of the initial investment costs would be borne by others and the future use of system costs would be less; the lower overall cost solution for connection would be Option 2 however.

A further issue is that pure forward looking charges do not give efficient signals to customers wishing to connect to the system, as the charges will change completely as soon as the customer connects to the system if they trigger reinforcement. The statement in Appendix 6 that the introduction of UoS charges that provide locational

and cost reflective signals would mean the shallowish connection charge boundary may no longer be required is open to challenge, based on the current approaches being considered for use of system charging. Such an approach would mean that generators would locate in inefficient and uneconomic location as they would not have to bear the cost of their decisions.

Our overall conclusion is to support an effective adjustment to the connection boundary, as this brings more assets into the pricing model that provides the long term forward looking price signal for both demand and generation; however we contend that arrangements based on Asset Adoption Payments provide a more robust solution than simply defining a shallower physical boundary, since by making a payment on the basis of the average value of the network to be adopted, the strong locational cost message provided at the time of connection charges is retained.

It is important that effective connection charge signals are retained but we believe that the current connection boundary should be reviewed to ensure cost signals do not deter the economic connection of generation. We have advocated this for some time and are leading an industry review of connection charging principles. We believe that the issue of connection boundary and Asset Adoption payments should be reviewed with the objective of providing a more robust framework for equitable demand and generator charging, leading to a reduced need for demand reinforcement, to be reflected through ongoing use of systems charges.

#### **2.5.5 Pre 2005 Generation (2.37 – 2.41 & Appendix 14)**

We support the principle that all distributed generation should pay use of system charges. In principle, as the new charging arrangements are based on forward looking costs, sunk costs and sunk contributions made by generators would not need to be taken into account in setting these charges. This was the case when changes were made at DPCR4 for EHV demand customers, with the only transitional arrangements being the phasing in of charges, and there is a case for a similar treatment here. However, we have some sympathy with the view of generators that they have paid for access rights in their connection charges, and wish to find a pragmatic solution that will accelerate the transition to cost-reflective Use of System charges for all users.

In terms of pragmatism we are conscious of the potential administrative effort required to administer compensation arrangements with a large number of small generators, also the increasing difficulty in obtaining reliable data as we go back further in time. We therefore suggest it would be sensible to put in place both:

- a cut-off date – we suggest a date 15 years prior to the scheme coming into operation; this would be consistent with the DG incentive and the project financing life of many of the early post-vesting power station projects
- a de-minimis threshold, of say 5MW of installed capacity

It needs to be clear that the relevant customer contribution relates to the reinforcement costs of shared networks rather than the total cost of connection. It should also be clear that any compensation payments will be added to RAV.

### 2.5.6 DG Incentive (2.42 – 2.47)

The “Future Network Architectures” report (2007) by PB Power and Lower Watts Consulting for DBERR supported 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. It also provides an incentive on DNOs to reduce reinforcement costs.

The DG incentive is fit for purpose in terms of driving behaviours; it was not designed to drive volume. We welcome consistency and continuity in this area and agree that the structure of the DG incentive should be retained as the means to set a DNO’s allowed revenue from generation customers.

Similarly, for comparability and transparency, all types of DG should remain included in the incentive, including any offshore generation projects (embedded transmission or just connecting to distribution). We welcome the confirmation that embedded transmission will be treated as Relevant DG since we believe that this was always the clear intent, supported by the definitions in the DG RIGs.

We note Ofgem’s proposal to reduce the incentive rate, and question whether this is appropriate at a time when there is a clear imperative to stimulate more of the behaviours envisaged by the DG incentive. It is important to retain or increase the incentive on DG as the DPCR4 period has been characterised by DG schemes generally picking the easy, cheap connections. Policy developments such as feed-in tariffs will make otherwise non-viable, more expensive, schemes economically attractive to developers.

It is also the case that we have not yet seen much penetration of the technologies such as small CHP and biogas that are intrinsically more expensive to connect per MW. There is therefore greater risk around the costs forecast for these technologies, which should be taken into account in setting the incentive parameters. We have some detailed comments on the mechanism by which the incentive rate should be reviewed:

- Care needs to be taken in comparing the FBPQ with the DPCR4 DGBPQ, particularly as Table LR2 is based on direct costs only, whereas DPCR4 forecasts were quoted as total costs.
- The DPCR4 forecast was based on the predicted reinforcement cost per kW for the portfolio of generation predicted to connect during DPCR4, as opposed to the subset of generation which actually connects as Relevant DG rather than under pre-2005 rules.
- A further point relates to the change in connection boundary. Costs in the DGBPQ were categorised on the basis of a shallow connection boundary, and the incentive scheme parameters set accordingly. Following the late change to a shallower boundary the “fix” was added in order that the incentive would effectively continue to operate on costs calculated on a shallow basis (by making adjustments to account for the customer contributions made against the shallower boundary). Thus, in order to compare like with like, it would be appropriate to compare the total use of system costs (ie Use of System Capex for DG plus Shared Connection Capex for DG) in the current forecasts with the costs identified at DPCR4. This is in addition to including the indirect costs, as mentioned above.

- Alternatively, the scheme could be reset to operate solely on the Use of System Capex element of the reinforcement costs.

## **2.6 Innovation and Future Networks (2.48 – 2.75 & Appendix 15)**

We have responded in Section 2.4 (Future Uncertainties) to the general question as to whether the DNOs need to change their way of working.

We support Ofgem's view that the existing RPZ scheme does not work and does not encourage the combination of innovation and actual generation to come together as a whole scheme. There are many reasons behind this but certainly the rigid requirements of the scheme have worked against bringing a scheme to fruition.

We are fully committed to R&D investment under the IFI and are the only DNO that has utilised its full allowance. We are fully supportive of the IFI mechanism being maintained throughout DPCR5 as it is our belief that the reinvigoration of R&D that has occurred under IFI will greatly assist Ofgem's aims in developing the network under the proposed innovation mechanism. There are projects that we are currently running under the IFI programme which are effectively one-off trials as part of development of equipment which have the potential to lead to wider-spread application in the future. In particular we would highlight our projects on Distribution Transformer Online Tapchangers, Superconducting Fault Current Limiters and Overhead Line Monitoring.

We are also engaged in developing innovative practice outside the IFI arrangements, where other incentives provide a sufficient driver. Examples of this are our Automatic Restoration System and Transmission Restoration System projects, involving the application of software algorithms to our telecontrol system to assist with automatic restoration of supplies to improve QoS performance. We can point also to developments not supported by any specific incentive, such as our assessment of our carbon footprint, including embodied carbon, which we would expect to influence practices in the future.

It is our belief that the wider implementation of projects initiated under IFI will only begin to work through the encouragement of an incentive. Whilst there are potentially many sources of funding in the marketplace these usually take time to become familiar with and require considerable administrative work to actually access for specific projects. Our experience with IFI has seen similar experiences with a variety of R&D funds available but it takes time to become aware of these, build up relationships and understanding such that they can be accessed when a suitable project is available.

To provide such an incentive, a new approach is needed which provides the appropriate risk-reward balance for those intermediate commercial arrangements for technical or commercial projects between business-as-usual connections, pure R&D under IFI and the narrow definition of an RPZ. The new innovation incentive could provide this, and we welcome a more broadly defined mechanism to encourage technical and commercial innovation in real network examples.

Of the options discussed for taking forward an innovation mechanism it is felt that a amalgamation of option 1 and 2 is the most flexible approach and likely to lead to

the greatest benefit to the network. Some policy areas are developing very quickly, and we are unable to place project proposals in the FBPQ for ex-ante funding (option 1). We suggest that the best approach is to make proposals to Ofgem after the FBPQ **and** during DPCR5 (not just during DPCR5 as suggested in option 2). This would allow rewards based on project outcome, providing incentives for DNOs to deliver and for risk to customers to be reduced. It is felt that the above combination of options provides the most flexible approach, and individual negotiation of proposals will ensure that the level of risk the DNO is taking is balanced by reward – so customers either take some risk or fund more reward.

Our view is that these proposals will allow both larger scale projects perhaps covering larger areas of the network where the ability of the existing network to accept additional generation is very limited and also smaller scale projects where standard network equipment or designs can be replaced by different approaches that will provide more flexibility/capability for the network in the future. Once we understand the terms of any new innovation incentive, we would hope to make proposals as soon as possible, hopefully within the next 12 months and at the latest during DPCR5, in areas such as:

- Pro-active liaison with developers to plan future capacity needs
- Investment to enable multiple DG schemes in a geographic area
- Investments to allow a step-change in capacity on the generation-congested Cumbria network
- Investment for electric vehicle charging in urban areas
- Policy changes for new asset specifications to manage higher urban fault-levels and reverse power flows.

We reject the post-period discretionary reward/penalty (Option 3) as we can not build a business case on discretionary reward, and we view discretionary penalty as an arbitrary increase in risk. As we say in the introduction to this section, it is not sensible or appropriate for DNOs to take all the risk of early investment and then have their efforts judged with the benefit of 20:20 hindsight.

## **2.7 Transmission Exit Charges (2.76 – 2.82)**

We are concerned that the introduction of an incentive on transmission grid exit charges would introduce risks which are not within our control, since the charges are demonstrably volatile and a large proportion relate to the refurbishment of existing capacity rather than the installation of new capacity to satisfy DNO requirements. Although we generally welcome incentives that meet the key criteria of measurability and controllability we believe that in this instance the most efficient form of funding is via cost pass-through rather than through the introduction of a potentially flawed incentive scheme. Our main issues are:

- Charges are clearly difficult to forecast, even for NGET.
- Prices are already regulated under TPCR and should not be regulated again.

- New or incremental MW volume only drives (indirectly) a very small proportion of overall charges and total charges are dominated by the recovery of costs associated with the refurbishment of existing assets.
- Despite the absence of a direct incentive, we already influence charges to the extent possible on behalf of our DUoS customers.

DNOs themselves have very limited influence on exit charges. However, NGET on the 5th Nov sent out an open letter to the industry to seek feedback on new pricing proposals for transmission connection offers. Ofgem make reference to innovative deals to fix contract prices, and we see this as a more effective approach to the issue of controlling and minimising the effective costs of providing Grid capacity.

### **2.7.1 Volatility of Exit Charges**

Exit charges are volatile and not easy to forecast. In the two years to 2007/08, exit charges have risen from £5.8m to £9.1m, an increase of 57%. This increase has been largely driven by the asset refurbishment activity at three of our Grid Supply Points (GSPs). Exit charges are forecast to increase further during DPCR5, again because of asset replacement, not reinforcement.

Predicting future exit charges is not straightforward due to the complex nature of the drivers. NGET themselves only provide DNOs with a “year ahead” forecast of existing charges, and they do not include any charges for new or replacement assets in this forecast. A complete picture can only be obtained by assessing “Variation to Bilateral Contracts”, assuming that indicative costs and construction timescales outturn as predicted.

### **2.7.2 Price Effects**

We do not believe that an incentive based on total cost is appropriate or necessary since these costs have already been subject to a Transmission price control. If they are then subsequently brought into the Distribution Price Control they would be regulated more than once, which contradicts the principles established in 1990.

Even new connections which are negotiated between the DNO and NGET are at no more than cost plus a reasonable rate of return (as per NGET’s licence). Combined with NGET’s duty to develop and maintain an efficient, coordinated and economical system, any costs passed on to the DNO should be at an efficient level.

This suggests that a better incentive option might be based on a volume driver, as in Ofgem’s option 2. However Exit Charges, unlike TNUoS, are not based on the marginal costs of capacity; they essentially represent the annuitised recovery of costs associated with connection, which include both reinforcement and refurbishment. We expand on this below.

### **2.7.3 Volume Effects**

We do not believe that the requirement for new DNO exit capacity is a significant driver of exit charges.

Major asset refurbishment has taken place at three GSPs in our area over the last five years. The costs of this work will continue to be recovered during DPCR5. During DPCR5 four GSPs are scheduled for capital works, with only one being linked to reinforcement needs.

#### **2.7.4 DNO Influence over Exit Charges**

Ofgem's statement in paragraph 2.77 that DNOs are isolated from exit charge risk is not strictly true. Exit charges may be outside the price control, however they do form part of actual demand revenue, and therefore influence the levels of under/over recoveries that occur. If the DNO is not to suffer cash flow impacts or penalty interest payments on correction, then it is in the DNO's interest to forecast exit charges as accurately as possible.

Furthermore, although there may be limited incentive to influence costs, we continue to devote resources to ensure costs incurred are as efficiently delivered as possible. We can point to several examples of how we proactively maintain the commercial aspects of exit charges on behalf of our DUoS customers:

- The Padiham reinforcement of the late 1990s where we, under derogation, built a new 132kV line between Blackburn and Padiham to provide the minimum overall cost option by avoiding the addition of another SGT at Padiham; this despite the fact that Padiham is classified as a Transmission Infrastructure System Asset (TISA), ie a shared rather than sole use connection, and therefore does not attract exit charges.
- Management of Bilateral and Variation to Bilateral agreements,
- Monitoring for CUSC compliance eg ensuring NGET provide reconciliation invoices within 12 months of completion,
- Challenge the reconciliation process where appropriate, particularly when interest payable is involved,
- Built a relationship with NGET's commercial section. We meet on a half yearly basis to discuss governance and process issues, ongoing and future projects. We believe we are the only DNO to have this relationship with NGET.
- We recently shared our "exit charges forecasting model" with NGET to get their comments on its ability to derive exit charges. They commended it on its ability to accurately model the CUSC methodology.

## **2.8 Losses (2.83 – 2.103 and Appendix 6)**

### **2.8.1 The Current Losses Incentive (2.85 – 2.86)**

We recognise the significance of losses in terms of DNOs' own carbon footprint; however we believe that the current mechanism for incentivising loss reductions does not give sufficiently clear investment signals, and propose a more focused incentive in its place.

We have previously (as far back as 2002) expressed reservations to Ofgem over reliance on a simple incentive applied to aggregate losses. Our concerns continue to

relate to the significant data measurement issues and the limited control that the DNO can exercise over the losses measure as currently defined. We have supported the ENA proposal to introduce an alternative input-based mechanism in order to target the areas of DNO investment that can have incremental effect on overall losses performance.

Our concerns regarding controllability can be characterised by the fact that, as highlighted by Ofgem in their Sustainable Development Report, losses from electricity transmission and distribution networks increased in 2007/08, a reversal of the downward trend seen in earlier years, whilst demand had not increased over the year.

Firstly, we note that there is a wide spread in incremental performance between DNOs both in terms of distributed units (range +1.8%/-2.6%; average -0.2%) and lost units (range +1.9%/-1.0%; average +0.3%). This range of data is entirely consistent with the known volatility of results due in particular to:

- Metering accuracy
  - Half hourly meters for the SVA market are specified with an accuracy of  $\pm 1.0\%$  or  $\pm 1.5\%$  depending on the size of the load. Existing NHH metering has to be within the statutory limits, defined as +2.5%, -3.5%. Although this does not mean an error of this level, it is worth noting that for ENW a range of  $\pm 1.0\%$  has an approximate 20% effect on the losses figure.
- Settlement uncertainty
  - The BSC Audit opinion for 07/08 identifies a number of specific errors in Settlement, quantified in both gross terms and as volumes “unlikely to be corrected”; the aggregate quantities being 1352GWh and 483GWh respectively. The latter number pro-rates down to approximately 3% of losses for ENW.

From 2006/07 to 2007/08 ENW experienced a fall in reported distributed units of 0.8% and a slight increase in reported losses in line with the national average of 0.3%. We have identified three main issues that might help explain this effect:

- The relative “peakiness” of the load shape (for a given unit demand) will drive variable losses higher due to the square law relationship. ENW actual Simultaneous Maximum Demand (not weather corrected) increased by nearly 3% over the period in question.
- Non technical losses are increasing. There is evidence that theft is rising above historic levels, possibly driven by high electricity retail prices and other issues relating to personal finance.
- Increasing amounts of DG will affect network losses unpredictably. Large volumes of loss-saving microgeneration are yet to materialise on the network; whereas we are currently seeing the connection of a few large schemes situated in remote locations that will inevitably add to losses.

We view these issues as sufficiently major to call into question the validity of the current DNO losses incentive mechanism as a means of measuring the effect of DNOs’ actions with regard to losses. Furthermore, the measurement issues surrounding the current incentive structure make the identification of the effects of individual investments difficult to identify. Although it is true that measurement volatility has no

direct effect on the loss saving itself, it is difficult to make a business case for investment when it is not possible to demonstrate the results of the planned action.

### **2.8.2 Current incentive (2.87 and Appendix 6, 1.54 – 1.56)**

We have reviewed the simple spreadsheet used by Ofgem to investigate the level of incentive to invest in a higher cost, lower loss transformer. Although we agree with the order of magnitude of the loss savings identified and the consequent positive NPV in some circumstances, at the current incentive rate these scenarios occur when the minimum level of capex roller is applied. This effect should be taken in the context of the possibility of capex incentives increasing to become more aligned with opex incentives in the future.

Secondly, there is a level of risk around the actual loss savings achieved by these investments, particularly in respect of variable losses. When coupled with the measurement issues mentioned above these issues are an additional disincentive to invest, which could be addressed by moving from the existing incentive structure towards more targeted input incentives, in conjunction with consideration of the incentive rate itself.

### **2.8.3 Detailed Mechanism (2.88 and Appendix 6, 1.57 – 1.60)**

We support the adoption of a consistent industry-wide approach to the reporting of losses. To the extent that the alignment of the detailed mechanism across DNOs means a change to current practices for an individual DNO, then a commensurate change would also have to be reflected into the associated targets for the affected DNO(s).

### **2.8.4 Commercial Losses (2.89)**

See comments under “Theft” below.

### **2.8.5 DNO Proposal (2.90 – 2.92)**

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

There may be a role for a continuation of the current mechanism with a reduced incentive rate (and possibly also capped exposure) as an overall measurement designed to incentivise data quality. A reduced rate is justified for two main reasons:

- improvements in data quality serve more accurately to reflect costs, rather than directly reducing energy generated. Including a carbon price would therefore be hard to justify; and
- given the clear volatility in settlement data and hence on reported losses, customers could reasonably apply a deep discount to the price they were prepared to pay for losses reduction, on the basis that they could not be sure that reported losses truly reflected underlying losses.

### **2.8.6 Ofgem Proposal (2.93 – 2.97)**

We strongly favour an input-based scheme as opposed to the retention of the current mechanism. We disagree with the statements that “the output-based scheme measures actual losses and reductions achieved” (due to volatility issues) and “maintains the focus on environmental benefit” (due to the inclusion of non-technical effects).

If the existing mechanism is to be retained however:

- The target should be set on 10 years history (rather than 5 years or less) to help overcome settlement related volatility. Volatility effects could be further mitigated by the use of five-year rolling totals in place of in-year “actuals” when setting targets.
- The target should be adjusted to take account of FBPQ initiatives.
- The target should be adjusted to take account of detailed methodological changes.
- An increased incentive rate would need to be associated with the introduction of caps and collars on overall return; level of caps to be set by RORE considerations.

### **2.8.7 Incentive Rate (2.98)**

We support the enhancement of the incentive rate to explicitly factor in the Shadow Price of Carbon. We believe that it is right to fully factor in the costs of externalities in order to provide the correct economic signals for investment. We are conscious however that this would magnify the range of possible financial outcomes compared with other incentives such as QoS; coupled with the concerns regarding inherent volatility in output-based measures of losses, we believe that, particularly if the existing mechanism is used, an increased rate should be associated with the introduction of caps and collars. The appropriate levels for such caps and collars could be determined by consideration of relative levels of RORE between the various incentive mechanisms.

### **2.8.8 Smart Metering (2.99 – 2.101)**

We set out our opinions on the proposal to install secondary transformer meters in our letter of 18 November 2008. In summary, we believe there are no practical obstacles to the installation of the smart meters, although the two year timescale is possibly over-ambitious and the provision of an associated data network requires more investigation. If a clear and rapid decision were made on the infrastructure that will be utilised for the national roll-out of smart metering to all customers, then meters compatible with this infrastructure could be fitted and data made available as soon as the infrastructure for the national roll-out was in place.

The installation of this metering would certainly assist in making a purely output-based losses incentive a more practical proposition, but would not alleviate all the concerns associated with the existing mechanism. The cost of the programme is clearly high in relation to the specific benefits attributable to losses and, therefore, any cost and benefit analysis would need to include the wider benefits associated with the increased network monitoring and the real time provision of information to enable more active network management.

### **2.8.9 Theft (2.102 – 2.103)**

We believe that Ofgem are correct in identifying that the volume of theft has been increasing over recent years; in 2007/08 approximately 2% of ENW reported losses were due to identified theft, itself being an unknown fraction of total theft. We are very keen to see the incentives on Suppliers to address theft issues enhanced, and believe that a review of arrangements in this area is long overdue. We believe that DNOs have an important role to play and have a number of ideas that we are keen to contribute to the debate.

### **2.9 SF<sub>6</sub> (2.104 – 2.106)**

We have previously advocated the introduction of an incentive for SF<sub>6</sub> leakage if this were structured to mirror the TPCR mechanism; however we have always recognised that, as for any incentive scheme, this should be subject to measurement and consistency issues being overcome.

Bearing in mind that the above issues will take time to resolve, we welcome the phased development of standardised measurement techniques, and also the important step of incorporating SF<sub>6</sub> within a holistic approach to business carbon accounting, based on the “common currency” of tCO<sub>2</sub>e. This will allow the relative effects of various activities to be readily seen, allowing management choices to be made between the various mitigation actions, impinging on diverse areas such as electrical losses, use of fuel or SF<sub>6</sub> emissions.

### **2.10 DNO Business Carbon Footprint (2.107 – 2.112 & Appendix 6)**

We welcome Ofgem’s approach to carbon footprint measurement – the individual elements of the report substantially reflect those included in our own 2007/08 carbon footprint report, previously copied to Ofgem.

The intention seems to be to achieve a reasonable balance between materiality of emissions and administrative effort required; however this balance must be kept under review as the detail is worked up. In particular, it would probably not be sensible to take the approach of capturing emissions from activities outsourced to independent contractors to the full length of the supply chain, bearing in mind the potential extent of the contractual negotiations required. It would be preferable to capture a high percentage of the footprint through a robust, replicable reporting process than blur the overall results through the inclusion of less reliable data from minor sub-contractors.

The phased introduction of data submissions is sensible, giving the industry a reasonable time to develop and standardise measurement methodologies, to the appropriate extent. We intend to submit data for 2008/09, for information only, to assist in the development of the reporting framework.

We would expect the developed measures to lead on eventually to some form of incentive scheme, with the DNO league table providing a first step in this regard. We would however expect that an absolute measure of carbon footprint would reflect variations in economic activity as well as the relative success in controlling per-unit emissions; we would expect this issue to be addressed within any published figures.

We note that this methodology does not include consideration of carbon embedded within assets. We agree that this is sensible at this stage on grounds of proportionality, data gathering and data reliability. However, this is a developing area with the potential to influence decision-making in the future. We have already shared our work to date on this with Ofgem, and will continue to keep Ofgem updated as our thoughts develop.

## **2.11 Undergrounding in AONB (2.113 – 2.115 & Appendix 6)**

### **2.11.1 Allowances**

We have 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 and are pleased that Ofgem has committed to continuing the scheme.

We are also pleased to see that Ofgem has acknowledged both customer willingness-to-pay for further work in this area, and the shortcomings of the current scheme arrangements as flagged by ourselves and other DNOs. We agree substantially with the proposals set out in Appendix 6, in particular the clarification regarding potential use of the scheme as 'top-up' funding on other work.

It is however not clear how Ofgem have derived the proposed allowances per DNO in Table 1, Appendix 6 and we are confused by the variability of allowance per DNO compared to their DPCR4 equivalents. Aside from the potential designation of new areas, the only significant influencing factor on this would appear to be the introduction of regionally-specific willingness-to-pay. It would be helpful if Ofgem

could clarify the basis on which the proposed allowances were developed, and also the basis of the amounts involved (direct costs only?)

Environmental performance of the electricity distribution sector is not simply a matter of the extent to which consumers are willing to pay but derives from a series of duties placed upon Ofgem and the DNOs, which, in turn, are based on the public's priorities as 'citizens' (acting collectively, in the public interest) rather than the aggregate preferences of consumers (acting individually for their personal interests). We also note Ofgem's encouragement of stakeholder engagement in regional plans and observe continuing stakeholder enthusiasm for a programme of undergrounding that seems to be broadly aligned with customer's willingness-to-pay. As such, we believe that the overall quantum proposed for ENW does not appear inappropriate, and is broadly in line with our current plans.

With respect to the point regarding customer willingness-to-pay for the scheme being predicated on certain volumes, the clarification regarding the potential use of the scheme to provide 'top-up' funding to existing projects may allow significant lengths of line to be undergrounded relatively cheaply (as the scheme is only funding the increment), which could offset the inclusion of more expensive lines in the programme to deliver broadly equivalent or increased volumes. We also note that customers were asked about undergrounding 5% of eligible lines; whereas the proposed allowances are more in line with their DPCR4 equivalents, ie around 1% of network on a national basis (albeit highly variable between DNOs as noted earlier), so observe that the direct linkage between willingness-to-pay and the scheme as proposed is already broken. We therefore suggest that removal of the cost caps is an appropriate response to stakeholder priorities, but one that will not necessarily result in a reduction of volumes below the overall expectations of customers. We discuss this further below.

### **2.11.2 Cost Caps**

The specific question raised by Ofgem in this section relates to the application of the cost caps which have, as per previous correspondence, prevented a significant minority of preferred schemes from progressing. We note that one option presented by Ofgem is to increase the current caps, but the levels suggested do little more than raise the 2002/03 price caps in the DPCR4 settlement to 2007/08 price levels. They therefore do not address the issue previously raised of scheme disqualification on the basis of unit cost, nor the unequal difficulty by voltage of hitting the applicable cap that we have experienced with the current scheme.

Our preference continues to be to remove the cost caps entirely, such that the regional stakeholder partners can prioritise on the basis of the impact on scenic quality rather than affordability within artificial constraints. Our regional partners have quickly developed an understanding of the operation of the scheme and are keenly aware of the potential trade-off between quantity and quality in this area. We also administer the scheme on a strict pro-rata basis such that the partners have autonomy over the approach they wish to take in consultation with their own stakeholders. This ensures that the decisions of one area do not have an impact on the others. Funding provisions are only re-allocated between areas with the unanimous approval of the regional Steering Group.

We therefore suggest that the cost caps are removed entirely such that high scenic quality but expensive schemes are permissible.

### **2.12 Fluid Filled Cables (2.116 – 2.120)**

We subscribe to the Operating Code and would support a common format for reporting oil leaks to both Ofgem and the Environment Agency.

We have developed and used a risk-based approach to targeting the replacement of fluid filled cables in DPCR4 and would support further development of an industry best-practice approach to assessing risk in this area. We would be keen to be involved in the further development of standardised methodologies, including how risk is recorded and managed. We have made a specific modest provision for FFC replacement for environmental drivers in our DPCR5 submission to address a small number of specific situations where the actual or potential loss of oil presents an unacceptable environmental risk.

We would support investment in the development of new technologies to detect leaks, for example the impregnation of oil filled cables with trace gases either reactively, following alarms indicating loss of oil or proactively, prior to leaks occurring, on high risk circuits. We are investigating potential projects that would be looking for IFI funding during DPCR5.

## **3 Customers**

### **3.1 Chapter Summary**

We are in broad agreement with Ofgem in their focus on customer satisfaction, and their wish to ensure that companies who provide the best overall service to customers, measured by a number of metrics, are the best rewarded.

#### **3.1.1 Broad customer satisfaction measure**

We support Ofgem's objective to incentivise DNOs to behave like companies facing competitive pressures and agree that the current telephony scheme provides too narrow an incentive. We agree with the proposal of developing a new broad customer satisfaction measure and running this in parallel with the telephony scheme for the early part of DPCR5 with a view to replacing it within the price control period. Ofgem are considering an advocacy measure of customer satisfaction which is based on whether customers would recommend the company to others. This may be difficult for a monopoly business. It is proposed that an independent market research agency would provide greater uniformity of approach and a greater trust factor.

#### **3.1.2 Telephony incentive scheme**

We support the proposal to streamline the existing survey questions and to take account of unsuccessful calls and messaging and also to standardise the assessment with DNOs contracting with a single provider.

#### **3.1.3 Competition in Connections (CiC)**

We support Ofgem's overall approach with regard to connections, in particular the recognition that the market is regional and a one size fits all approach is no longer appropriate. In terms of market segmentation we would advocate categorisation by voltage of the POC rather than the voltage of supply to customers as this is easy to monitor and better reflects the connections market.

We understand the difficulties in settling an appropriate margin level and are happy to use our recent commercial experience and benchmarking to assist Ofgem in setting a regulated margin at the right level. For simplicity this should be applied to both contestable and non-contestable elements.

We believe that there needs to be a comprehensive set of competition tests. We have had similar work undertaken by economic consultants IPA, which has identified that a competitive market exists in the North West. We should, therefore, be able to earn an unregulated margin for the final two years of DPCR4.

### **3.1.4 Connections provided by the DNO on a non-competitive basis**

It is only appropriate to bring in further customer protection into areas that Ofgem consider are not open to competition. We are supportive of some form of price regulation for smaller connections, preferably with Ofgem approving our prices following benchmarking with other companies. There should be no extension to regulation in competitive activities, even where the customer chooses the DNO.

### **3.1.5 Guaranteed standards of performance**

We support Ofgem's overall proposal that the performance standards remain unchanged and that the penalties are increased in line with inflation. We note Ofgem's comments on complaint handling and the possibility of a new standard in the future. However, given the recent introduction of a whole new consumer representation structure, we believe that Ofgem should wait a reasonable period of time before considering any new standards.

We agree that the current GS are adequate and support the decision not to make any structural amendments. The level of GS payments remains broadly consistent with annual DUOS charges and as such is effectively an annual money back guarantee for those customers subject to poor service.

We are particularly pleased to note that there is no intention to extend the GS scheme to include compensation payments linked to customers' potential consequential losses. It remains our view that customers are best placed to manage these risks. We comment further on non-guaranteed standards approaches to addressing business customers' concerns in the IIS section of our response.

### **3.1.6 Customer Service Reward Scheme**

We support Ofgem's overall proposal with regard to the customer service reward scheme, and agree that the value of the scheme should remain at £1m. We believe however that there could be more sharing of best practice so that ideas can be adopted by other DNOs.

### **3.1.7 Quality of service interruptions incentive scheme (IIS)**

We are acutely aware of the issue of regulatory uncertainty associated with the benefits of investments beyond the current price control. The current five-year arrangements for agreeing and setting targets and associated incentive rates can result in investment timing issues as the IIS rewards are effectively bounded within a price control period. One way to avoid this would be to replace the step-change of the ratchet with a glide-path, such that the five-year targets are set at a gradually reducing level from the current target level down to the current average level by the end of the subsequent price control period.

We agree in principle with the proposal to move to a scheme whereby all DNOs share equal incentive rates for customer interruptions and for interruption duration, since this approach is consistent with setting rates on the basis of the assessed cost to customers of supply loss. However it is also important to recognise that the existing arrangements have delivered significant performance improvements since their

inception and some consistency of investment signals needs to be preserved. This suggests that a transition to more cost reflective arrangements over a period of time may be appropriate.

Building upon previous discussions we are keen to finalise a treatment of liabilities associated with forced outages during periods of construction and maintenance activity at 132kV and 33kV; in particular to cap GS and IIS liabilities to ensure that customers do not see the costs of the associated risks crystallised into significantly higher capital unit costs.

We welcome the proposal to modify the calculation of CML targets for frontier CI performing companies. We are pleased to see that Ofgem have recognised the double ratchet effect which caused particularly onerous CML targets for DNOs at the frontier with respect to CI performance.

### **3.1.8 Worst served customers**

We support Ofgem's proposal, in principle, as it will enable us to focus on the small group of customers who are facing lower levels of service. An allowance is more appropriate than an incentive given the uncertainty surrounding definitions and in particular costs.

We have some concerns about the cost cap in that it may prevent us from tackling the very worst served customers, since relatively few customers benefit from individual schemes. The scheme should also allow non-network approaches such as installing generation, if this is the most cost effective solution.

## **3.2 Answers to Ofgem's Specific Questions**

**Question 1: Do you think that the range of existing and proposed arrangements will deliver the levels of service customers expect?**

See sections 3.3 and 3.4 of our response.

**Question 2: What percentage of revenue/return on equity should be exposed to customer service and how should it be split between the various areas?**

See sections 3.3, 3.4, 3.10.1 and 3.10.4 of our response.

**Question 3: Do you agree with our intention to develop a broad measure of customer satisfaction and the proposed advocacy approach?**

See section 3.5 of our response.

**Question 4: Do you agree with our proposed approach to connections, which of the options do you support and why?**

See section 3.7 of our response.

**Question 5: Do you agree with the proposed amendments to the IIS (in full) and what are your views on how incentive rates should be structured?**

See section 3.10 of our response.

**Question 6: Do you agree with our proposed long-term objective of DNOs being able to automatically know which of their customers are off supply and the exact times, and if so what is the appropriate timescale to achieve this?**

See section 3.10.2 of our response.

**Question 7: Do you agree with the proposed focus on worst served customers and which of the options do you prefer?**

See section 3.11 of our response.

**Question 8: We have raised some detailed questions throughout this chapter and the appendix. We welcome views on these issues.**

We address Ofgem's detailed questions at the appropriate points in our response.

### **3.3 Introduction (3.1 – 3.4)**

Customer service measures relate to the infrequent occasions when customers need to interact with us. For the overwhelming majority of our customers they have no need for any direct engagement with us. Where customers do need to interact with us, repeated customer surveys have revealed that they are generally satisfied with service levels and our service level performance record demonstrates that we continue to strive to maintain a good customer service performance. We are not complacent about customer service and we are supportive of efforts to continually improve performance across the broadest range of activities; however we do believe that it is important to recognise what we have achieved and that the potential for further improvement is limited and likely to be achieved by focussing in one or two specific areas. We are in broad agreement with Ofgem in the focus on customer satisfaction and we have supported Ofgem over the years in attempting to reach service levels that are both consistently good and affordable for customers and for DNOs.

We agree that the highest returns should be available to DNOs who provide the best overall service to customers measured by a number of metrics and delivered over time in a sustainable manner. Customer satisfaction should be measured in the broadest sense and should not be construed too narrowly.

Whilst an increase in the scale of incentive mechanisms would ensure DNOs become even more focussed upon the services customers value, we believe that such changes should be supported by robust willingness-to-pay evidence. Given the high levels of satisfaction that we observe already, such a check will ensure we are not striving for a service level that is greater than customers' requirements. The current willingness-to-pay survey highlights that the key measures should be network performance and the minimisation of interruptions and it should be recognised that there is generally a low willingness to pay for service improvements, but a strong desire to stop standards slipping back, showing that customers are generally content with our current level of performance.

### **3.4 Customer Priorities (3.5 - 3.12)**

We support Ofgem's objective to incentivise DNOs to behave like companies facing competitive pressures and that the current telephony scheme provides too narrow an incentive for DNOs to improve customer service overall. We therefore support the development of a broad measure of customer satisfaction. We agree, in principle, with your proposal running the new broad customer satisfaction measure with the telephony scheme for the early part of DPCR5 with a view to replacing the telephony incentive with this broader measure as soon as is practicable within the price control period.

Whilst we note the National Federation of Builders 2008 Utilities Survey cited poor communication as the main source of dissatisfaction for developers, this did not have any geographical information for us to gauge our particular performance.

We note the comments regarding worst served customers and we recognise that our communication with them could be improved. To this end we are developing new IT tools for our customer web pages showing current and planned activity.

### **3.5 Broad measure of customer satisfaction (3.13 - 3.16)**

As we have stated above, we support, in principle, a broader approach to measuring customer satisfaction as the current telephony measure is too narrow. This is, however, dependent on whether an appropriate measure can be formulated. The advocacy measure is certainly worth consideration though it may be difficult to apply this to a monopoly business. In addition or as part of the same problem, some of the identified attributes/interactions would have very small numbers to make an assessment on such as supply upgrades and plant enquiries. An advocacy metric maybe appropriate but perhaps would have to be based on a smaller number of areas where there is a more substantial customer interaction such as planned and unplanned power cuts, new connections and complaints. The use of an independent market research agency would provide greater uniformity of approach and a greater trust factor than if the surveys were done individually by DNOs. We would expect to see the measure developed and assessed over two years at least before targets are set and the measure is implemented in the licence.

### **3.6 Quality of telephone response (3.17 – 3.18)**

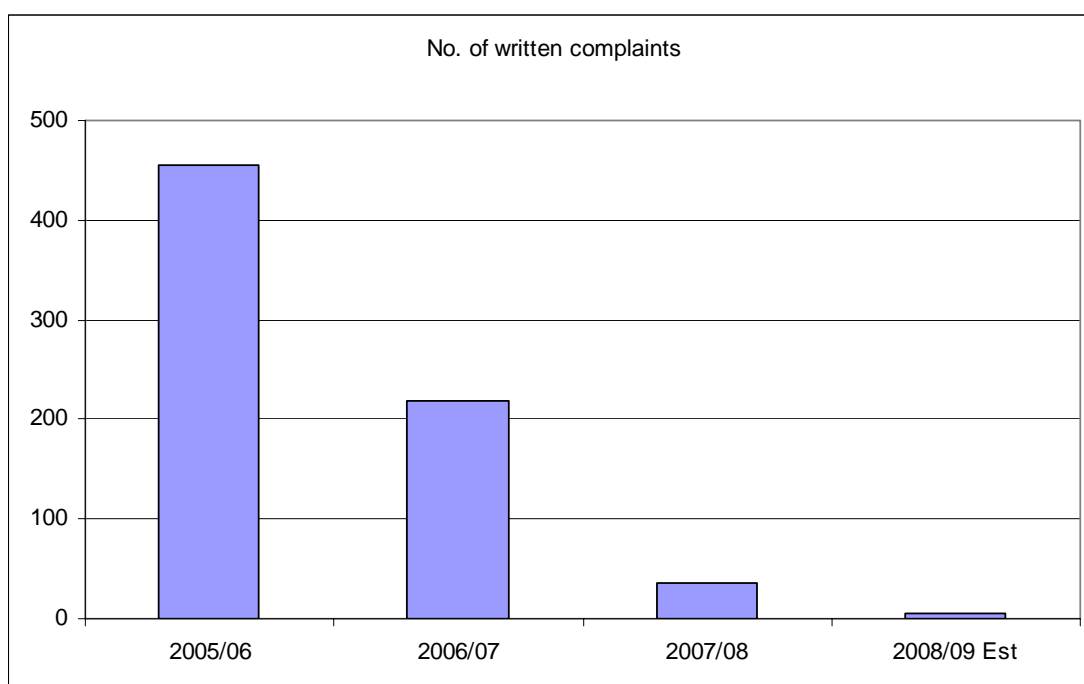
We note the Ofgem proposals which we support as a sensible way of streamlining the survey.

### **3.7 Connections (3.19 – 3.20)**

We support Ofgem's overall approach with regard to connections, which begins to recognise that effective competition is a reality in some areas and, for these regional markets, a one size fits approach is no longer appropriate.

Customer service is very important in the connections market and for many customers requesting a new connection or supply increase is a one-off experience, and hence poor service may not directly affect future market share. Customers who more

frequently require these services are house builders, and it is noted that the smaller builders, represented by the National Federation of Builders, report poor levels of service in particular relating to communication with utilities, with electricity companies being identified as the worst performers. The survey also highlighted nationally a lack of awareness by these customers of the competitive options available to them. In contrast, larger builders tend to use independent contractors for the provision of these connections, in the ENW area at least. Whilst we note the comments that customer service is poor, it is not clear whether this applies in all DNO areas. Our own data, shown below, demonstrates the improvements we have made in this area, which also corresponds to the increased competitive pressures we have faced over this period; this has required greater focus in this area of the business. The number of complaints should be considered in the context of the large numbers of customer interactions in the connections market. We would reiterate therefore that competition is protecting customers and remains an important driver of our improvement.



### 3.7.1 Competition in Connections (CiC) (3.21 – 3.27)

We strongly support Ofgem’s proposal to take a regional approach to the connections market as competition has clearly developed in some areas such as our own, but has not developed in others. We have advocated a regional approach for some time to reflect the clear differences in competitive activity. The paper identifies possible reasons why competition has not developed in other DNO areas. We have the following comments with regard to this, and potential barriers to competition:

- **DNO margins** – The key issue is the price that DNOs charge for services which should be determined by the direct costs of the services and the allocation of overheads to these activities. The level of overheads that a DNO allocates to connections will therefore have a significant bearing on the charges to the customer. For example, if a DNO chooses to allocate overheads to connections

on a marginal basis then this will make it impossible for a new entrant connections provider to successfully enter the market. This is clearly not the case in ENW's area. The inability to add a margin to efficient costs can also impact on competition and we agree that the netting of connections revenues from the RAV is an ill-conceived regulatory mechanism and the effective removal of any margin could create a potential barrier. Currently a DNO will quote at cost including properly allocated overheads, and there is no benefit to adding a margin as this would merely be netted off the RAV. In order to even match the DNO price, ICPs therefore have to make relative efficiencies on direct costs and overheads to fund a margin for themselves. The reason for competition developing in the ENW area may therefore have more to do with the correct allocation of overheads in the connection charge to customers.

- **Limits on activities open to new entrants** – There are good reasons for some work being non-contestable, such as safety, as highlighted in the policy paper. We have repeatedly argued that there should be limits to activities that are contestable and an unnecessary extension of contestability would also threaten the level of service that customers would receive in some of the most important parts of the connection process. The effort required by the industry to put in place appropriate levels of control outweighs the marginal benefit that can be achieved on a particular project. The example quoted in the paper of completing the final connection now has licence condition timescales in place for delivery and therefore should be less of an issue. Ofgem's focus should be on ensuring competition is brought to all DNO areas before looking to extend the scope of competitive activities where competition is already established.
- **Poor co-operation with new entrants** – We have had to invest a lot of resources to develop robust processes to facilitate the level of competition that now exists. These generally materialise as indirect costs and therefore companies such as ENW have had to maintain a higher level of indirect costs in developing and supporting a competitive market. In DNO areas where there has been little competition to date, such processes may not have been established and lack of staff awareness of competitive processes may inadvertently lead to poor co-operation which can hinder the development of competition. We would expect any direct evidence to result in an Ofgem investigation, and if such an allegation was substantiated, for appropriate action to be taken. A review by Ofgem into the processes and staff awareness in DNOs where there is no effective competition at present, as compared to DNOs such as ENW where competition exists, could indicate issues in this area which are inadvertently affecting competition.
- **Differing requirements country wide** – It is inevitable that there will be differences due to the history of the companies. There is a lot of standardisation though and work has been done to achieve standardisation where practical and appropriate.
- **Award of DNO contracts** – Much of the connections work is already undertaken by contractors and competition in connections is primarily about moving competition up the supply chain. There is already extensive competition in the provision of connections services to DNOs by contractors from which

customers already benefit and hence any further benefits of competition in connections may be small.

- **Start-up costs** – There are clearly costs associated with start-up such as accreditation. This is essential to ensure only competent companies are able to operate and as an important protection for customers appointing an ICP.
- **Lack of ICP engagement in the regulatory process** – We are somewhat surprised at this possible reason, given the active representation of ICPs at the Electricity Connections Steering Group.
- **Adoption agreements** – As there is competition between distributors in the adoption of assets, any standardisation of these terms needs to be mandated by Ofgem due to possible competition law issues. Any standardised adoption agreement should apply to all licensed distributors, not just the DNOs.
- **Inspection and Testing** – We do not see the inspection and testing regime as a barrier to competition in ENW's area, as we have made great efforts in this regard, particularly in ensuring there are no additional costs to the customer for inspection and testing should they select an ICP. This may not be the case in other DNO areas.
- **Shortage of Skilled Engineers** – The shortage of skilled engineers is an issue for the electricity industry in general and is a natural result of a long period of sustained cost cutting by DNOs.

We have not explicitly commented on what an appropriate level of regulated margin should be as we believe more work is required to define the mechanism whereby this would be applied. Any comparison of levels of margin needs to be done on a clear and comparative basis. This is a complex area and we are happy to work with Ofgem and other industry participants to develop this further. For DNOs such as ENW where competition is already well established, there is no need for regulated margins as competition will effectively cap the returns available. In these circumstances DNOs must, as a minimum be given the freedom to price below any cap level in a non-discriminatory manner. As mentioned above, the allocation of overheads and the timing of their recovery are the key to understanding and setting any margins. The regulatory treatment clearly needs consideration and the current approach to offsetting indirect costs from the RAV can be addressed at the same time as introducing a mechanism to ensure DNOs can retain a regulated or unregulated margin. We propose that all connections costs (directs and indirects) should be reported separately from other costs. We believe that for simplicity the same margin and cost treatments should be applied to both contestable and non-contestable elements of connections activity. If DNOs are not able to earn a margin from non-contestable activities it is likely that these services will receive the minimum level of management attention and there will be no incentive to provide customers with additional or enhanced services. Whilst we understand the principle that Ofgem may wish to apply, applying a margin only to the contestable element would seem overly complicated to manage and disproportionately protective of customers interests.

In terms of market segmentation, the categorisation by voltage of the customers connected rather than the voltage of the POC is inappropriate and impractical. A more sensible approach is to link the market segmentation to the categories specified in Appendix 1 of Standard Licence Condition 15. We do not think anything more complex should be introduced.

We believe that there needs to be a comprehensive set of competition tests which should include the measures indicated in the document. Our comments on the proposed competition tests follow:

- **Market share** – This is obviously important but the level needs careful consideration. Whilst we have a high level of competitive connections made in our area, any threshold needs to cater for any change in the mix of work caused by relative improvements in the DNO's performance, so that improved performance is not penalised.
- **Market penetration** – We have a significant number of active ICPs and IDNOs in our area but have some concerns that this is not totally within our control; for example, mergers or acquisitions could reduce the number of these participants. This should probably be considered as part of a market investigation to understand why competitors do not want to enter the market in a particular area.
- **Price** – It is not clear to us how Ofgem see an “average price metric” as a competition test unless it is part of a wider investigation into cost allocations and potential predatory pricing.
- **Investigation findings** – We agree that Ofgem will need to act on any adverse findings as part of any investigation they conduct. However, we believe that the competition tests need to be a series of easily measured metrics that can be reviewed on a regular basis. We therefore do not think that investigation findings should form part of the explicit list of competition tests as Ofgem will take appropriate action dependent on their findings.
- **Customer awareness** – We support the principle that the level of customer awareness of competitive alternatives should form part of the competition tests. However, until details are finalised we have some concerns how robust this measure would be. Whilst the number of competitive quotes that we issue is significantly higher than many DNOs, we are always striving to reduce the number of quotes issued to minimise inefficient, abortive work, eg by getting the developer to apply for a POC rather than deal with multiple ICP applications. We would not wish to introduce any perverse incentives that penalise behaviour which improves the effectiveness of competitive process.
- **Facilitation of competition** – We would support having LV live jointing as an initiative that facilitates competition as this is a clear pass/fail test and we believe has been a key aspect that has encouraged the competitive market in our area. Quality of website information is a much more subjective measure and therefore less appropriate.

- **Complaints** - We would support the use of complaints and suggest that the definitions recently introduced as part of the CEAR legislation would be more appropriate than Ofgem/Ombudsman referrals, which are less representative of the wider DNO performance.
- **Compliance with SLC 15** – We would agree that compliance with this licence condition is a sensible measure.

Overall the basis of the competition tests should be on a threshold of loss of market share, together with an aspect of customer awareness, level of customer complaints and compliance with SLC15 as a basic requirement.

As we have previously shared with Ofgem, we have had similar work undertaken on our market by economic consultants IPA, which has identified that competitive markets exist in our area and justifies the ability to earn a margin now rather than waiting until the start of DPCR5. We believe that we would pass all of these tests already and therefore believe that we should be able to be allowed to make a regulated return from April 2008 rather than delaying this to April 2010 as Ofgem have proposed. We believe that there should be no delay in Ofgem introducing this positive recognition for the competitive market that has been created in the North West as ENW have not had any recognition of the higher levels of indirect costs that it has incurred in supporting this market. We are confident that we will be able to pass any reasonable tests that Ofgem define.

This approach should be available to all DNOs from April 2008, but be conditional on meeting the competition tests when finalised by Ofgem.

### **3.7.2 Connections provided on a non-competitive basis (3.28 – 3.30)**

It is only appropriate to bring further customer protection into areas that Ofgem consider are not open to competition and where there is evidence that customers are being disadvantaged or receiving poor service. Ofgem's policy paper refers to "a strong case for rolling out and strengthening regulation" but does not articulate the case. We presume that this is based on the volume of complaints identified in Table 3.2 but these are very different from the levels of complaints we experience in the ENW area.

There should be no extension to regulation in competitive activities even where a customer chooses the DNO (ie selects the DNO from several service providers in a competitive market), as this undermines the principle of allowing competition to be preferable to regulation in controlling markets. As such, the introduction of further safeguards for customers needs to be regional to reflect that competition is providing protection for customers in some areas whilst not in others. Where there is no evidence of customer dissatisfaction, eg such as the low level of customer complaints that ENW receives, then adding further regulation in these regions is inappropriate, and potentially adds extra costs for customers whilst not creating any additional benefits. Imposition of licence conditions may not be in the customers' best interests as it can alter the behaviour of a DNO from seeking to provide excellent customer service to seeking to use the "rules" to minimise its exposure, for example by using strict interpretation of rules or guidance. In considering the options proposed by Ofgem:-

- **Option 1 - Extending regulations** - In regions where the level of customer service warrants additional regulation, we believe the introduction of additional guaranteed standards of performance relating to the time taken to provide a quotation to customers and the time taken to make the connection should be considered, with targets and definitions similar to those in the existing standards of performance.
- **Option 2 - Price regulation** – We would be happy to work with Ofgem to try to develop a simple mechanism which facilitates standard pricing for markets where competition will not develop. It is for Ofgem to determine if the approach developed is then compliant with competition law. As we identified earlier, how DNOs allocate overheads to this work will be a key component in the make-up of the charge to the customer and price capping of a small segment of connections activity may simply result in DNOs reallocating overhead costs. With regard to the specific comments concerning unmetered supplies, we are working closely with Local Authorities in our area to make processes as efficient as possible and to share any efficiency improvements but we would point out that that cost increases may be a result of inefficient practices by some Local Authorities, for example issuing orders where street lamps are not ready, leading to abortive site visits.
- **Option 3 - Price accuracy** – We currently compare outturn with estimated costs as part of our normal business to ensure we are accurately covering our costs and find a close correlation between them. We aim to issue fixed price quotes to customers where the risks are known and to minimise variations. We find that customers generally prefer this price certainty, however for larger projects the uncertainties at the time of quotation can lead to very large risk premiums and indicative quotations are generally in customers' interest. We are not clear how Ofgem would envisage such a mechanism would work and how it would differ from the existing determination route that currently exists for customers. We have no evidence that accuracy of quotations is an issue for customers and do not consider this to be appropriate area for additional regulation.
- **Option 4 - Cost efficiency incentive** – We maintain that the operating model we have adopted and the fact that we operate in a competitive market for connections means that there are strong drivers on delivering cost efficiencies and that these are passed through to customers. If Ofgem accept that ENW satisfy any competition tests set it sets, we would be seeking to earn any margins through additional cost efficiencies. This would result in charges to customers being maintained rather than simply being increased to create a margin. We are supportive of developing a sensible incentive but recognise that this needs to be aligned to the mechanisms for determining regulated margins and the issues of overhead allocations identified previously.

### 3.8 Guaranteed standards of performance (3.31)

We support Ofgem's overall proposal that the performance standards remain unchanged and that the penalties are increased in line with inflation. A number of changes were made to the Guaranteed Standards in recent years to deal with a

severe weather situation and there is no evidence to suggest that there should be any new standards introduced. The level of GS payments remains broadly consistent with annual DUOS charges and as such is effectively an annual money back guarantee for those customers subject to poor service.

We are particularly pleased to note that there is no intention to extend the GS scheme to include compensation payments linked to customers' potential consequential losses. It remains our view that these risks are for customers to manage. We comment further on non-guaranteed standards approaches to addressing business customers' concerns in the IIS section of our response.

We note Ofgem's comments on complaint handling and the possibility of a new standard in the future depending on how CEAR is implemented. We would be concerned if there was a wide discrepancy between companies under the new CEAR standard. Some companies may perform/adapt much better and quickly than others to the CEAR standard and it would be disproportionate, if a small number of DNOs performed badly in the first year or so, for Ofgem to impose a new Guaranteed Standard on all companies. Given the recent introduction of a whole new consumer representation structure, we believe that Ofgem should wait a reasonable period of time before considering any new standards.

### **3.9 Customer Service Reward Scheme (3.32 – 3.34)**

We support Ofgem's overall proposal with regard to the customer service reward scheme as it provides a useful opportunity to demonstrate the work that we do to enhance the service we provide to our stakeholders. We agree that the value of the scheme should remain at £1m. The value of the scheme does not need to be large as in the main larger incentives to improve service that come from elsewhere. We support the proposal to refocus on the three areas of:

- Communication with worst-served customers,
- Approach to ongoing stakeholder consultation, and
- Assistance for other categories of customers such as vulnerable customers who only have electricity.

We believe however that there could be more sharing of best practice so that ideas can be adopted by other DNOs. On a wider basis, Ofgem should consider a wider publication of the details of all DNO submissions and possibly an annual workshop where DNOs could present to each other and facilitate the sharing of best practice.

### **3.10 Quality of service interruptions incentive scheme (IIS)**

#### **3.10.1 Return on equity exposed to the IIS (3.36)**

It is our view that the overall current level of business risk exposure to the IIS performance incentive scheme is appropriate and should be maintained at three percent of base revenue. However, the current symmetry of performance bands around the targets represents a significant downside risk. It is easy to foresee a set of circumstances which cause the penalty cap to be hit for both CI and CML in any one

particular year, particularly when one considers the consequences of EHV or 132kV events. It is much less obvious, given that targets are largely based on historic performance, to see circumstances in which the cap on IIS rewards would be achieved.

### **3.10.2 Long Term Objective (3.37 – 3.38)**

We broadly support the longer term objectives outlined by Ofgem. To date, we have developed detailed connectivity models which facilitate accurate estimates to be made of customers affected by faults on the network. We accept however, that this approach is not accurate in all instances and in certain cases the exact customers affected by faults will not be known. These inaccuracies are considered to be very small in number and largely as a result of faults at the LV voltage level, particularly where there is overlap between HV and LV fault events.

We regard the development of LV connectivity models as one of the major benefits of IIS. This initiative has driven forward DNOs' understanding of network issues considerably, resulting in significant improvements in customer service over the past 6 years. We believe that it is appropriate to continue making further improvements to the accuracy of these models to unlock future potential benefits from initiatives such as smart metering systems and low voltage embedded generation. The introduction of smart metering will not in itself enable accurate customer numbers associated with individual faults to be defined; detailed connectivity models will continue to be required to accurately use such data.

The introduction of smart metering provides a potential opportunity for DNOs to obtain the real-time information identified by Ofgem. DNOs are currently engaging with DECC regarding the network-related specification requirements for smart meters including real-time interruption indications and reporting. The costs of such specification requirements, together with overall implementation costs, need to be assessed by appropriate cost-benefit analysis.

We are already planning web-based solutions which will provide greater information to customers regarding the current fault situation on the network, supported by detailed information on repairs and repair times.

We are keen to work together with Ofgem and the wider Industry towards the stated longer term objective. We do not believe however that a licence condition is a necessary or appropriate mechanism for ensuring that this objective is met.

### **3.10.3 Duration of the scheme (3.39 – 3.41)**

#### **3.10.3.1 Longer Term Incentives and Targets**

We are acutely aware of the issue of regulatory uncertainty associated with the benefits of investments beyond the current price control. The current five-year arrangements for agreeing and setting targets and associated incentive rates can result in investment timing issues as the IIS rewards are effectively bounded within a price control period; we welcome Ofgem's recognition of the need to provide longer term investment certainty.

The issue of longer term targets is potentially very complex and DNOs are likely to have differing views depending on their current performance position. We would find it difficult to accept longer term performance targets without knowledge of the wider capex and opex provision as the ability to either maintain or improve performance is directly linked to the amounts available to invest.

An alternative approach could be to consider the effect of the IIS target ratchet. Since historic performance improvements are locked in when setting forward targets, DNOs see reducing benefits from investments throughout the current price control period.

One way to avoid this would be to replace the step-change of the ratchet with a glide-path, such that the five-year targets are set at a gradually reducing level from the current target level down to the current average level by the end of the subsequent price control period. This mechanism would ensure that DNOs are able to account for benefits of investment beyond the price control period and would act to reduce the investment timing issues identified.

### **3.10.3.2 Past and Future Capex and Targets**

We consider that it is now appropriate to review the case for further capex allowances for CI gap closure in cases where there is a gap between a DNO's current performance and the performance suggested via benchmarking. Previously this measure was perhaps not unreasonable given that wide range of starting positions, however, this now needs to be considered in the context of the wider capex strategies adopted by DNOs during DPCR4. In particular, the provision of additional capex in DPCR5 could be questioned if a DNO has claimed capex efficiencies for DPCR4 whilst delivering CI performance at worse than benchmark levels.

### **3.10.4 Incentive rates (3.42 – 3.43)**

We agree in principle with the proposal to move to a scheme whereby all DNOs share equal incentive rates for customer interruptions and for interruption duration, since this approach is consistent with setting rates on the basis of the assessed cost to customers of supply loss. However it is also important to recognise that the existing arrangements have delivered significant performance improvements since their inception and some consistency of investment signals needs to be preserved. This suggests that a transition to more cost reflective arrangements over a period of time may be appropriate.

We also agree with equalising relative company risk. RORE gives a mechanism for assessing overall company risk exposure to incentive schemes and setting caps/collars on individual schemes. It may not be essential to balance risk exposures to IIS precisely, so long as overall company risk exposure is broadly consistent. Therefore, we suggest that for DPCR5 rates are moved towards the overall company average by 50% of the difference from the average.

### **3.10.5 Refinements to the IIS (3.44 & Appendix 7)**

#### **3.10.5.1 HV**

We believe that the existing disaggregation methodology is generally robust and reliable. Whilst we accept that there may be scope for alternative mathematical approaches, the effects of these are generally considered to be minor for the majority of customers and are unlikely to significantly affect targets.

We are broadly in agreement with Ofgem's proposal to use four years' data for the purposes of identifying HV performance benchmarks. However, it is important to not lose sight of the potential affect of annual volatility alongside the influence of investment on performance.

Our comments and observations on the detailed modifications to the HV benchmarking methodology are set out below.

#### **3.10.5.2 L0 Band**

We do not have strong views on the options presented for the treatment of zero length circuits but on balance would argue for the band to be removed and instead for all such circuits to be categorised as either UG1A or UG1B as appropriate.

#### **3.10.5.3 Customer density**

It is very difficult to comment on the proposed changes to the benchmarking methodology based upon the information presented. We need to understand the rationale behind the proposed modifications and the effects that such a change would have on the respective benchmark values.

#### **3.10.5.4 Band dominance**

We are broadly in agreement with the proposed fault rate weightings.

#### **3.10.5.5 Linear length correction factor**

We welcome the proposal to perform further analysis, since there is insufficient information provided to allow a complete understanding of the issue. The suggestion of an inverse relationship between fault rate and length appears counter-intuitive and we would need to see the analysis repeated for a number of years to be convinced that this is a genuine effect.

#### **3.10.5.6 Calculating upper-quartile**

The current approach of determining upper quartile performance in each of the 23 bands is a best-of-the-best approach which is an unrealistic performance objective. We support the proposal to modify this approach to base it on the upper-quartile of the summed performance, and believe this is a reasonable and more realistic alternative.

### **3.10.5.7 LV Benchmarks**

We strongly disagree with the proposal to combine LV underground and overhead into a total LV measure as this will produce unfair allowances due to the differing proportions of overhead and underground circuits between DNOs and the shorter repair times associated with overhead faults.

Our analysis of ASID by MEI indicates that those DNOs with larger proportions of LV OH network consistently attain a lower overall LV ASID; this is driven by shorter repair times for OH faults. ENW, with 92% of LV network underground, would be disadvantaged by approximately 12% if an average (80% UG/OH) network mix was used for target setting.

Ofgem state the principle reasons for a total measure to be concerns regarding the availability of reported data. We disagree with this and suggest that the separation of LV by overhead/underground is a lot easier than separation by mains/services as is currently required; any issues could be overcome by appropriate modification to the RIG. We suggest that, as a minimum, Ofgem make appropriate modification to the collection of future data to facilitate the split of the LV measure in time for DPCR6, particularly given the increasing importance of LV performance.

### **3.10.5.8 EHV/132kV**

As the overall level of performance improves, one-off exceptional events occurring at EHV become increasingly important to customers and DNOs. Building upon previous discussions we are keen to finalise a treatment of liabilities associated with forced outages during periods of construction and maintenance activity. 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 their 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 experiences an unplanned 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 in 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.

DNOs are encouraged to adopt costly mitigation measures during delivery of large scale capital projects, whilst the probability of an event occurring remains low.

Although it is right that the DNO makes these judgements based on economic drivers, we believe that the balance of risks in certain circumstances could be adjusted to ensure that customers do not see the costs of the associated risks crystallised into significantly higher capital unit costs.

### **Guaranteed Standards**

We recommend 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 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. We consider the exposure of the total IIS reward/penalty to a single event to be undesirable and we would encourage Ofgem to consider options for containing this risk further, our proposal being to consider the adoption of a separate scheme for primary (ie in the range 33kV to 132kV) system failures. 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. We propose that the cap be proportional to the contribution made to current overall targets by the primary systems.

The above proposal differs from Ofgem's proposed application of an IIS cap per incident at these voltage levels; however, it is easy to see how these proposals could be aligned. We would welcome the opportunity to further discuss both these proposals in more detail.

#### **3.10.5.9 Revised Draft Targets 2014-2015 Benchmarks**

We welcome the proposal to modify the calculation of CML targets for frontier CI performing companies. We are pleased to see that Ofgem have recognised the double ratchet effect which caused particularly onerous CML targets for DNOs at the frontier with respect to CI performance. The draft unplanned targets for CML, whilst remaining challenging, are now more realistic representing current average performance with realisable year on year improvements.

However, as we state in our response on Longer Term Incentives and Targets, we believe that the current approach to the setting of CI targets is worthy of further review. The application of a straight step-change in targets is considered to be unfair and has the effect of encouraging perverse investment decisions.

There are a number of issues which lead to this view. Firstly, the CI ratchet wrongly assumes that the distribution of equipment fault rates (particularly HV feeders) will remain constant such that there will be no change to underlying performance - all else being equal. The reality is that, without intervention, overall fault rates will

deteriorate. Although performance-related network investments will have mainly targeted poorly performing assets such that these assets can no longer be considered poorly performing from a customer perspective, their fault rate will now be addressed separately largely driven by fault repair costs. These particular assets will be replaced on a (poor customer) performance ranking over time by others elsewhere on the network whose condition and therefore performance has deteriorated. In order to avoid a worsening in overall quality of supply performance from that achieved by performance-related network investments, it is necessary to continue to deploy appropriate post fault mitigation (such as distribution remote control devices and network automation) on these assets to maintain CI performance in line with previous years.

Secondly, the sound performance improvements made by ENW during DPCR4 have been largely funded by shareholders. Since we have continued to outperform CI benchmark performance, no specific capex allowance is made by Ofgem for gap closure thus our shareholders have funded investments by reinvesting capex efficiencies and hence forgoing any potential efficiency rewards. By applying a CI ratchet in the manner proposed, Ofgem are closing off all future returns associated with DPCR4 QoS investment to shareholders; a situation which is particularly inequitable for investments made in the first three or four years of the five year price control period.

It is our view that it would be more appropriate for Ofgem to lessen the ratchet to ensure that all future benefits are shared on an equitable basis between shareholders and customers. To overcome this ENW would propose the following modifications to the CI target setting methodology.

We suggest Ofgem replace the current step change in CI targets between price-control periods where appropriate with a glide path approach whereby targets are reduced on a linear basis. As such targets would be reduced annually by 20% of the difference between actual and target performance such that by the end of the new price control period the CI target is equal to the average performance at the end of the previous price control period.

#### **3.10.5.10 Pre-arranged Interruptions**

The existing methodology for determining pre-arranged allowances has resulted in significantly varying levels between DNOs. Additionally, the utilisation of these allowances has been mixed resulting in an apparent over-allocation of allowances for some DNOs; however 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. Our view is that network factors are the most significant determinant of differentials between DNOs' underlying requirements for planned interruptions, but that this base level is driven by the volume of work being undertaken by the individual DNO.

We suggest that appropriate allowances for planned interruptions should take account of forecast network activities. Furthermore, we would support the introduction of a driver resulting in changes to allowances subject to changes in planned activity.

It remains logical that the incentive rate placed upon these interruptions is set lower than for unplanned interruptions due to their planned nature.

#### **3.10.5.11 Treatment of exceptional events**

We do not agree that all large one-off events should be excluded irrespective of cause. Instead, we suggest that existing thresholds be retained such that for events which are shown to be in excess of this threshold all the resulting CIs and CMLs are excluded but that their exclusion be subject to the introduction of a materiality threshold.

Sensible investments have reduced the volume of interruptions arising from weather related events, thus suppressing the customer impact of a storm; however the repair volumes and costs have remained largely unchanged. Such events are not within the DNO's control and as such should continue to be exempt. It may be preferable to introduce a de-minimis level (materiality threshold) such as the first 20,000 CIs.

The issue of large one-off events associated with large scale capital projects is addressed in the section of our response relating to EHV/132kV, and we welcome Ofgem's continued consultation on this issue. Of the options presented by Ofgem, we consider option 2 (the application of a cap) to be most appropriate; the cap should reflect the current level of EHV/132kV performance.

#### **3.10.5.12 Non-domestic customers**

We comment below on the proposal to introduce new reporting requirements on DNOs to identify whether interrupted customers are domestic or non-domestic.

We already take steps to ensure that control room staff are aware of the network location of key customers. We individually identify all HV connected customers using our connectivity model, and this enables a high degree of accuracy in fault recording for such customers. Our performance reporting could be modified to show relevant information on an individual basis.

Business customers connected at LV are identified by MPAN against a unique connection point. Identification of the MPAN should allow us to define a customer as domestic or non domestic through consideration of the relevant tariff, however this would clearly require appropriate IT investment.

With regard to the potential introduction of tailored services for non-domestic customers as standard it should be noted that previous discussions have indicated that other than PSR and protected customers all others should be treated equally. We therefore use a common response approach regardless of classification or tariff and treat the restoration of all customer supplies as an equal priority.

### **3.11 Worst Served Customers (3.46 – 3.56 & Appendix 7)**

We support the proposal not to make any changes to the Guaranteed Standards of performance as a means of addressing the performance of networks in areas of worst-served customers. We agree that any changes to GS payments would not materially affect performance to these customer groups. It is considered preferable for DNOs to be encouraged to invest in networks and other solutions having the effect of improving the reliability of supplies to worst-served customers. We agree that a specific allowance to improve the reliability of supplies to worst-served customers is a reasonable and effective way of dealing with this issue in the short-term. We are keen to engage further with Ofgem regarding the possible future introduction of an incentive mechanism to either compliment or replace the allowance at such a time as the necessary data becomes available.

We agree with the proposal to base the definition of worst-served customers on customer interruptions. Given the current availability of data and the level of understanding of the issues it is appropriate to focus initially on the performance of HV networks and to assess performance over an average of three years; however it would be appropriate to revisit this approach as we gain better understanding of the issues and the options available to achieve effective improvements in performance.

We note that the proposed allowance represents an annual expenditure of the order of £640k per DNO. We also note the separate proposal to introduce efficacy and performance tests against which any investment in this area will be judged. We are similarly keen to ensure that value for money is obtained in this area, but are concerned that the introduction of a cost cap will unreasonably restrict our ability to invest on behalf of the very worst-served customers. It is well understood that many worst served customers are located at the extremities of the HV network in rural areas. Their performance issues will likely require refurbishment or reinforcement of networks, and as relatively few customers benefit from individual schemes, the £1000 per customer will be insufficient. We encourage Ofgem to reconsider the level of this cap, our assessment being that a level of around £2000 per customer would be more appropriate.

It may also be possible to consider use of HV generator connection points as an economically efficient solution to reduce the duration of interruption to worst served groups – whilst this would not reduce interruption frequency it could significantly reduce the duration of supply loss.

## **4 Networks**

### **4.1 Chapter Summary**

One of the key challenges to the DNOs after the publication of the HLFBPQ data was to provide justification to counter the expectation that the scale of the total investment programme would be cut back. We believe that this expectation conflicts with other messages contained within the networks chapter of the Policy Paper. We submit capital programmes based upon the long term requirements of the network using a risk-based approach. These long term demands, whilst sensitive to short term economic shocks, are unlikely to alter materially, although they may allow for some project deferment. Prescribed “cuts” in programmes due solely to political concerns place the network at increasing risk. The utilisation of an outputs-based approach should allow the DNOs to submit plans to Ofgem which reflect the actual needs of a network with agreed outputs and therefore, assuming that the risk profile is acceptable, not susceptible to undue regulatory interference.

#### **4.1.1 Nature of the price control settlement and behaviours**

We agree with Ofgem’s identification of the behaviours that should be encouraged during DPCR5. With the exception of delivering a pre-defined set of outputs, these are the behaviours we believe the DPCR4 settlement encouraged, and that we have exhibited as we fulfilled our network obligations during DPCR4.

#### **4.1.2 Performance against the DPCR4 settlement**

A strong customer service performance from ENW, ahead of regulatory targets, has been delivered consistently across DPCR4 at a very efficient cost level that will directly reduce prices for customers in the future. In the face of significant unit cost pressure we have succeeded in holding both operating and capital costs down at a very efficient level.

Overall activity levels and expenditure in connections have been significantly higher than forecast at the end of DPCR3; resulting in a considerable churn in the associated reinforcement programme whilst reducing the measured net expenditure levels due to the treatment of indirect costs associated with this additional activity. We recognise that the expenditure levels measured under RRP rules show an underspend against allowances, but these figures are unrepresentative of investment undertaken due to their being depressed by Ofgem adjustments.

We have spent significant time and effort prior to and during DPCR4 in developing asset management techniques to target our investment (Condition Based Risk Management). The techniques we have developed have allowed us to maintain the level of network performance as indicated by underlying fault rates and our analysis of condition and non condition faults. We have actively managed our expenditure programmes to ensure that network risk has been held at a constant level throughout DPCR4.

We will continue to pursue efficiency improvements and are highly incentivised to do so under RPI-X regulation. Regulatory anticipation of such improvements through techniques such as total factor productivity does not change the nature of these incentives; it simply affects the speed of capture of improvements for customers.

#### **4.1.3 DPCR5 forecasts**

Our HLFBPQ forecasts were based upon high level assumptions, so there are a few changes as more detailed assumptions are worked through. As our direct expenditure programme is greater than DPCR4, indirect costs will increase, but not on a directly proportional basis. CBRM and our minimum whole life cost approach indicate the need to increase volumes of some specific maintenance activities, and this is a significant driver of our promotion of the proposal to align opex and capex incentives.

The DPCR5 LRE programme has been constructed on the basis of reinforcement capex solutions to identified network constraints. However, we recognise the potential cost and environmental benefits of Demand Side Management (DSM) as an alternative solution.

We are exploring DSM and have reviewed our programme to identify where DSM alternatives could be utilised. The creation of a regulatory framework to encourage DSM provides another argument for the equalisation of opex and capex incentives.

Our FBPQ discusses the requirements of the business in terms of capital requirements and workforce renewal requirements. The FBPQ includes a £20m workforce renewal programme for DPCR5 to address these issues in addition to the £6.5m planned in DPCR4.

#### **4.1.4 Managing volume uncertainty**

We support Ofgem's proposal to move from a revenue driver as a means of managing volume uncertainty of demand related investment. We propose bespoke demand (MVA) drivers for identifiable areas of the network, supplemented by a trigger process for high materiality projects.

#### **4.1.5 Managing input price uncertainty**

A major challenge for the DNOs in DPCR5 is the retention and recruitment of skilled labour, and we believe that shortages will lead to annual salary increases exceeding the rate of inflation. Whilst we will attempt to mitigate these cost increases through intelligent procurement practices, the impact is likely to increase DNO costs.

Commodity prices have fallen considerably since the HLFBPQ but this change will not necessarily be reflected in similar movements in materials contract prices underlying the FBPQ. Input prices over the remainder of DPCR4 and DPCR5 are being driven by a combination of commodity price increases and the transaction price risk driven by falling exchange rates. Ofgem need to develop a pass through or trigger to mitigate the risk associated with these costs to allow the IQL and outputs mechanisms to operate effectively.

#### **4.1.6 Equalising incentives**

We support the equalisation of capex and opex incentives. Of the three options identified in the policy paper we support fixing the proportion of costs which enter the RAV. A two stage process is required where the IQI is applied first on the appropriate areas of expenditure; the resulting incentive rate for each DNO should then be applied to all expenditure. The percentage of expenditure that needs to be expensed to ensure the financeability of the individual DNO can then be determined. It is important to remember that there are core cash requirements for DNOs which must be financed by the price control settlement.

#### **4.1.7 IQI**

Ofgem's modelling and IQI assessments are likely to give some indication as to the appropriateness of the overall scale of company submissions and hence the need or otherwise to introduce additional scrutiny in the form of more detailed scheme analysis and/or reporting on physical activity. It may be appropriate to amend the IQI mechanics to reflect not only the inherent riskiness of lower forecasts, but also the degree of output commitment concomitant with those forecasts

#### **4.1.8 Output measures**

A number of preferred approaches are emerging in the area of outputs; for example the use of health indices to indicate the condition of individual assets and the overall asset base. DNOs should be in a position to define some initial output measures with a broad indication of the effects of planned investment on them. In assessing the 'sufficiency' of proposed outputs this should be split into two; assessing the appropriateness of the proposed measure itself and assessing the appropriateness of the target. Appropriateness of the measure can be determined by tests of:

- Measurable – the proposed output needs to have a countable metric
- Replicable – can be compared across time and/or across DNOs, and
- Controllable – DNOs have a measure of control over the outcome.

In addition, we suggest a judgement could be formed of:

- Relevance (to the outcome being pursued, public policy objectives etc.)
- Timeliness – ie leading, lagging
- Strength - can an incentive rate be determined which is reflective of the externalities? ie providing the correct economic signal, or is the incentive rate sufficient to drive behaviours?
- Detail – Ofgem should not have to micro-manage

There may also be a case to reward companies who are proposing more advanced metrics but taking some outcome risk due to their relatively early state of development.

#### **4.1.9 Cost Assessment and Comparative Efficiency**

We agree with Ofgem's intention to place more emphasis on individual company forecasts and the incorporation of regional requirements, but point out the inevitable diminution in comparability that will result. It is important to recognise that DNOs have been incentivised to improve efficiency as measured by the models utilised in DPCR4, and it will be important to repeat this analysis as a reference point. It is important that new models are developed to assess required spend that recognise the real drivers of costs and with the building block approach to allowance setting in mind. Ofgem need to be very mindful of how to index determined efficient costs for future volumes.

We urge Ofgem to recognise 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. It will always be necessary to use top-down analysis to assess the scope of cherry picking in more disaggregated cost models.

Additionally:

- Analysis must include all margins in all models to ensure a true comparison of the various business models..
- Allowances for storms must take into account the locational impact of storms and the impact of climate change on frequency of severe weather events.
- We do not believe that regional cost adjustments (outside of current arrangements) are justified
- We agree that apprentice costs should be modelled separately.

Care is needed when making international comparisons, as cost data needs to be captured on consistent basis to UK regulatory definitions, which are very different from international accounting standards.

#### **4.1.10 Assessment of investment requirements**

We support the approach of determining efficient unit costs and developing DNO specific forecasts of volumes of work required. Ofgem must engage closely with each DNO to develop a good understanding of the required volumes, particularly where they have developed CBRM type approaches which are superior to age-based models. Care is needed when comparing unit costs between DNOs because of differences in interpretation of unit definitions.

## **4.2 Answers to Ofgem's Specific Questions**

**Question 1: Have we identified the right behaviours for DNOs? Are there others which should be included?**

See section 4.3 of our response.

**Question 2: What action should we take where a DNO has deferred investment and created a backlog in DPCR4?**

See section 4.4 of our response.

**Question 3: What approach should we manage to deal with volume uncertainty?**

See section 4.7 of our response.

**Question 4: What approach should we take to price uncertainty?**

See section 4.8 of our response.

**Question 5: Should we be looking to equalise incentives for opex and capex? If so, what approach should we adopt?**

See section 4.9 of our response.

**Question 6: Do you consider that we should make refinements to the IQI? If so, what changes should we make?**

See section 4.10 of our response.

**Question 7: What action should we take where DNOs provide insufficient output information as part of their February FBPQ?**

See section 4.11 of our response.

**Question 8: Do you agree with our proposed approach to assessing network operating costs and indirect costs?**

See sections 4.12 and 4.13 of our response.

**Question 9: Do you agree with our proposed approach for assessing network investment?**

See section 4.14 of our response.

**4.3 Nature of the price control settlement and behaviours (4.7)**

We are supportive of all of the behaviours listed in paragraph 4.7 being behaviours that Ofgem are seeking to encourage during DPCR5. With the exception of delivering a pre-defined set of outputs, these are the behaviours we believe the DPCR4 settlement encouraged us to undertake. We can demonstrate that these are the behaviours we have exhibited as we have fulfilled all of our obligations and managed our network during DPCR4.

We are pleased that Ofgem recognise that the current regulatory accounting framework may influence the determination of the efficient option available to the DNO. Ofgem and DNOs should seek to create an alignment between the efficient option and the most socially economic option. The discussions about fixing the proportions of expenditure entering the RAV represent an opportunity to allow DNOs to think more expansively when considering replacement options.

#### **4.4 Performance against the DPCR4 settlement (4.8 – 4.26)**

A strong customer service performance from ENW, ahead of regulatory targets, has been delivered consistently across DPCR4 at a very efficient cost level that will directly reduce prices for customers in the future.

##### **4.4.1 Comparison to Regulatory Allowances**

Overall activity levels and expenditure in connections have been significantly higher than forecast at the end of DPCR3; resulting in a considerable churn in the associated reinforcement programme whilst reducing the measured net expenditure levels due to the treatment of indirect costs associated with this additional activity. We recognise that the expenditure levels measured under RRP rules show an underspend against allowances, but these figures are unrepresentative of investment undertaken due to their being depressed by Ofgem adjustments:

- Connections Volume Changes
  - Irrespective of the level of margin earned by DNOs from connections activities, all DNOs have their RAVs reduced because of the difference in treatment of indirect connections costs and indirect connections contributions. In the ENW region we have observed a doubling in the volume of connections contributions when compared to the forecasts made at DPCR4. Indirect costs incurred, that have been booked against expenditure rather than RAV under Regulatory Reporting Pack (RRP) rules are significantly higher than Ofgem's implied forecasts. As the RRP rules assume that a fixed percentage of all connections costs should be expensed, irrespective of the actual volumes, our RAV has effectively been depressed.
- Competitive Connections and Street-Lighting Gross Up
  - RRP rules also require the inclusion in regulatory accounts of all connections activities undertaken in the DNOs Distribution Services Area by any related party. The separation of direct and indirect costs results in 100% of the customer contributions being set against the capital programme, but only 52.6% of the indirect element of the costs being allocated to the capital programme. Competitive connections activities undertaken by the UU group outside any sub-contract arrangement with ENW, specifically for multi-utility connections have also effectively reduced our RAV. The same effect also applies to some street lighting contracts successfully secured via competitive tendering processes.
- Asset Disposals
  - Ofgem assert that where companies dispose of assets that they have acquired in the course of their distribution business some of the benefits of those disposals should be shared with customers. Accordingly, 100% of the proceeds of operational asset disposals and 23.5% of the proceeds of non-operational asset disposals are disallowed from the RAV, enabling the company to keep 76.5% of the benefit. We note that this is consistent with Ofgem's allowance of 23.5% of the costs of non-operational assets in the RAV.
- Excluded Services Revenue

- Ofgem forecast how much revenue companies were likely to earn from excluded services at the start of the price control period. Where companies out-perform this forecast, 23.5% of the margin is shared with customers through a RAV reduction mechanism. This is consistent with the assumption that all the costs are direct opex and included in NCCF.
- Related Party Margins
  - The removal of related party margins from the calculation of RAV additions depresses capital expenditure when compared with regulatory allowances. We accept that margins should be excluded for the period when the company was part of United Utilities Group. After the sale of the business, margins earned by the asset service provider should not be removed from RAV and from comparison with allowances. Under the new operating model, the cost of the margin is only incurred where it is funded by additional efficiencies.

All of these adjustments are required within the Ofgem rules to enable the calculation of RAV additions. However, it is not appropriate to include them when evaluating the expenditure incurred against capital allowances.

#### **4.4.2 DPCR4 Efficiency Programme**

We have continually improved the value-for-money delivery of our investment programmes through the implementation of a number of major initiatives in the areas of direct activities and engineering support.

We have spent significant time and effort prior to and during DPCR4 in developing asset management techniques to target our investment (Condition Based Risk Management). We have carried out detailed asset condition surveys which have been used to ensure efficient and targeted investment across a number of the main asset groups. The techniques we have developed have allowed us to maintain the level of network performance as indicated by our measures of Asset Health Indices, as well as underlying fault rates and our analysis of condition & non condition faults. We have actively managed our expenditure programmes to ensure that network risk has been held at a constant level throughout DPCR4. This has required constant assessment and refocusing to the highest risk areas, bringing forward a large number of schemes previously not anticipated in DPCR4 and deferring others.

We will continue to pursue efficiency improvements and are highly incentivised to do so under any form of RPI-X regulation. The predicted level of capex returns illustrated in the return on regulatory equity model has been attained through the behaviours encouraged by the regulatory framework. The proposed alignment of incentives will provide new opportunities to provide innovative solutions for traditional capex activities.

At the start of DPCR4 we set out planned levels of investment with targets for proactive asset replacement and anticipated outcomes of condition based failures and non condition based failures. The results of this plan are continually being reviewed and form part of our revised investment plans. In DPCR4, we have made numerous

capital efficiencies whilst managing the risk of the network. This including rescoping numerous expected DPCR4 projects including:

- Modification of Reyrolle L42 & L45 33kV switchgear (population: 145). Plant modification and civil refurbishment giving significant life extension at minimal cost,
- Modifications to the overhead line refurbishment policy, reducing refurbishment costs from £30k per km to below £20k per km.
- Changes to policy to ensure that automated / remote control is installed as part of asset replacement where justified based on a cost benefit analysis.
- Stuart Street Grid Transformer change (post-failure) where the opportunity was taken to change a planned reinforcement and asset replacement scheme to deliver a more efficient overall solution following the unplanned event.
- 132kV GIS Substation installation; improved designs and installation of control wiring significantly reducing unit costs.
- Targeted civil maintenance based on condition & risk.

In addition we have implemented an aggressive and comprehensive efficiency improvement programme across the entire cost base. In the face of significant unit cost pressure we have succeeded in holding both operating and capital costs down at a very efficient level. This programme has been supported by a selective severance and redeployment programme.

A streamlining of processes across connections and capital delivery has aligned accountability with delivery and allowed a reduction in indirect costs by up-skilling staff involved in project and programme management and project control areas. Savings have further been achieved through the application of leaner processes with non-value adding activities designed out of the process wherever possible.

Good progress has been made on the integration of supply chain activities. Integration of operational activities carried out by our internal staff and our network partners has resulted in co-location, integrated work scheduling, shared stores and combined delivery teams. There has been significant upward pressure on material and contract prices in the year but in a number of areas we have been able to secure tighter contracts, mainly for the delivery of services. Two good examples are fleet management and servicing costs and in the procurement of contract design staff.

We have reorganised the entire business structure and, following the successful implementation of both phases of our restructuring, have largely abandoned our previous multi-utility strategy to create a customer focussed distribution-only business. In 2005 we brought together the electricity aspects of asset management, asset operation and maintenance and asset construction to form a single Electricity Business Stream within the United Utilities Group. In April 2007, we implemented a new operating structure reflecting separate asset owner and asset service provider functions. This contractual arrangement provides clear commercial incentives to deliver efficient operations & maintenance, efficient capital delivery including new connections and improved customer service. This structure provides further impetus to drive out efficiencies and improve delivery, beyond the aspirations of the business plan for the

business when still combined. The legal separation of these businesses was completed in December 2007.

Some of the efficiencies made in the DPCR4 investment programme were reinvested to address emerging risks in relation to overhead lines. In 2007-08, we completed our detailed and extensive survey of the condition of network plant and overhead lines to secure the comprehensive asset data required to inform our Condition-Based Risk Management (CBRM) programme. One consequence of the improved data is an increased awareness of technical infringements of the new ESQC Regulations, particularly regarding clearances. The rectification of these, and other immediate priorities (such as pole changes), has commenced during DPCR4, contributing to a rise in HV and LV overhead replacement expenditure. Some of this additional expenditure has subsequently been recognised in Ofgem's 2008 Re-opener proposals.

#### **4.5 DPCR5 forecasts (4.27 – 4.42)**

Our HLFBPQ forecasts were based on high level assumptions, so there are a few significant changes as more detailed assumptions are worked through – some are reducing expenditure and some increase it. As our direct expenditure programme is greater than DPCR4, indirect costs have also increased, but not on a directly proportional basis giving efficiency improvements in terms of indirect cost for each pound of direct expenditure. A comprehensive overview of our DPCR5 forecasts has been included with our Forecast Business Plan Questionnaire submission.

Our Condition Based Risk Management model and minimum whole life cost approach indicate the need to increase volumes of some specific maintenance activities. Network risk can be managed by either replacement of the asset, refurbishment or increased maintenance expenditure. The regulatory treatments of the costs associated with each solution are considerably different and produce differing value drivers. Assuming an economically rational company will seek to maximise value and not place risk on the expenditure by incurring the cost and then seek appropriate recompense, the DNOs will currently favour capex solutions. The equalisation of the opex and capex incentives will encourage DNOs to utilise the most appropriate and efficient solution. The equalisation will also be a step towards the employment of Demand Side Management (DSM) schemes becoming a possible realistic alternative to reinforcement capex investment.

The current regulatory mechanism does not provide sufficient incentive to develop DSM solutions to network reinforcement needs. Therefore, the DPCR5 LRE programme has been constructed on the basis of reinforcement capex solutions to identified network constraints. However, we recognise the potential cost and environmental benefits of DSM and encourage the creation of a more supportive regulatory framework. We are exploring DSM and currently are developing a pilot project with a number of large industrial customers. Accordingly, we have reviewed our LRE programme to identify where DSM alternatives to the proposed reinforcement could be utilised. We are at an early stage of developing this approach, but are happy to share our progress and findings with Ofgem at any time.

DSM techniques can only resolve thermal, and possibly voltage, constraints on the network, driven in turn by maximum demand. Our analysis indicates that in the majority of cases the maximum demand is dominated by domestic load. We do not believe that under the current market arrangements we have the appropriate relationship, nor the technical tools to achieve a workable DSM scheme with domestic customers that would obviate or defer reinforcements.

Our forecast business plan questionnaire discusses the requirements of the business in terms of capital requirements and workforce renewal requirements. Analysis has shown that it is likely that circa 45% of the current workforce will leave the industry over the next 12 years. This combined with the increased investment requirements on the network provides a real challenge. The FBPQ includes a £20m workforce renewal programme for DPCR5 to address these issues in addition to the £6.5m planned in DPCR4.

In terms of the regulatory treatment of these costs, we assume that Ofgem will adopt the proposals to add a fixed proportion of costs to the RAV in DPCR5. We believe that this treatment is appropriate for workforce renewal costs. Future customers will benefit from the training of apprentices and therefore, in the interests of intergenerational equity, the costs should not be wholly funded by the present generation of customers.

#### **4.6 Dealing with Uncertainty**

All businesses face risk and uncertainty with regards the effect of exogenous events on their costs and revenues. Regulated businesses are no exception but the funding mechanisms in place to protect customers from monopolistic charging practices also restrict the company's ability to respond to these events. The magnitude of the costs associated with the event, the size of the headroom available to absorb the fluctuation, and the regulatory treatment of the risk are likely to determine the impact of any specific event. Whilst the first two elements are impossible to determine in advance of the event, the regulatory mechanisms/framework can be discussed and agreed which will reduce the impact of an uncertain event. The regulatory framework also has a significant effect on how these risks are allocated between the company, customers, shareholders and creditors. The way in which risk and uncertainty are treated affects a number of issues, including:

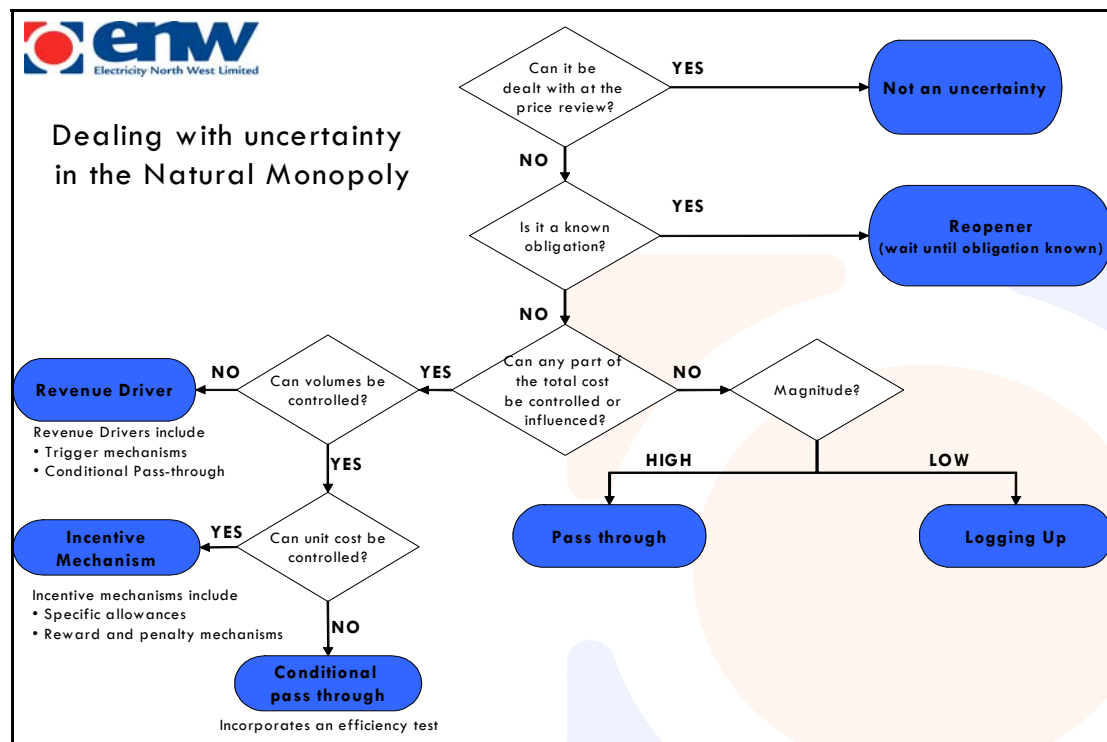
- the incentives on the regulated business to behave efficiently;
- the rate of return that the company requires to accommodate fluctuations in cash flow;
- the ability of the business to absorb cost shocks; and
- the price at which companies are able to raise risk capital as creditors will require a premium to accept greater risk.

In deciding how to allocate risk, the main principle to be used is that, as far as possible, risk should be borne by the party best able to manage it. Exposing a regulated business to risks it is unable to manage efficiently is unlikely to provide value

for money because it will increase the company's cost of capital above the efficient level (as the pricing of the risk will have to include a significant premium to reflect the additional exposure and inability to manage the impact).

The identification of the correct mechanism to respond to the risk is almost as important as the risk itself. Utilisation of an inappropriate funding vehicle results in an inefficient position for either the customer or company. The above measures may also introduce a level of risk depending upon your view of the certainty of recovery and appropriateness of the mechanism. It must be recognised that utilisation some of these measures only provide a limited degree of protection whilst others eliminate the risk altogether. The balance between protection of the regulated business and the retention of incentives to encourage managers to produce innovative solutions (which will be passed on to customers) also needs to be carefully considered.

We are attempting to develop a framework to identify new risks in DPCR5 and to understand the most effective regulatory treatment for each area of uncertainty. The following flow chart sets a framework for the discussions.



The key issues behind this flow chart include:

- It is important to deal with uncertainty in a predictable manner. Setting out a framework for dealing with uncertainty ensures a consistent approach.
- The tools utilised in this framework ensure that additional risks are efficiently handled within a price control. Whilst there have been criticisms of complexity of the regulatory regime, it is more desirable than the alternative which is an inefficiently priced WACC.

- The mechanism presupposes that risks are identified at the price control review. The regulatory framework must be sufficiently flexible to allow significant unidentified cost shocks to be efficiently recompensed.

#### **4.7 Managing volume uncertainty (4.44 – 4.48)**

We support Ofgem's proposal to move from a kWh revenue driver as a means of managing volume uncertainty of demand related investment; we believe that kWh sales represent a poor proxy for changes in capacity and also believe that from an environmental perspective, network companies should not be rewarded for increasing the number of units crossing the network.

We see a volume driver for new connections reinforcement as possible but we would recommend at least disaggregation of the connections volumes across voltage levels and separate drivers at each level to reflect the differing costs associated with reinforcement across the levels.

In respect of general reinforcement we agree with the proposal to introduce bespoke demand (MVA) drivers for identifiable areas of the network, supplemented by a trigger process for high materiality projects (in the same way that, for example, NGET's 'revenue drivers' are tailored to zonal conditions). We are interested to understand the exact operation of the proposed capex driver and would stress that the operation should recognise the significant lead times associated with reinforcement projects. Specifically, the trigger mechanism should take cognisance of the 18-24 month lead time associated with large grid and primary projects. We would caution against adoption of simplistic model outputs as reinforcement drivers and measures of network risk. It is our experience that modelling techniques should be used as a 'stress' test of the network and identified issues must be confirmed by a detailed study of the 'stressed' area. We comment in the final paragraph of section 2.5.3 of this response on the potential roles of DSM in offsetting demand-related reinforcement; we also comment in section 2.5.4 regarding the need for fully cost-reflective charging methodologies.

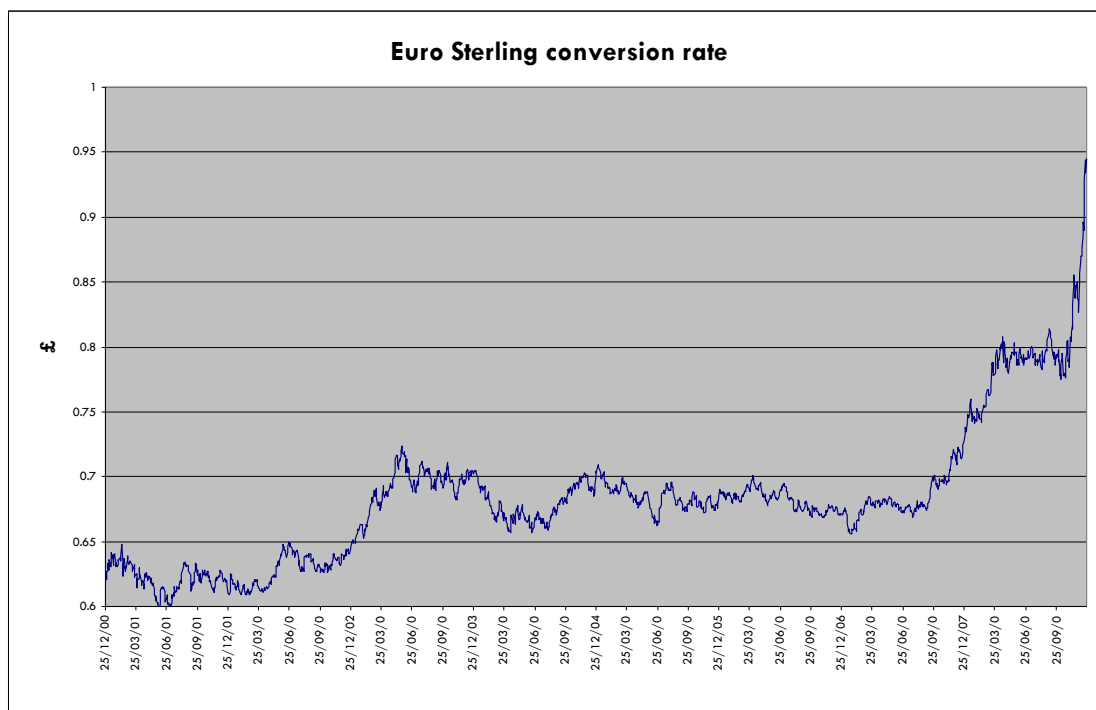
#### **4.8 Managing input price uncertainty (4.49 – 4.55)**

A major challenge for the DNOs in DPCR5 is the retention and recruitment of skilled labour. We believe that the acknowledged skill shortages will increase contract labour costs throughout the period, especially for Senior Authorised Personnel, overhead, jointing and fitting resources. These contractors are likely to attain annual salary increases exceeding the rate of inflation. Whilst we will attempt to mitigate these cost increases through intelligent procurement practices, the impact is likely to increase DNO costs.

Materials prices paid by DNOs (on behalf of customers) largely reflect spot rates ie market reflective prices and a view of future price movements when the contract is negotiated. Ofgem needs to consider relative movements since previous contracts were agreed rather than individual spot rates from submissions. The prices paid by DNOs for materials reflect changes in both commodity and currency fluctuations. Whilst commodity prices have fallen considerably since the HLFBPQ, exchange rates have

deteriorated, which has increased costs. Suppliers of electrical distribution components are typically located in EU member states and therefore subject to the Sterling/Euro exchange rate fluctuations, which represent a 32% direct increase in costs since the start of DPCR4 for the DNO. Transaction costs/risks are included within the price of the materials as manufacturers are aware of the issue and include significant premiums when setting exchange rates.

The graph below illustrates the fluctuations in the exchange rate since 2000. It is notable that since 2003 the exchange rate remained largely stable at around 67p until September 2007 when the price shifted to approximately 79p, an 18% increase. The current rate is trading at near parity, suggesting a cost increase of approximately 40% from the equivalent costs of imported goods in the majority of the first three years of DPCR4.



To understand the impact of the increase in materials costs in DPCR5, we have analysed the top 450 commodities (in terms of total expenditure) procured on secondary network capital programme projects over the past 36 month period. The basket of materials outturned at a cumulative cost of £15.1m. The analysis took into account the quantities and price of the materials procured. This outturn figure was then compared to the cost of the basket had the commodity prices remained constant throughout the period. This showed that the basket of materials had increased by 16% over the three years. RPI for the same period had increased by 13%. Therefore the basket of materials had been subject to a year on year inflation equivalent to 5.12%.

The Grid & Primary materials analysis involved the comparison of price movement of major Grid and Primary commodities such as grid transformers, primary transformers,

33kV switchgear, 11kV primary switchgear, 132kV & 33kV cables and protection equipment. The analysis was based on commodities procured during the financial year ending 2008. The basket of materials outturned at a value of £18.2m. A comparison was made between the cost of the basket of commodities based on prices at the beginning of the period against prices at the end of the period. This analysis showed the basket had increased by 14.3% in the financial year ending 2008. Further details of this analysis are included within our FB PQ submission

Under previous price controls, input inflation may not have had the effect experienced in DPCR4 and likely to be perpetuated in DPCR5. The movement to the use of outputs as a deliverable will increase the importance of Ofgem's approach to managing input price uncertainty. The DNOs' already limited ability to manage input price risk is further constrained as the option to reduce the scope of the investment programme is largely removed.

Whilst it may be appropriate that DNOs are exposed to some of the input price risk to ensure costs are efficiently managed, the nature of the deal proposed at DPCR5 (ie outputs) and the level of uncertainty (and therefore risk) suggests that some form of trigger mechanism should be applied.

We are happy to work with Ofgem to establish an appropriate indexation or cost pass through mechanism for the DPCR5 period. The use of an allowance under the present circumstances would be inappropriate given the potential risk to customers around under- or over-provision of costs. We believe that it may be possible to use the unit cost table in the FB PQ (with a replication of C2 in the annual RRP) to understand the impact of above-RPI inflation. The regulatory treatment to ensure that appropriate behaviours are encouraged and to determine how possible trigger/re-opener mechanisms could be employed needs to be discussed further.

#### **4.9 Equalising incentives (4.56 – 4.62)**

We support the equalisation of capex and opex incentives. Ofgem created a number of issues through the adoption of standardised capitalisation rules in DPCR4 and it is important to recognise that the imbalances in incentives can potentially skew the business cases of individual solutions when non-capex solutions are viable. Since its inception we have supported the RRP project which was designed to help the process of policing the cost boundaries to ensure appropriate comparison could be made between DNOs. It was very disappointing to find that the extremely burdensome regulatory reporting process did not necessarily provide data in a form that easily supported the development of comparative efficiency techniques.

These experiences have shaped our view that, of the three options identified in the policy paper, we should support fixing the proportion of costs which enter the RAV. Expensing business support costs will eliminate some of the incentive effects, but the continuing existence of residual cost boundaries is always going to be a problem and a distraction for Ofgem and DNOs.

Discussions around applicability to IQI should be treated separately as this may distort the dynamics of the incentive properties. Therefore a two stage process is required where the IQI is applied first on the appropriate areas of expenditure; the resulting incentive rate for each DNO should then be applied to all expenditure.

The percentage of expenditure that needs to be expensed to ensure the financeability of the individual DNO can then be determined. It is important to remember that there are core cash requirements for DNOs on a statutory basis which must be financed by the price control settlement. Ofgem must recognise that DNOs have a minimum cash requirement which is likely to vary by DNO group and structure. Failure to meet the cash requirement obviously leads to financeability and price control acceptability issues.

Ofgem should also recognise that equalising cost incentives could reduce the regulatory reporting burden although individual cost categories will still be required for the equivalent DPCR6 FBPQ. It is important that the annual reporting process reduces the pressure upon the DNOs and Ofgem at the price control reviews. The depth and quantity of information requested in the present business plan questionnaires suggest that the present system does not provide the appropriate results.

We raised the issue of incentive equalisation earlier in our response and suggest that this would provide DNOs with the opportunity and incentive to employ the most efficient solutions from a whole life cost perspective.

#### **4.10 IQI (4.63 – 4.68)**

Ofgem recognises the inherent assumption of risk neutrality contained within the IQI mechanism. The consultants' papers on the IQI suggest that companies may need stronger incentives to accept greater risks and, therefore, under the present mechanism would not necessarily reduce bids to the level anticipated by Ofgem. We suggest that this may be resolved by using an asymmetrical mechanism to protect against cost overruns.

Ofgem's modelling and IQI assessments are likely to give some indication as to the appropriateness of the overall scale of company submissions and hence the need to introduce additional scrutiny along the lines outlined to the DNOs in terms of 'Type 2' settlements. This scrutiny could take the form of more detailed scheme analysis and/or reporting on physical activity with a focus on variations from the originally-submitted programmes.

One issue which needs to be resolved is the additional risk placed on the capex programme through the inclusion of output measures. Increasing costs at the efficient bid position through above-RPI cost movements or other unforeseen cost overruns result in the strongest penalties for DNOs at the "efficient bid" level. This reinforces the importance of the sufficiency of above-RPI inflation allowances as the IQI may be utilised by companies as insurance should the allowances appear to be inadequate.

Ofgem has suggested that companies should only be allowed to submit a single bid to ensure that the baseline level of the IQI is not influenced by pre-emptive high bids. Given that the forecast programmes are now based upon outputs and network requirements, we suggest that this issue may not be as prevalent as at DPCR4. There may be some cases where a revised bid may be required if fundamental assumptions used to populate the FBPQ are changed for any reason. The IQI has been presented

by some commentators as a form of menu regulation, and indeed has been developed by Ofwat as such. Unfortunately, the proposed Ofgem process requires DNOs to make a choice from the menu before they have even seen it and then proposes to prevent a change in choice once the menu has been reviewed. This approach may reduce the incentive effect of the IQI scheme.

We welcome the discussions on expanding the IQI to specific opex allowances. The movement towards fixed RAV additions will effectively equalise the efficiency incentive on both opex and capex expenditure and it would seem a logical progression to expand the IQI to the direct components of opex such as tree cutting costs, inspections and maintenance and faults.

It is important that for both Opex and Capex costs that only the appropriate building blocks are included within the mechanism, for example we suggest that opex comparators should exclude business costs. It is appropriate to focus the IQI on the key network costs and many business costs are fixed across DNO groups. We suggest the scope of IQI application in DPCR5 is carefully assessed such that it is applied to areas where the DNO discretion over expenditure levels is greatest, and linkage to outputs most opaque. For example, we suggest that building blocks with clearly defined and transparent activity levels where there is likely to be significant variation in need across DNOs (eg flood prevention programmes, HILP, clearance non-compliances rectification) are excluded from IQI as they lend themselves to specific review and efficiency assessment. Similarly, it may be appropriate to amend IQI mechanics for DPCR5 to reflect not only the inherent riskiness of lower forecasts, but also the degree of output commitment concomitant with those forecasts, ie a low forecast with little output commitment (and hence relatively high DNO discretion) could be treated in the same manner as a higher forecast with more mature output commitments.

If the IQI mechanism is applied to opex on a similar basis to capex, it is important that comparative efficiency be used in conjunction with activity volume projections in determining allowances before being entered into the IQI mechanism.

Ofgem suggest that the introduction of the various mechanisms for dealing with uncertainty (input price indexation and volume drivers) will remove some of the risk out of the IQI mechanism, which may allow for sharper incentives around the IQI bid. We agree with this in principle but the issue clearly requires significant detailed design work on the appropriate regulatory tools.

#### **4.11 Output measures (4.69 – 4.77)**

The nature of the service that DNOs provide and investment they undertake means that it can be difficult to ascertain appropriate output measures that apply to measure the effect of investment over the short-term. In particular, investment undertaken to ensure ongoing and enduring network adequacy and performance are not measurable in terms of immediate customer effect and so concepts of risk are used to indicate medium and long-term stewardship trends.

There is no agreed approach to this, and DNOs have individual ways of addressing the same aspects, endeavouring to manage the issues on a basis appropriate for their

businesses. It is therefore likely that Ofgem will receive varied responses in the FBPQ of differing levels of maturity and application.

Our work through ENA Working Groups and elsewhere reinforces how hard it is to define a common framework for output measures, however it has become clear over the last couple of years that a number of preferred approaches are emerging, for example the use of health indices to indicate the condition of individual assets and the overall asset base. In addition, completion of the FBPQ tables will reveal significant information regarding the expected outcomes of the proposed investment due to the nature and design of the tables which has developed from the RRP process with significant DNO input.

DNOs should therefore be in a position to define some initial output measures with a broad indication of the effects of planned investment on them.

In assessing the 'sufficiency' of proposed outputs in FBPQ submissions, we consider that this should be split into two:

- Assessing the appropriateness of the proposed measure itself.
- Assessing the appropriateness of the framework, outcome or target that a DNO chooses to wrap around the chosen output measure.

For example, an output measure could be entirely appropriate and well-defined but the DNO's specific proposal against it in terms of DPCR5 projected performance is inappropriate.

It will not be sufficient for DNOs to submit a plethora of ill-thought out measures which have minimal influence on the outcome which it is sought to observe. Ofgem will thus need to apply scrutiny to the possible characteristics of proposals that would indicate the appropriateness or otherwise of including such metrics in some form of output contract. These could possibly be weighted, scored or otherwise assessed. Such factors could include;

- Measurability
  - Widely acknowledged metric? Industry-standard definitions?
  - Existing audit regime? Internal or external to the company?
  - Currently reported? Internal or external? Current regulatory requirement?
  - Individual measures or composites?
  - Interplay between measures?
  - Effectiveness of measure (as an indicator), ie how well does it represent that which we're trying to measure
  - Average measures or measure of spread/extremes
- Replicability
  - Any changes to definitions over time?
  - Comparable across companies (or if not, readily normalised?)?
- Controllability
  - Is the DNO in complete control of outcome risk, or managing either probability or consequences?

- Is the DNO managing volume, unit cost or both risks?
- Relevance to outcome
  - Not likely to lead to 'wrong' or undesired behaviour?
  - Low risk of unintended consequences
- Predictive Capacity
  - How well does the measure correlate with historically-predicted outcomes?

There may also be a case to reward companies who are proposing more advanced metrics but taking some outcome risk due to their relatively early state of development. For example:

- Level proposed compared to level committed to by others? (DNO A committing to 100 units of replacement, whereas DNO B commits to a defined fault rate?)
- Level proposed compared to that theoretically possible

As an example, counting switchgear replacements is very measurable, replicable and controllable but not particularly relevant to the ultimate outcome being sought (it is a Tier 3 output seeking to achieve a Tier 1 outcome, ie manage network risk.)

Ofgem's modelling and IQI assessments are likely to give some indication as to the appropriateness of the overall scale of company submissions and hence the need to introduce additional scrutiny along the lines outlined to the DNOs in terms of 'Type 2' settlements. This scrutiny could take the form of more detailed scheme analysis and/or reporting on physical activity with a focus on variations from the originally-submitted programmes.

#### **4.12 Cost assessment methodology (4.78)**

We agree with Ofgem's intention to place more emphasis on individual DNO 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 RRP 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 important to recognise that the RRP has been developed for different purposes – it will be important going forward to develop cost reporting to provide the right data for comparative efficiency, rather than develop comparative efficiency approaches that work with the data available. 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.

#### **4.13 Comparative efficiency analysis (4.79 - 4.82 & Appendix 8)**

We recognise the progress that Ofgem have made since their Initial Consultation in developing comparative efficiency approaches. We agree that it is sensible to continue to refine these processes for publication in May 2009 rather than to attempt to publish undeveloped models in this document. We agree that the outline thought-process set out in appendix 8 is logical and have structured our response against those steps.

We look forward to working with Ofgem on developing an appropriate approach to comparative efficiency assessment and allowance setting.

Ofgem needs to be careful when making international comparisons for the purposes of efficiency. The cost data needs to be captured on consistent basis to UK regulatory definitions, which are very different to international accounting standards. Across different countries there are different regulatory structures and different definitions of distribution companies. International comparators may however give useful indications as to whether the recent trend in cost changes is global or UK specific.

Ofgem must include all margins in all models when comparing performance against DNOs. Excluding legitimate efficiently incurred costs will distort the results for all companies and set inappropriate cost allowances.

##### **4.13.1 Gathering appropriate cost and other data**

We recognise that Ofgem has made significant progress through the RRP development in obtaining appropriate cost data for all DNOs on a broadly consistent basis. However, there are still outstanding data consistency issues, largely as a result of residual boundary issues, that must be recognised in modelling.

During the FBPQ process to date Ofgem have recognised that an RRP designed to ensure consistency with DPCR4 rules has not captured sufficient data to assess comparative efficiency. The fact that DNOs are being asked to report historical costs on a different basis in the FBPQ will introduce a further level of uncertainty into data used for comparative analysis as costs reported will not have been subject to the level

of scrutiny associated with annual RRP cost reporting processes. Going forward it will be important to develop cost reporting to provide the right data for comparative efficiency, rather than develop comparative efficiency approaches that work with the data available.

#### **4.13.2 Determining which costs should be assessed by benchmarking**

We believe that it is not sensible to assess required expenditure via comparative methodologies where:

- DNOs have no control over costs eg business rates, licence fee
- Costs are only incurred by some DNOs and not others eg island generation
- Where DNOs incur expenditure at different rates for legitimate reasons that cannot be factored into models eg wayleave costs, pensions, lane rentals

As such we agree with most of Ofgem's suggested approach to costs to be excluded from comparative analysis.

We strongly advocate excluding pension costs from comparative modelling; pension costs are incurred at different rates by different DNOs for legitimate reasons (eg regional longevity differences, historical contribution rates, different valuation dates) with different drivers and should be subject to separate analysis and allowances.

We support Ofgem's view that insufficient data is available on the long-term costs and drivers of IT, telecoms and property costs to assess these via comparative analysis. We agree with Ofgem's proposal to appoint consultants to review required levels of future expenditure.

We believe that all atypical costs must be removed from analysis. If Ofgem doubt the consistency in which atypical costs have been reported by DNOs it is much more appropriate to review these costs with DNOs and if necessary, reclassify inconsistent data than to distort modelling by inclusion of atypical events.

It is of fundamental importance, however, that DNOs receive appropriate allowances to fund those activities that are excluded from analysis. Non-comparability of costs must not be considered evidence of inappropriateness.

In reviewing storm costs incurred as part of setting allowances for future severe weather events Ofgem must take into account which DNOs have experienced such events and the nature of those events. Allowances must reflect the likely frequency of severe weather events, including the likelihood of events of greater magnitude than experienced during the current period and the possible impact of climate change on frequency of severe weather events.

#### **4.13.3 Adjusting base data to remove inconsistencies**

We agree that it is appropriate to adjust modelled costs to ensure that comparisons are made on equivalent basis. Before making adjustments Ofgem must have evidence of genuine distortion of costs and a robust methodology for making adjustments. We have severe reservations about some of the adjustment proposed by Ofgem, both their

appropriateness and the availability of appropriate methodologies to make adjustments.

We cannot agree that the DPCR4 rule of assuming that margins incurred by related parties with more than 75% turnover outside the group are efficient (and vice versa) can ever be correct in all cases. Excluding efficient margins from models may create false frontiers and result in DNOs being given insufficient allowances to run their operations. Inclusion of some, but not all, margins may distort modelling results and provide inappropriate allowances to some DNOs. We believe that it would be more appropriate to include all related party margins in models; with such an approach the results of modelling with then reveal the true relative efficiency of related party costs and margins.

As mentioned previously, we believe that the legitimate differences in pension contribution rates between DNOs will distort modelling results disproportionately if pension costs are included within modelled costs. The normalisation of pension rates within models, whilst superficially attractive, will simply create problems of determining the appropriate level of modelled costs to be removed to avoid double counting with pension allowances. We contend that the risks to customers of double counting allowances or the risks to DNOs of removing too much from allowances are too great to justify such an approach.

We do not accept that material regional variations in labour and contractor costs exist outside of the immediate Greater London area and as a result strongly contend that it is inappropriate to adjust the costs of all DNOs.

Ofgem needs to exercise caution if it considers that some form of adjustment is required to reflect regional cost differentials. Several DNO activities do not need to be located within the footprint of the network. Companies are able to locate administrative and support staff in lower cost areas. Direct labour needs to be located in reasonable proximity to the network, but most other roles could be undertaken in any area of the UK. As an example of this issue, whilst many companies have headquarters in London and hence high headquarters salaries, some do not. It may be essential and efficient that these activities and staff are located in the nation's capital, reducing travel costs and providing the opportunity to address specific issues, but the efficiency of the decision on their location can only be determined if these costs are included within an overall comparative efficiency assessment and are not adjusted. We are also concerned by the reliance on data provided by one DNO group relating to regional cost adjustments. It is important that Ofgem demonstrates that any models or data utilised to produce cost allowances have been robustly challenged and validated.

We would suggest that, excluding the centre of London, there is no evidence of regional contractor markets. We also note that in GDPCR, PB Power found no evidence for variations outside immediate London weighting.

Many of the activities undertaken by DNOs do not need to be undertaken within their operating area, for example control rooms and call centres may be located out of area – indeed many DNOs within multiple ownership groups share these resources in one location which, by definition, must be outside the operational area of at least one DNO. To make adjustments to all DNOs' costs profiles for activities that need not be

undertaken within operational areas would simply provide an unjustified benefit to companies in the South East and wrongly penalise companies in other areas.

We accept that DNOs operating within the Greater London area will need to provide some degree of compensation to those directly employed members of staff who work within the capital. We do not believe that any readily available data set exists to make detailed adjustments to modelled costs without introducing significant errors. Instead, we recommend that Ofgem undertake a survey of companies operating across the UK to determine the level of compensation required for London based employees in industries subject to competitive pressures and provide DNOs based within the South East with additional allowances based on this external benchmark for an efficient staffing level for those activities that can only be undertaken within the operating area.

It is essential that Ofgem recognise the legitimate differences in reported cost structures that can arise - as a result of cost reporting rules - depending on whether DNOs insource or outsource activities. The cost reporting rules will result in different efficient levels of direct and indirect expenditure dependent on operating structures. We are pleased that Ofgem recognise this, but urge Ofgem to be aware of the exacerbating effect this will have on "cherry picking" that inevitably exists in bottom up modelling. It will prove very difficult to normalise for this within any disaggregated cost model that analyses separate blocks of costs. We believe that the most sensible test is to undertake top-down modelling to test for the extent of cherry picking – for all DNOs – and to adjust allowances accordingly.

We agree that the variable spend profile of non-operational capex investments makes it inappropriate to include un-normalised costs within models. We do not believe that sufficient data is available to normalise IT and telecoms and property non-operational capex spend as such investments are made over much longer periods than the four available years of DPCR4 data can represent and we support a review of these costs by specially appointed consultants. We suggest that it would be appropriate to use the average of the four years' data available for vehicles, plant & machinery and small tools and equipment non-operational capex expenditure within comparative models. We also agree that it is sensible to combine vehicle non-operational capex with vehicle & transport indirects costs for analysis and to apportion plant & machinery and small tools & equipment over relevant direct activities; this best normalises for the alternative ownership strategies available to DNOs in these expenditure areas.

We disagree with the use of statutory depreciation as an approach to normalising non-operational capex expenditure. Our analysis that led us to this conclusion is included in appendix 1.

We believe that other expenditure areas of variable annual expenditure rates, such as fault and maintenance expenditure on EHV and 132kV assets should be assessed on an average of several years or unit cost basis.

We believe that Ofgem should only adjust for accruals that turn out to be incorrectly posted and were retrospectively adjusted within the DNO's accounts. Normal trading accruals will not vary materially from year to year; we believe it is more appropriate

to include these within comparative models as they have been subjected to audit and challenge as part of annual reporting processes.

There is a risk that the size of normalisation adjustments made to core data may prove almost as large as the modelled costs themselves. Ofgem must consider the impact that large adjustments can make of the robustness of model results; making inappropriate adjustments or wrongly calculated adjustments will introduce a level of error that may undermine the validity of modelling results.

#### **4.13.4 Determining cost groupings**

We agree that the majority of cost groupings suggested by Ofgem seem sensible. The one exception to this is the inclusion of network policy costs within capex driven activities. The majority of network policy costs are not capex driven; they are largely fixed costs that would be more logically grouped with finance & regulation and CEO.

#### **4.13.5 Determining associated drivers**

It is extremely important that cost modelling approaches recognise the real drivers of costs. Models that ignore drivers of cost and changes in drivers will incorrectly influence allowance calculations. Limiting models to prime driver and/ or incorrect selection of measures of drivers may result in part of perceived inefficiency actually being from missing drivers. This must be recognised and adjusted for in allowance setting.

We agree that most suggested drivers of blocks of cost seem sensible primary drivers. We are concerned, however, that Ofgem do not have and cannot determine within required timescales accurate measures of many of the suggested drivers. For example:

- Asset count/ length data are sometimes reported inconsistently by DNOs, eg pressure assisted cables
- “Assets added” is inappropriate as a measure of capex undertaken. For example, refurbishment volumes are not included but are important capex activities. Excluding refurbishment volumes from any measure of capex undertaken will penalise DNOs who seek lowest cost solutions that often include refurbishment activities.
- Analysis of fault unit costs gives very wide ranges of results which suggest that different DNOs employ different definitions in RRP and IIS reporting.

Finance & regulation, CEO and network policy costs have large elements of fixed costs that can be shared between companies within one ownership group. We believe that analysis of these activities should be evaluated on an ownership group basis, with allowances set per ownership group, not per licensee.

#### **4.13.6 Carrying out appropriate statistical testing or other analysis**

We agree with Ofgem’s proposed approach of using alternative modelling approaches including different functional forms, and use of DEA and SFA, etc. The

potential errors associated with cost exclusions, normalisation adjustments, choice of relevant drivers, measurement of drivers, selection of an appropriate functional form of the model and legitimate differences that can never be fully normalised for in bottom-up models (such as insourcing and outsourcing) mean that appropriate “sense checks” are essential.

We agree that it is sensible to use standard statistical tests to test the validity of results. It is essential, however, that Ofgem are not tempted to chase strong statistical results at the expense of logical modelling approach. It is important that Ofgem recognise that the existence of a seemingly strong statistical test result will not always be indicative of a sensible model; it can indicate co-variance of drivers, coincidence of DNO approach due to allowance setting in prior reviews or indeed be a random result. Conversely poor results can be an indication of very varying levels of DNO efficiency in an appropriate model.

#### **4.13.7 Establishing benchmark – especially taking error into account**

In establishing a benchmark to be used for allowance setting Ofgem must make adjustments for:

- The “cherry picking” effect of choosing separate benchmarks for each cost grouping
- The exacerbation of this cherry picking effect as a result of insourcing and outsourcing strategies influencing the modelled efficiency in each cost block.
- The level of customer service provided by each DNO and the impact this has on value for customers.
- The extent to which cost groupings include fixed costs and whether these can be shared by DNOs within ownership groups.
- The extent to which apparent “inefficiencies” may be a result of the limitations of modelling approach

The extent of cherry picking and insourcing and outsourcing may be tested for via the use of a range of top-down models that model more activities. These top-down models can be used as a basis to adjust allowances suggested via bottom up analysis. As part of this top-down modelling 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.

Where the rankings of DNOs differ materially between bottom-up and top-down models or between different bottom-up or top-down models Ofgem will need to look carefully at the modelling approach and be absolutely confident that such results do not indicate fundamental modelling errors.

Top-down modelling, however, will not adjust for apparent “inefficiencies” that result from the limitations of modelling approach. If results of different top-down models prove inconsistent it would be sensible to set allowances based on 3<sup>rd</sup> decile or even average costs or via “best of” or “average of” several modelling approaches.

For activities that contain significant levels of fixed costs it is important that in setting allowances no implicit assumption is made that material efficiencies can be made from these fixed costs without any supporting evidence. Similarly, where evidence suggests that fixed costs can be shared between DNOs in the same ownership group allowance setting must reflect this and provide extra fixed cost allowance for DNOs in single ownership groups.

We understand Ofgem's desire to compare UK costs to international benchmarks but urge care in their use. Even if it is possible to find international data for companies with similar responsibilities, ownership structures and regulatory approaches, the level of development of regulatory cost definitions via the RRP is such that we doubt that truly equivalent comparator data is likely to be available.

#### **4.13.8 Forecasting the impact of changes on costs**

We are pleased that Ofgem has recognised that indirect cost allowances must be increased to reflect the increasing level of direct activities that they support. As such, comparative efficiency must be used in conjunction with cost projections in determining allowances. This adjustment must also take into account agreed network outputs and the relative customer service provided by DNOs.

Allowances must also be adjusted for the anticipated impact of input price changes relative to RPI.

#### **4.13.9 Applying catch up, ongoing efficiencies and adjustments**

We recommend that, as part of their top-down tests and comparator models, Ofgem assesses their level of confidence in the results of their modelling approach. If, for example, they find that different models project very different expenditure requirements for some DNOs they should recognise the uncertainty in the results of their modelling and allow DNOs an appropriate period of time – we suggest 10 years – to catch up to modelled cost levels.

The fact that the majority of DNOs are overspending their DPCR4 opex allowances illustrates the extent to which there is very little scope remaining to make further efficiencies. Ofgem must recognise that their exclusion of some related-party margins and their adjustment for income associated with sale of assets and excluded service revenues from their comparison of costs to allowances mean that many DNOs' performance is in fact even worse; indeed in our own case the underlying position is of overspending DPCR4 allowances. We do not believe Ofgem should apply further efficiency adjustments to modelled costs.

#### **4.13.10 Carrying out expert review or other bottom-up analysis**

As mentioned previously, we agree that consultants should review IT and telecoms and property costs. Ofgem does not have sufficient data to allow any sensible assessment via comparative modelling.

We also agree that apprentice costs should be modelled separately. Different DNOs have invested very different levels of expenditure on apprentices to date; this difference is sufficiently material as to distort modelling approaches. Separate

analysis of anticipated expenditure will also allow appropriate attention to be placed on the very real problem of imminent skills shortages as a result of increasing capex programmes and ageing work-forces.

#### **4.14 Assessment of Network Investment Requirements (4.83 – 4.84)**

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. We agree with Ofgem's suggested approach to separate projected volumes from unit cost. These represent two different aspects of the construction of a capital programme. Decisions on volumes need to be determined with regard to the future network requirements. Ofgem need to be aware of the impact of differing operational structures on the costs reported within investment programme (eg the varying approaches to outsourcing applied within the DNOs).

We welcome the inclusion of the unit cost survey for DPCR5 and its aspiration to understand better the differing definitions and scopes of works across the DNOs. This exercise is however fraught with comparability issues, particularly as reported costs will be on a regulatory basis and hence the product of a conversion process. Ofgem must recognise that apparent efficiency may simply be a function of definitional or allocation differences, which will exacerbate the dangers of producing unattainable benchmarks by cherry-picking of frontier rates in each category. There must also be some benefit for frontier companies to encourage further efficiencies.

##### **4.14.1 Asset replacement**

We have moved away from the use of age-based modelling and developed a condition based approach for our investment plans based on Condition Based Risk Management (CBRM).

We would welcome the opportunity to demonstrate how this approach is used to forecast future asset replacement volumes and the likely impact on future fault rates and asset health.

##### **4.14.2 Load-related investment**

We see a volume driver for new connections reinforcement as possible but we would recommend at least disaggregation of the connections volumes across voltage levels and separate drivers at each level to reflect the differing costs associated with reinforcement across the levels.

In respect of general reinforcement we agree with the proposal to introduce bespoke demand (MVA) drivers for identifiable areas of the network, supplemented by a trigger process for high materiality projects (in the same way that, for example, NGET's 'revenue drivers' are tailored to zonal conditions). We are interested to understand the exact operation of the proposed capex driver and would stress that the operation should recognise the significant lead times associated with reinforcement projects. Specifically, the trigger mechanism should take cognisance of the 18-24 month lead time associated with large grid and primary projects. We would caution against adoption of simplistic model outputs as reinforcement drivers and measures of

network risk. It is our experience that modelling techniques should be used as a 'stress' test of the network and identified issues must be confirmed by a detailed study of the 'stressed' area.

## Appendix 1 – Comparative Modelling of Non-Op Capex

We see 5 broad options for modelling the efficiency of historical non-operational capex spend and for determining required future spend:

1. Use one year's non-op capex numbers from either RRP T2.2 or T2.4
2. Use averaged non-op capex numbers from T2.2
3. Use averaged non-op capex numbers by expenditure category from T2.4
4. Use statutory depreciation from T2.2
5. Carry detailed review of expenditure, possibly utilising consultants with expertise in each expenditure area

There are pros and cons associated with each of these approaches, which we outline below.

<b>1. Use one year's non-op capex numbers from T2.2 or T2.4</b>	
<b>Pros</b>	<b>Cons</b>
	<ul style="list-style-type: none"> <li>• One year's data is unlikely to represent DNO investment profile due to "lumpiness" of this type of investment</li> </ul>

<b>2. Use averaged non-op capex numbers from T2.2</b>	
<b>Pros</b>	<b>Cons</b>
<ul style="list-style-type: none"> <li>• Allows adjustments to be made for eg pension costs</li> <li>• 3+ years data available to provide average (possibly 5 if include 04/05 and 08/09). Probably sufficient for relatively short lived assets eg vehicles, tools &amp; equipment</li> </ul>	<ul style="list-style-type: none"> <li>• Does not allow split by expenditure type eg vehicles, IT</li> <li>• Unlikely to have sufficient years of data available to compare expenditure on longer lived assets such as property and IT – analysis will be distorted by "lumpiness" of investments by DNOs</li> <li>• Levels of investment may be distorted by different DNOs' strategies on purchasing or leasing assets</li> <li>• The sometimes unique nature of drivers of non-operational capex (eg technical obsolescence in IT, urban re-development requiring properties to be divested) mean that historical spend is often not a good indicator of required future spend, especially for IT and property costs</li> </ul>

<b>3. Use averaged non-op capex numbers by expenditure category from T2.4</b>	
<b>Pros</b>	<b>Cons</b>
<ul style="list-style-type: none"> <li>• Allows split between expenditure type against regulatory definitions</li> <li>• 3+ years data available to provide average (possibly 5 if include 04/05 and 08/09). Probably sufficient for relatively short lived assets eg vehicles, tools &amp; equipment</li> </ul>	<ul style="list-style-type: none"> <li>• Unlikely to have sufficient years of data available to compare expenditure on longer lived assets such as property and IT – analysis will be distorted by “lumpiness” of investments by DNOs</li> <li>• Do not have sufficient information to apply cost adjustments eg pensions removal</li> <li>• Levels of investment may be distorted by different DNOs’ strategies on purchasing or leasing assets</li> <li>• The sometimes unique nature of drivers of non-operational capex (eg technical obsolescence in IT, urban re-development requiring properties to be divested) mean that historical spend is often not a good indicator of required future spend, especially for IT and property costs</li> </ul>

<b>4. Use statutory depreciation from T2.2</b>	
<b>Pros</b>	<b>Cons</b>
<ul style="list-style-type: none"> <li>• Allows more years to be taken into account than averaging costs from 2.2 or 2.4</li> </ul>	<ul style="list-style-type: none"> <li>• Statutory depreciation will include elements of eg pension costs, margins, etc that cannot be adjusted</li> <li>• Statutory capitalisation rules are different to regulatory rules, eg costs depreciated are likely to include some indirect costs</li> <li>• Different DNOs will use different asset lives and different depreciation profiles which may distort analysis</li> <li>• Depreciation lives may not reflect actual asset lives</li> <li>• Depreciation is based on historic cost, so contains an unknown mixture of price-bases</li> <li>• Some DNOs report depreciation against individual asset categories whereas other book it against non-operational capex, making comparison difficult</li> <li>• Levels of investment may be distorted</li> </ul>

	<p>dependent on DNO's strategy on purchasing or leasing assets</p> <ul style="list-style-type: none"> <li>• The sometimes unique nature of drivers of non-operational capex (eg technical obsolescence in IT, urban re-development requiring properties to be divested) mean that historical spend is often not a good indicator of required future spend, especially for IT and property costs</li> </ul>
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**5. Carry detailed review of expenditure, possibly utilising consultants with expertise in each expenditure area**

Pros	Cons
<ul style="list-style-type: none"> <li>• Allows all assets, whether purchased or leased, no matter when purchased and whether fully depreciated, to be considered</li> <li>• Allows differences in DNOs timing of investment to be factored into analysis</li> <li>• Allows details of drivers of future expenditure, and how they vary by DNO, to be understood</li> <li>• Allows advantages of investment that are realised elsewhere to be taken into account eg more robust investment requirements as a result of investment in asset data and CBRM, to be considered in determining the appropriateness of investment, spend to save projects</li> </ul>	<ul style="list-style-type: none"> <li>• Removes direct link from modelling of RRP costs</li> <li>• A more time consuming approach requiring detailed review of DNO expenditure plans</li> </ul>

This analysis shows that there is no one obviously correct answer. We are not convinced that using statutory depreciation provides a sufficiently robust approach to modelling non-operational capex costs. In particular, our concern that data may not be consistently determined between DNOs undermines the principles enshrined within the RRP process that all DNOs report costs on a consistent basis.

A review of trends in non-operational capex from DNOs' table 2.4 submissions shows that some categories of non-operational capex show much more variable levels and frequency of expenditure than others. A range of expenditure patterns is observed from "small tools and equipment" (all DNOs make small levels of expenditure in every year of DPCR4) to "property" (widely varying levels and frequency of expenditure). This suggests to us that different approaches to assessing appropriateness of expenditure may be appropriate to different categories of expenditure.

On balance, we recommend:

- For shorter lived assets, such as vehicles and small tools and equipment, an average of all DPCR4 costs should be taken and modelled together with

associated indirect costs. We recommend using the split of costs available within T2.4, possibly with a supplementary data request asking DNOs to identify pension costs included within reported costs.

For longer lived assets, such as IT & telecoms and property, we recommend commissioning consultants to review expenditure across both non-operational capex and indirect expenditure and to make recommendations about future expenditure requirements.

## **5 Financial Issues**

### **5.1 Chapter Summary**

DPCR5 is being conducted at the height of the “worst economic crisis for decades” and against the backdrop of a global recession. The DPCR5 settlement will need to reflect the prevailing economic conditions, recognising that the level of uncertainty and risk borne by customers, investors and stakeholders has increased significantly. Ofgem’s first challenge in DPCR5 is to promote confidence and reassure customers and investors.

The macroeconomic conditions exhibited in the recent months have raised a number of issues for the regulated entities. The concern for both regulators and the regulated companies is how to create a fair and equitable price control for all parties when the traditional datasets are likely to be distorted. One concern is the implicit assumption that conditions return to normal at some point in the future.

Government and other stakeholders want us to continue to invest in our vital infrastructure, play a full part in facilitating the move to a low carbon economy and ensure that we have long-term security of supply. Therefore ENW, like many other DNOs, must make a significant increase in investment in DPCR5. Consequently, we need to be confident that expenditure will be recoverable and that finance is available and affordable. There is a strong message within the Policy Paper that DNOs will be required to change, to innovate and to take on more risk. Innovation is certainly required if we are to meet the twin challenges, of dealing with the economic crisis and moving towards a low carbon economy, simultaneously. However, customers should not be expected to pay too heavy a price for these developments because the financial markets lose confidence in the regulatory regime. Ofgem must find the right balance between making the necessary changes to address the immediate issues caused by the economic circumstances and, where possible, continuing the refinement of the price control mechanisms and the wider regulatory framework.

#### **5.1.1 Return on Regulatory Equity**

In its review of the DPCR4 settlement, Ofgem has developed the Return on Regulatory Equity (RORE) mechanism to assess the effectiveness of the incentive regime on the DNOs. In terms of pure principles, this appears to be a sensible point to start considering how DPCR5 should be shaped. The methodology employed to calculate the returns contains assumptions which produce highly theoretical results. We suggest that this work may provide misleading messages on the actual levels of returns experienced by a DNO. A more traditional approach will reveal the actual return on equity for each company and must be incorporated in any assessment. Going forward we agree that RORE can be used to calibrate individual mechanisms, but believe that placing any overall cap on total RORE would be counter-productive and raise perception of regulatory risk.

### **5.1.2 Cost of capital**

It is important that Ofgem allow a sufficient cost of capital to encourage and retain investors. DNOs are likely to require large scale capital programmes in DPCR5 and therefore require access to capital markets on reasonable terms. Ofgem's commitment to retaining the methodology for calculating the cost of debt and equity and maintaining a post-tax approach eliminates a degree of uncertainty from the price control process and this is welcomed.

### **5.1.3 Cost of equity**

We suggest that the current increase in the cost of investment grade debt (and the future cost of investment grade debt) must lead to an increase in the required return on equity, since equity holders are the residual claimants after bondholders.

### **5.1.4 Cost of debt**

To meet the needs of our customers and other key stakeholders Ofgem need to develop a regulatory framework that acknowledges the full extent of the investment programme we must undertake. The DPCR5 price control must recognise that the DNOs require significant levels of financing from the investment communities to deliver the proposed outputs. Whilst the utilities sector has been viewed as a reasonably low risk investment in the past and attracted comparatively low interest rates, the current circumstances are likely to result in materially higher financing costs with more restrictive debt covenants for a number of years. The DPCR5 price control must encourage equity investors by giving the reassurance that should the costs of new debt be greater than assumed in the price control settlement, a mechanism exists for Ofgem to fund these costs, where companies have acted appropriately. This approach can also protect customers from the risk of over compensating DNOs, should debt costs fall more quickly than expected.

It is widely recognised that the traditional RFR calculation methodology using the index linked gilt market is working inefficiently. NERA suggested that an alternative approach was available to calculate a RFR based upon swap rates. Ofgem has not discussed its views on this matter and it may be useful to understand the Ofgem position before the initial proposals.

### **5.1.5 Gearing**

The gearing assumption at DPCR4 was based upon the efficient financing structure of a notional DNO. We recommend that the DPCR5 rate should not vary materially from the DPCR4 assumption.

### **5.1.6 Depreciation**

We suggest that Ofgem should retain the current 20 year asset life for DPCR5. If Ofgem are minded to change the asset life, it requires careful consideration and should only be addressed during the RPI-X@20 review.

### **5.1.7 Financial modelling**

The DPCR4 financeability tests were set “by calculating and assessing certain financial ratios that are used by credit rating agencies and others in the financial community to assess the financial strength of a company”. It is important that Ofgem continue to reflect the view of financeability held by the various financial institutions including PMICR and set ratios consistent with an A- credit rating.

### **5.1.8 Treatment of taxation**

Ofgem have committed to maintaining the current approach to setting tax cost allowances. We believe that this incentivises the DNOs to operate efficiently. Ofgem’s proposal to include a symmetric trigger mechanism to protect customers and DNOs against potential movements in taxation rates is appropriate. We also agree with the principles of a tax gearing claw back adjustment.

### **5.1.9 Pensions**

We welcome the Ofgem statement that the pension principles are appropriate and that further work will focus upon the application of the principles. We would like to see consistency of pensions treatment agreed for DPCR5 within a longer term acceptance of the established pension principles. We believe that the funding must be provided in line with the actuarial recommendation as accepted by the trustees. The Pension Regulator has set guidelines for deficit repayment with a trigger point for further scrutiny of 10 years. We believe there are strong arguments for a change in the treatment of deficit repair costs, while maintaining the pass through principle. We believe the most appropriate regulatory treatment of deficit repairs would be to fund these costs as opex, matching the DNO’s cash flows.

Valuations used for funding must be based on actuarial valuations as this matches the cash deficit funding. The option of a re-opener once the next tri-annual valuation is complete would seem the preferred option.

## **5.2 Answers to Ofgem’s Specific Questions**

### **Question 1: Have your views on the appropriate methodology for setting the cost of capital or on indexing the cost of debt changed as a result of the current turmoil in the capital markets**

Our view of the appropriateness of debt indexation has developed since the initial consultation response. This has been driven by the depth of the liquidity issues experienced in the markets and the resulting impact on debt costs. A detailed analysis and discussion of this issue is contained within section 5.5.2.

### **Question 2: What is the appropriate timing of actuarial valuations for setting ex ante pension allowances?**

Valuations used for funding must be based on actuarial valuations as this matches the cash deficit funding. Use of ‘best estimates’ is not appropriate as a basis of funding.

Additional actuarial valuations will be expensive and timely, adding little value as cash payments will only be altered after the next full triennial valuation has been completed. The option of a re-opener once the next triennial valuation is complete would seem the preferred option. See also section 5.9.

### **5.3 Economic Climate and Implications for DPCR5 (5.2 – 5.5)**

It is important for Ofgem to recognise that the DNOs require significant levels of financing from the investment communities to deliver enhanced outputs. Whilst the utilities sector has been viewed as a reasonably low risk investment in the past and attracted comparatively low interest rates, the current mismatch between debt availability and the growing capex requirements of various utilities, whilst unlikely to constrain programmes, will result in higher financing costs and tighter covenants. The current experience of numerous utilities has illustrated the marked widening of utility bond spread (approximately 150 basis points). This has significant implications for present and future financing of the regulated business and the cost divergence between targeting an A- or BBB investment grade credit rating

The macroeconomic conditions exhibited in the recent months have raised a number of issues for the regulated entities in delivering the current price control settlement. The concern for both regulators and the regulated companies is how to create a fair and equitable price control for all parties when the traditional datasets are likely to be distorted. The comforting factor is that the DNOs are long term in nature, with a historically stable risk profile and the core business should attract returns which should not deviate materially from previous settlements, though they may appear relatively low in good times and relatively high in bad times. We note the recent work by the Competition Commission (CC) on the Stansted price control review that illustrates a number of the issues with regard to the development of a price control under high levels of uncertainty. Our key concern is with the implicit assumption that conditions will return to normal at some point in the future. Arguably, the recent conditions have been driven by an inefficient pricing of debt (and therefore risk), which suggests a correction to the costs previously described as “normal”. The settlement for DPCR5 needs to incorporate mechanisms to provide some protection for DNOs and customers.

One of the tools proposed by the Competition Commission in its Stansted proposals was the adoption of a target investment grade credit rating of A-, noting that companies with BBB category ratings have been able to raise new debt finance if they are prepared to meet lenders’ demands on price, but must plan more carefully the timing of new issuance and will typically need to access both the bond and bank markets. By contrast, companies with A category ratings appeared to have been less affected by the credit crunch and are better placed to raise new capital at a reasonable cost. The CC also suggested that it needed to target a comfortable investment grade credit rating (IGCR), after allowing for absorption of downside risk. This may be one way of securing long term lower rate debt (which is funded by current and future customers) whilst providing increased short term revenues to produce higher credit ratings. The alternative is targeting a lower IGCR with associated higher cost debt, which on a whole life cost basis may be more expensive for customers.

## **5.4 Return on Regulatory Equity (Chapter 1, 1.20 – 1.35)**

In its review of the DPCR4 settlement, Ofgem has developed the Return on Regulatory Equity (RORE) mechanism to measure the effectiveness of the incentive regime on the DNOs. We suggest that this work may portray misleading messages for investors, consumers, stakeholders and the Government on the levels of returns achieved by DNOs.

This work is highly sensitive. The timescales set out in the 6<sup>th</sup> November “Update” paper and delayed calculations provided on the 21<sup>st</sup> December have limited the ability of the DNOs to provide detailed and reasoned challenge to the calculations. The variance between the circulated values and those published in the policy paper suggests that the timescales have been insufficient for a valid challenge process. Conclusions based upon this work should be considered with this issue in mind.

### **5.4.1 Principles**

Ofgem has adopted the RORE mechanism to review the DNOs DPCR4 performance and how this relates to customer benefits. In terms of pure principles, this appears to be a sensible point to start considering how DPCR5 should be shaped. We see merit in using a measure such as the RORE to demonstrate how Ofgem allow efficiently managed companies to finance their functions in DPCR5.

Ofgem suggest that a more holistic view of company returns is required and return on equity is a more appropriate measure rather than return on RAV. It is important to recognise the returns available throughout the price control package but the focus on the WACC is understandable and expected given that allowed returns represent one of the largest elements of allowed revenue for the regulated DNOs.

### **5.4.2 Methodology**

The policy paper suggests that Ofgem “only expect the very highest performing companies (in terms of customer service) to be earning equity returns in excess of those generally available to shareholders in non-regulated businesses”. The approach adopted by Ofgem to calculate RORE will not allow this comparison at present. A total actual returns calculation of return on equity (as we suggested throughout the consultation process) would allow this comparison.

We have identified a number of issues with the methodology that Ofgem has employed to calculate returns. These issues include:

- The analysis uses a financial year average to deflate costs. Revenues to compensate for cost movements are based upon the inflation measure contained within the licence (July to December) which has outturned at a rate below the RPI value. This means that companies have not been compensated for the true movements in costs, which will deflate the actual returns whilst this analysis will exclude the impact.
- The opex analysis excludes related party margins, and variations in pass through costs, both of which represent actual costs but are represented in the analysis as out-performance.
- The capex analysis uses RAV additions rather than regulatory capex

- The incentive mechanisms use an average of the first three years data to calculate the final two years results. We believe that incentive revenues, particularly under the losses mechanism will fall significantly over the final two years.
- Pensions deficit repair costs are likely to be significant over the next two years. This will decrease the total returns. ERDCs which are incurred to reduce costs have been excluded.
- The calculation of the debt out-performance assumes that debt costs track the movement in real interest rates. The evidence from the debt markets illustrates that there is a significant disconnect between real interest rates and actual debt costs incurred. The issue of relatively high cost historic debt has also been excluded.

Ofgem describe an approach which appears to utilise the components of allowed returns in the DPCR4 financial model to calculate return on equity. We suggest that this approach will not allow meaningful comparisons with actual returns made by the DNOs. The concern is that the Ofgem methodology does not enable the differentiation between returns generated in the modelling (because of simplifications or assumptions employed) and returns generated by actual performance. Our approach, discussed in the company bilateral presentation, utilises actual revenues and costs and will produce a result which will be more aligned with the conventional calculation methods as used by investors in the sector.

At present the analysis uses actual and forecast data which have been provided in different submissions and contain differing assumptions. It is necessary to ensure that historic, future and allowance data are reported on a consistent basis. The analysis at present does not meet this requirement.

### **5.4.3 Interpretation of results**

Ofgem note that the three main drivers of performance are variances from allowed opex, the losses mechanism and out-performance of the allowed cost of debt. It is notable that very few companies out-performed the DPCR4 opex allowance; in the case of ENW, marginal out-performance has been driven by efficient disposal of assets. Out-performance reported on the allowed cost of debt using interest rate movements and excluding the impact of debt premium is highly unlikely to represent the financing of any DNO. This value also represents around 106bps of reported out-performance. We suggest that this methodology and the use of a modelled level of equity (which also represents a modelled assumption based upon a notional DNO) devalues and distorts the exercise; a comparison of the actual return on RAV would be more robust. In the case of the losses mechanism, Ofgem must recognise that this specific incentive mechanism was excluded from the initial 7.5% return on equity allowed at the price control. The returns received by companies through the losses mechanism are due to factors over which they have limited influence. The mechanism is symmetrical and the inherent volatility in the losses data could have resulted in an equal and opposite effect (as noted by one DNO's returns under the mechanism). This level of risk is not commensurate with the risk profile of the core business and therefore with WACC. The properties of an incentive encourage appropriate behaviour at a price that customers are prepared to pay for it by enhancing the return on equity.

Excluding the impact of the two incentive mechanisms (losses and QoS) reduces the total returns to 8.96% for ENW

Ofgem are comparing the results of the RORE modelling exercise against the standard DPCR4 allowed return on equity of 7.5%. We have previously suggested that Ofgem needs to consider the impact of the additional WACC uplift of 0.175% allowed as part of the IQI mechanism as this represents an additional allowed return on equity. Ofgem suggested that the allowance was granted ex ante and therefore is not a factor in assessing outturn variance. We suggest that this uplift was part of the price control package which represents allowed levels of return contained within the period. To exclude this element suggests that a DNO has out-performed the return on equity by 41bps (which is more than the average impact of the QoS incentive or average capex out-performance). Comparing the aforementioned 8.96% with the allowed rate of return of 7.91% suggests that ENW has out-performed the core package by 1.05%. Given the concerns with the calculation of debt out-performance, this suggests that the core regulatory package has delivered the expected returns.

Part of the Ofgem challenge was that “where companies have earned well in excess of the assumed norm, it is not clear what customers have received in return - either in terms of better service or greater efficiency”. It would appear that Ofgem has adopted a very narrow definition of customer service. The entire DNO operation is geared around delivering a service to the customer. There are very obvious elements including the quality of supply and telephony incentive mechanisms, but the DNO also provides efficient current operations, availability of capacity for additional services, and efficient investment for future customers’ services.

#### **5.4.4 Impact upon incentive properties and final settlement**

Ofgem has suggested that it may be appropriate to place caps and collars on the individual incentive schemes. This may provide some protection for customers and DNOs in the event of unforeseen variations in performance but may have two important consequences for the price control dynamics. Firstly, capping the exposure of companies (and customers) may result in differing incentive properties for each of the DNO’s (as witnessed under the IIS mechanism). Secondly, the capping of incentive revenues may distort the behaviours encouraged under a specific mechanism. This will therefore require careful consideration that the constraint does not override the power or properties of any specific mechanism. This also illustrates a key issue around the design of specific incentive mechanisms. The provision of a cap and collar is no substitute for an effective and appropriate incentive mechanism. A number of the issues around the losses mechanism could be resolved through appropriate mechanism design rather than relying upon a cap on total returns.

#### **5.4.5 Role of RORE in future settlements**

Ofgem has suggested that the RORE mechanism will be used to calibrate future settlements and will help to change the focus from the WACC towards recognising the settlement as a complete package. In the various meetings with Ofgem since the publication of the policy paper, there has been a broad acceptance that the current range of returns is reasonable.

It is important to recognise that the caps and collars may not be easily transferable across price controls. The present IIS mechanism contains a cap and collar based upon the percentage revenue exposure. Simply translating this into an equivalent RORE exposure rate is simple but the link to the movement of the equity portion of the RAV will produce differing risk profiles (dependent upon the relative movement in RAV).

Comparing measures and performance across price controls will also be difficult if the prescribed gearing level is adjusted. Setting a maximum cap based upon an adjusted gearing level will produce differing exposure rates and possibly differing incentive properties.

### **5.5 Cost of capital (5.6 – 5.15)**

Ofgem's stated objective for DPCR5 is a more holistic view of the price control settlement "to avoid too narrow a focus on the cost of capital decision". As demonstrated in the Ofgem RORE analysis, the largest value driver for a DNO is the assumed return on equity (and therefore the Weighted Average Cost of Capital). It is important that Ofgem allow a sufficient cost of capital to encourage and retain investors. Incentive arrangements provide additional funding to generate business cases to encourage appropriate behaviours and should not be utilised as a method of funding core business requirements. DNOs are likely to require large scale capital programmes in DPCR5 and therefore require access to capital markets on reasonable terms. Setting an appropriate cost of capital is a key element in gaining access to those funds.

Ofgem's commitment to retaining the methodology for calculating the cost of debt and equity and maintaining a post-tax approach eliminates a degree of uncertainty from the price control process. Given the high levels of uncertainty in financial markets and increasing risk profile of the DNOs driven by that changing nature of the business, removing regulatory uncertainty wherever possible should be encouraged.

Ofgem suggest that the decision on the cost of capital will be informed by a relative risk analysis. We have reviewed the recent work by the Competition Commission for the Stansted Price Control where relative risk analysis was utilised to set an appropriate cost of capital. The CC suggested that the equity beta for the listed utility companies (specifically Severn Trent Water, Pennon, Northumbrian Water, National Grid Transco and United Utilities) had fallen from 0.47 on 14 August 2007 to 0.35 on 12 September 2008. Work by Paul Grout suggests that equity betas can be depressed by the regulatory review process itself. This may explain the decline of equity betas for the listed water companies as the water price control review is currently in progress.

At a recent seminar on the cost of capital hosted by Water UK, the UK gas and electricity distribution networks were viewed as equally risky as the water industry by investors. Previously, the water sector was viewed as the more risky industry due to the scale of the capital programme and inherent operating risks. Changing investor expectations should not be overlooked in the price control review.

Ofgem will need to be mindful of the developments in the water price controls as the two sectors are likely to be competing for the same group of investors. Unfavourable terms compared to a similar investment are likely to constrain a DNO's ability to raise

sufficient finance to deliver its required outputs at the assumed level of cost. The seminar also suggested that the 78% of investors surveyed believed the key risks for the utility companies were in the regulation or management of the companies.

Both the Policy paper and the recent work by the CC assumes that conditions in the financial markets will “return to normal” at some point. Whilst it is highly likely that the markets will stabilise at some point, it is not known at what rate/level the markets will settle, and there can be no certainty that this will occur before 2015. Given that one of the suggested drivers of the current instability was driven by the mispricing of risk, it is reasonably certain that the cost of raising capital will be more expensive at all levels and carry more stringent conditions.

### **5.5.1 Cost of equity (5.7 – 5.8)**

The NERA DNO cost of capital report for DPCR5 commissioned by the ENA followed a similar methodology to that employed by Ofgem at DPCR4 in that it used a number of methodologies to derive an appropriate cost of equity. We suggest that this is a sensible approach which produces a balanced view whilst minimising the impact of any individual mechanisms flaws. The NERA paper suggested a real post tax cost of equity range which we suggest is not inconsistent with the DPCR4 settlement given the increased risks placed upon the distribution networks which are long term businesses and attract investors with long term requirements. Retaining and attracting investors to provide adequate funding to improve the network and maintain prescribed gearing ratios should lead Ofgem to conclude that it would need exceptional evidence to move away from the current range. We suggest that the current increase in the cost of investment grade debt (and the future cost of investment grade debt) must lead to an increase in the required return on equity, since equity holders are the residual claimants after bondholders. This would suggest that Ofgem should be considering values towards the top of the range.

As previously noted, research conducted by Paul Grout has suggested that regulatory reviews depress betas until the process is completed and then begin to ramp up again leading into the next review. Ofgem needs to be mindful of this impact and use a sufficiently long period to ensure that the cost of equity is set at an adequate level.

### **5.5.2 Cost of debt (5.9 – 5.13)**

The Policy paper contains a detailed discussion on the issue of debt indexation. Ofgem conclude that interest rate risk is best managed by DNOs since indexation of debt costs disincentivises DNOs to manage these costs effectively on behalf of the customer. There are also practical issues around defining an appropriate index.

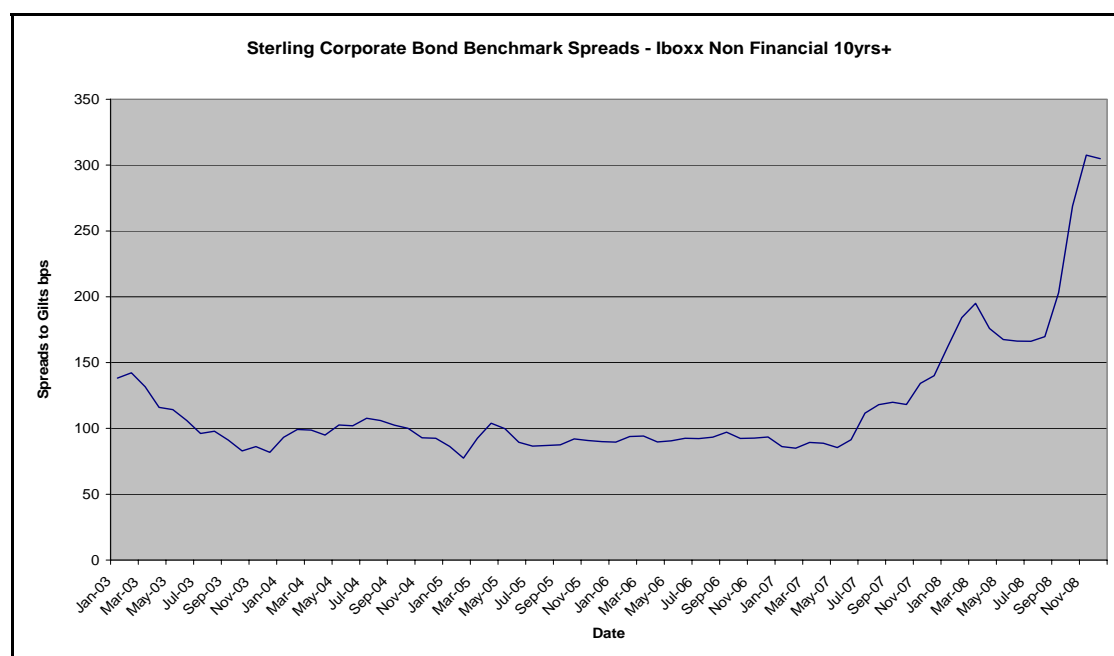
Ofgem will have noted the continued disruption in bank finance and debt capital markets through 2008 and into the beginning of 2009 that provide upward pressure on any current estimate on the cost of debt. For the record, we list some of these factors below. We note that continued evidence of these pressures on the cost of debt, around the time of the final determination, may make the adoption of some kind of debt trigger mechanism attractive. We therefore provide additional commentary on how we consider such an approach could be workable, in view of the acknowledged difficulties. In the longer term we would expect a return to the pure incentive-based approach for DPCR6; however the operation of a debt trigger mechanism will, we

believe, give added visibility to the component debt costs going forward. This is important since it is likely that debt raised during DPCR5 will continue into DPCR6 and beyond.

### 5.5.2.1 Recent debt market trends

#### 5.5.2.1.1 Widening of credit spreads

Since July 2007 there has been a continued increase in the secondary trading levels for existing corporate bonds and the related new issue pricing levels. The graph below illustrates the trend in the spreads to benchmark gilts in basis points.



#### 5.5.2.1.2 Restricted access to debt market

During the autumn of 2008, for the first time since the Russian debt default crisis in 1998, we have seen the debt capital markets effectively closed to new issuance, highlighting the need for DNOs to maintain adequate liquidity headroom. The related costs of maintaining headroom, either by way of pre-funding or un-drawn committed bank facilities have increased.

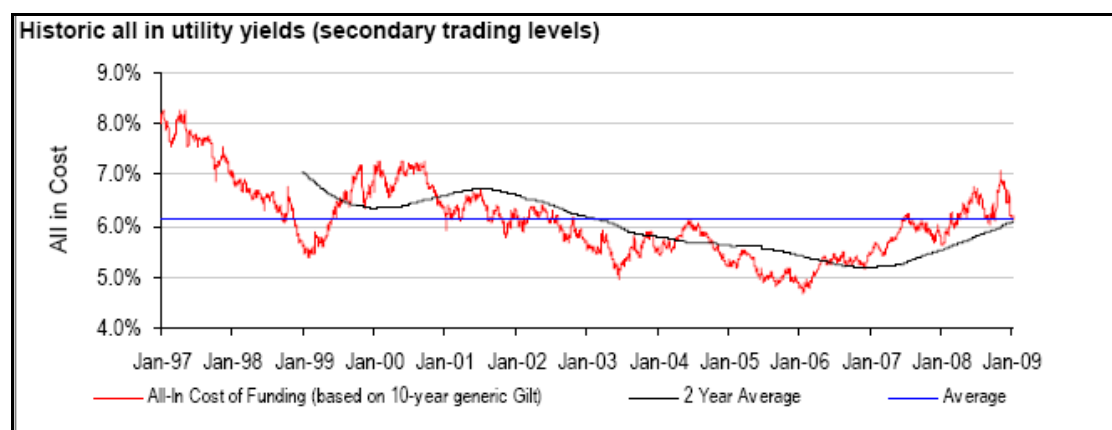
The interest rate differential between borrowing rates and deposit rates has widened given the widening between inter-bank rates (Libor and Libid) and the Bank of England base rate.

Banks charges for maintaining committed credit facilities have increased as a result of both the increase in credit spreads to reflect increased perception of risk, increased

bank capital charges, to restore depleted balance sheets, and regulatory changes under the Basel II Bank for International Settlements regime. Here un-drawn commitments are now weighted in the same way as fully drawn lines and so non-utilisation fees have increased from around a third of the margin to around three quarters. The combined effect is to increase commitment fees from a range of 0.20%-0.50% to 1%-1.5% of the facility amount; and corresponding drawn margins from <0.5% to 2-3%.

### 5.5.2.1.3 All-in issue costs flattered by gilt yields at all time lows

The effect of the widening corporate credit spreads has been significantly mitigated by the opposite movement in benchmark gilt yields, so that the all-in costs to issue new bonds have moved back above historical averages (from all time lows in 2006-07) but have yet to move significantly higher.



Source: HSBC Bank plc

Gilt yields reflect the very significant cuts in short term interest rates announced through the autumn and winter of 2008/09. However concerns around the levels of new government debt (gilt issuance) and with longer-term inflation expectations remaining at 2.5%-3% there is upward pressure on gilts. For example the 10 year gilt increased by 0.7% from the all time low of 3.017% on 31 December 2008 to 3.701% one month later on the 30 January 2009. These all time low gilt yields have been the reason why all in costs remain just about at long-term averages. There is no certainty that 10 years+ gilt prices will not continue to increase given the macro-economic factors; whilst there is little to suggest credit spreads will contract in the medium term.

### 5.5.2.1.4 Reducing bank market liquidity and capacity

The well publicised problems of the world wide banks has reduced those banks capable and willing to participate in syndicated loan facilities and increased significantly their demands for pricing to increase their return on capital.

There are related impacts on the bank's capacity to enter into long dated swap contracts to meet a DNO's hedging requirements. This is specifically true as regards index-linked derivatives where up until 2008 banks were willing to enter into long dated index linked swaps; to essentially create a synthetic index linked bond. This market has completely dried up and therefore the opportunity for DNOs to structure a proportion of their debt on long term index-linked terms is extremely limited and only now including increased credit margins.

Access to the bank and debt capital markets is fundamental to our business model and Ofgem's cost of debt assumption must be sufficient to allow us to service the existing debt, raise new debt and refinance expired debt and committed facilities. The scale of the DPCR5 capital programme suggests that it is more important than ever to ensure efficient access to the markets.

#### **5.5.2.1.5 Risk free rate assumptions**

One of the key issues being debated at present is the risk free rate (RFR). It is widely recognised that the traditional RFR calculation methodology using the index linked gilt market is working inefficiently due to the actuarial requirements under the minimum funding requirement, IAS19 and FRS17 which have depressed UK gilt yields below the true RFR and below historic levels included within regulatory settlements. Recent work by NERA suggested that an alternative approach was available to calculate a RFR based upon swap rates. We recognise that the CC raised some initial concerns with this work, but it is important to note that the CC accepted that ILG market was not working efficiently. Ofgem has not discussed its views on this matter and it may be useful to understand the Ofgem position before the initial proposals.

In the Stansted determination, the CC proposed to adopt a target investment grade credit rating of A-, noting that companies with BBB category ratings have been able to raise new debt finance if they are prepared to meet lenders' demands on price, but must plan more carefully the timing of new issuance and will typically need to access both the bond and bank markets. By contrast, companies with A category ratings appeared to have been less affected by the credit crunch and are better placed to raise new capital at a reasonable cost. The CC also suggested that it needed to target a comfortable IGCR after allowing for absorption of downside risk. This proposal may be one way of securing long term lower rate debt for consumers whilst providing increased short term revenues to produce higher credit ratings (with the associated lower cost long term debt). The alternative is a targeting a lower IGCR with associated higher cost debt which, on a whole life cost basis, may be more expensive for customers. We suggest that Ofgem should test financeability at A-ratios, as this approach should produce the lowest cost long term solution for customers

#### **5.5.2.2 Debt indexation and debt triggers**

We make the following observations on sections 5.10 to 5.13 of the Policy paper:

#### **5.5.2.2.1 Weighted average cost of debt**

Arguably any move to introduce a degree of indexation would require Ofgem to disaggregate a DNO's actual cost of debt into the component debt instruments; in order to identify which component(s) should be indexed or linked to a debt trigger.

#### **5.5.2.2.2 Long-term debt has long term costs**

In the event that Ofgem seeks to implement a debt trigger to allow for a downward revision in allowed cost of debt; should market conditions improve, then this would act as a strong disincentive to issue new debt in the meantime, with DNO's being forced to judge the "top of the market". Any long-term debt issued at a prevailing price which later proves to be comparatively high is fixed by the DNO and is then a constant cost until maturity. Revising the allowed cost of debt downwards, with the benefit of hindsight, provides inadequate returns to service this debt. Therefore any proposal to reduce an initial allowed cost of debt would need a mechanism for "pass through" of the costs of any debt issued in the period after 2008. This requires the disaggregation process set out in (a) above.

Whilst it may appear that an alternative solution is for DNOs to issue short term debt (<5-years) this increases the re-financing risk and there is currently little appetite from bond investors for shorter maturities.

#### **5.5.2.2.3 Re-opener to deal with a "perfect storm"**

As set out above there has already been a paradigm shift in prevailing credit spreads payable by A/BBB rated corporates from sub 100 basis points in 2006/7 to 275-350 now. However the actual effect of this is being significantly mitigated by government gilt yields (and shorter term inter-bank rates) at all time lows.

However the two are not necessarily correlated and concerns about medium term inflation could return gilt yields to historical (1998-2007) norms of c4.5-6% whilst credit spreads remain above 2.5% putting overall nominal debt costs in the 7-8% territory. A sustained period of debt costs at this kind of level would necessitate an appropriate adjustment to allowed costs of debt and a debt trigger to allow a re-opening of the price determination would be appropriate.

We believe that Ofgem may find it difficult to set a fixed cost of debt for the DPCR5 period as any new rate which recognises current financial market turmoil (which may or may not be so acute by the time of Final Proposals) may also give unacceptable scope for future company gain.

The DPCR5 price control must encourage equity investors by giving the reassurance that should the costs of new debt be greater than assumed in the price control settlement, a mechanism exists for Ofgem to fund these costs, where companies have acted appropriately. This approach can also protect customers from the risk of over compensating DNOs, should debt costs fall more quickly than expected.

### **5.5.3 Gearing (5.14 – 5.15)**

Decisions on the gearing levels of the DNOs should be made reflecting the present market conditions (to allow access to the debt markets at reasonable cost) and the requirement to maintain an adequate equity buffer to protect customers. Ofgem's conclusion that a substantial departure from previous decisions was unwarranted appears reasonable. Several price control settlements have recently incorporated similar gearing rates, whilst referencing the appropriateness of the balance between debt and the protection that equity provides.

The gearing assumption at DPCR4 was based upon the efficient financing structure of a hypothetical DNO. This was drawn out through discussions with credit rating agencies and utilising appropriate ratio analysis. Discussions with the various rating agencies suggest that variations away from the DPCR4 level may increase the borrowing costs for DNOs. We recommend that the DPCR5 rate should be set at levels commensurate with the expectations of the various agencies.

## **5.6 Financeability and financial modelling (5.16 – 5.21)**

Ofgem suggest that NPV positive financeability uplifts are unnecessary and should be avoided. We agree that in principle, uplifts can be avoided by setting an appropriate cost of capital. It is important that Ofgem ensure that the financeability tests employed at the price control mirror those utilised by the rating agencies.

### **5.6.1 Depreciation (5.17 – 5.18)**

Ofgem has utilised depreciation lives to correct previous financeability issues relating to the depreciation of pre vesting assets. Ofgem noted that this has brought the depreciation rates out of line with accounting rates. This is not necessarily an issue in itself as the majority of the Ofgem accounting rules and definitions do not follow normal accounting practice. It is likely that the current discussions on equalisation of incentive rates represent further movement away from statutory accounting capitalisation rules. It is also important to consider the impact upon the 15 year smoothing adjustment applied when the asset lives were shortened and the impact of moving the life again before the cycle completes. We suggest that Ofgem should retain the current 20 year depreciation profile for DPCR5. If Ofgem are minded to change the asset life, it should be considered as part of the RPI-X@20 review.

The RAV and its remuneration through the price control are regulatory devices within an overall framework. The important feature is that the RAV holds the value of past costs for which the DNO has an assurance of full recovery in the fullness of time. When that value is returned to the company is a matter for Ofgem to consider in the context of minimising the cost to customers arising from shareholders and debt holders expectations and the 'charges' for extended financing periods (ie the additional exposure to the WACC).

The discussions relating to depreciation cannot be divorced from the treatment of opex and capex costs within the regulatory accounting mechanism. The proposals to fix the percentage of "totex" entering the RAV may lead to a significant proportion of traditional or statutory opex costs funded via the RAV.

### **5.6.2 Financial modelling (5.19 – 5.20)**

The DPCR4 financeability tests were set “by calculating and assessing certain financial ratios that are used by credit rating agencies and others in the financial community to assess the financial strength of a company”. In DPCR4 this included FFO/interest, retained cash flow/debt and average net debt/average RAV. It is important that Ofgem continue to reflect the view of financeability held by the various financial institutions. One of the most important ratios utilised in recent years by rating agencies for utility companies is the Post Maintenance Interest Cover Ratio (PMICR). The major agencies have adopted this measure to reflect in sizeable maintenance requirements of a utility company and the impact upon cash flows and therefore ability to pay interest. In the recent Water UK investor survey, PMICR was cited as the most important financial measure utilised by investors. We understand Ofgem’s concern with the utilisation of this mechanism, as the specific tool utilised by Ofgem to correct financeability issues (namely accelerated asset lives) is effectively removed from the measure by the deduction of regulatory depreciation. This does not alter the fact that the agencies will monitor this ratio when assigning a credit rating. We suggest that Ofgem should follow the precedent set at DPCR4 and utilise the ratios used by the investment community.

### **5.6.3 Profiling (5.21)**

Any decision on the profiling of revenues will need to be made reflecting the balance between the cash flows required for a large capital programme, the desirable objective of stable charges to customers and minimising the potential impact of a large PO increase in the first year of DPCR5 while energy bills are still a political issue. Given the uncertainty over energy prices and capex programmes, Ofgem’s decision to delay a decision appears sensible. Ofgem must be mindful of the need for financeability adjustments.

## **5.7 Treatment of taxation (5.22 – 5.30)**

Ofgem have committed to maintaining the current approach to setting tax cost allowances. We believe that this incentivises the DNOs to operate efficiently and therefore reduce the risk and cost to customers. Ofgem’s proposal to include a symmetric trigger mechanism to protect customers and DNOs against potential movements in taxation rates is consistent with the incentive based approach and is supported by ENW.

### **5.7.1 Claw back of tax benefits of excess gearing**

We agree with the ex-post approach and with the principles of a tax gearing claw back adjustment. We welcome feedback following the responses to the publication of the 5 December letter discussing a review of a number of the practical issues surrounding the mechanism. It is important that Ofgem operate this mechanism in a consistent and predictable manner to reduce regulatory risk.

### **5.7.2 Sharing of tax benefits arising from legislation changes**

We agree that changes in tax costs as a result of tax legislation/practice changes outside the control of the DNO should have some form of sharing mechanism (both

upside and downside). This is especially the case given the recent economic climate which has given rise to unforeseen tax legislation changes to counter a worldwide credit downturn. We also agree with a de-minimus amount whereby it is not necessary to re-open or make post-DPCR period adjustments for such amounts. We would welcome Ofgem's view on the level of de-minimus and would suggest a measure that is linked to a DNO's specific financial indicators (eg as a percentage of RAV) to cater for the fact that a fixed de-minimus amount would not be equitable.

### **5.7.3 Modelling of capital allowances**

We would recommend some checks and balances to ensure that all appropriate spend is being pulled into the spreadsheet. The table should include all spend that is treated as capital for tax purposes, specifically faults and other indirects that are capitalised.

We note the intent to use a common percentage allocation approach based on an industry average of the percentages across all DNOs. We look forward with interest to the percentages that Ofgem are proposing to use. We note that Ofgem have indicated that the difference between the industry average percentages and each DNO's specific percentages is a 14% differential on capital allowances related to capital spend. It is our view that this is not an insignificant difference between DNOs and we would like to reserve judgement until we have had a chance to consider the percentages that Ofgem are proposing and analyse their potential impact.

### **5.7.4 Changes to IFRS in DPCR5**

We prepare and file financial statements in accordance with International Financial Reporting Standards ('IFRSs') as adopted by the European Union. ENW is unique in this respect as all other DNOs prepare and file financial statements under UK Generally Accepted Accounting Practice, (United Kingdom Accounting Standards and Applicable Law).

It is anticipated that, during DPCR5, UK GAAP will converge with IFRS and thus all DNOs' financial statements will be prepared on a consistent and comparable basis, however in the medium term ENW will be exposed to the impact of changes and enhancements to IFRS which could impact upon the preparation, presentation and cash flows of the business.

In addition, due to the above mentioned UK conversion project and also the anticipated US GAAP conversion, there are a significant number of IFRSs and interpretations which are due to be endorsed during DPCR5. As these pronouncements are not yet endorsed the impact is not necessarily clear to us at present. The main areas of concern relate to changes with regard to debt instruments, fair value accounting and pensions which can impact directly on taxation and cash flows.

Therefore, to ensure that ENW has the necessary safeguards in place, Ofgem needs to ensure that this uncertainty is treated in the same way as any possible changes to UK tax legislation. This would therefore ensure that a mechanism is built into DPCR5 which would allow us to re-examine the financial impact of any changes in IFRS.

## **5.8 Regulatory Asset Value (5.31 – 5.34)**

The construction of the RAV needs to follow a transparent and predictable treatment. In several specific areas, certain costs have been excluded from RAV which we believe have been incurred on an efficient basis.

We have developed an innovative business model that is designed to yield efficiency improvements that can set a benchmark to benefit all electricity distribution customers in Great Britain. We are investing to ensure the sustainability of this business model and the associated benefits. We have agreed to treat UUES as a Related Party in order to ensure Ofgem continues to have access to all the information required to undertake comparative regulation and ensure customers continue to benefit from the regulatory treatment of indirect costs. A further effect of this treatment as a Related Party is to disallow any margin earned by UUES. This treatment was not applied by Ofgem in recent decisions regarding a very similar business model. The ENW business model will be rendered unsustainable if the regulatory treatment applied is not brought in line with the precedent determined by Ofgem for Northern Gas Networks and United Utilities Operations Limited. Ofgem should recognise UUES margins as genuine costs to the business that reflect efficient operations which will provide benefits for customers.

We have been encouraging the development of competition in connections for several years. Taking advice from a wide range of stakeholders, including Ofgem, we have made considerable efforts to restructure our connections activities to demonstrate that all connections providers are treated equally and served well by our non-contestable activities including leading trials of innovations such as the live jointing scheme. For some time now we have been concerned that the regulatory treatment of connections has been inappropriate and potentially working against the further development of competition, particularly in the ENW distribution services area. In previous discussions we have suggested that the following steps should be considered:

- Removing the regulatory incentive to price at cost
- Reviewing the imbalance between the treatment of connections indirect costs and the associated customer contributions
- Removing the regulatory penalty applied because of the success of a competitor in the connections market

We believe that these issues need to be corrected as part of the DPCR5 settlement.

## **5.9 Pensions (5.35 – 5.43)**

We welcome the Ofgem statement that the pension principles are appropriate and that further work will focus upon the application of the principles and transparency of management of the schemes. As identified in the policy paper, the pension schemes have various elements which provide protection to customers.

Varying contribution rates do not mean the pension principles are not being appropriately applied. Pension scheme funding legislation now enshrines a scheme-specific approach, with the former “one-size-fits-all” approach having been discredited.

We would like to see consistency of pensions treatment agreed for DPCR5 with a longer term acceptance of the established pension principles. Any consideration of fundamental change should be incorporated into the RPI-x@20 review. Making any major changes for DPCR5 would indicate a short term approach to pension funding and result in a more cautious approach by Trustees, increasing the risk of surpluses arising.

#### **5.9.1 Pension deficit recovery**

Appendix 10 of the policy paper describes the current views on the appropriate treatment and recovery period for pension deficits. It is important to recognise that a proportion of total pension costs are funded via the RAV and therefore payable over a 20 year timeframe. If a pension scheme has been underrecovering to the extent that it creates a significant deficit, any deficit cannot be funded via RAV additions and comply with the pension regulator requirements.

We believe that the funding must be provided in line with the actuarial recommendation as accepted by the Trustees. The Pension Regulator has set guidelines for deficit repayment with a trigger point for further scrutiny of 10 years. The 10 year period is not a proposed repayment period, just a trigger point beyond which they will consider each scheme on a case by case basis. The Trustees of the individual schemes are best placed to make the assessment and as such funding should be provided in line with the accepted repayment profile. Differences in scheme maturity, investment strategy etc may mean that different periods for deficit repair are appropriate and that funding should be in line with this.

#### **5.9.2 Ex-post adjustments for DPCR4**

Adjustment for the actual pension costs treated as opex (42.3%) is acknowledged. We believe this should be adjusted in the year of correction. Spreading over the next 5 years does not seem appropriate, especially given the forecast rise in pension costs.

#### **5.9.3 Capitalisation into RAV**

We believe there are strong arguments for different treatment of ongoing and deficit repair treatments due to the differing financial treatment DNO's are forced to take in respect of these costs.

Deficit repair payments are based on actuarial assessments and agreed with the trustees, requiring significant lump sum cash payments. It is difficult to assess any attribution of these costs between direct and non-direct activities. We believe the most appropriate regulatory treatment would be to fund these costs as opex, matching the DNO's cash flows.

#### **5.9.4 Appropriate actuarial valuation**

Valuations used for funding must be based on actuarial valuations as this matches the cash deficit funding. Use of 'best estimates' is not appropriate as a basis of funding. Additional actuarial valuations will be expensive and timely, adding little value as cash payments will only be altered after the next full triennial valuation has been

completed. The option of a re-opener once the next triennial valuation is complete would seem the preferred option.

#### **5.9.5 Pension administration and associated costs**

As noted earlier in our response, we believe that the DNOs are incentivised via the various mechanisms to efficiently incur costs on behalf of customers. As the costs are largely out of the control of a DNO or are immaterial, retention of the current treatment is desirable. We recognise and agree that treatment must be normalised whether paid by the licensee or via the scheme contributions.

#### **5.9.6 Scheme mergers**

During the sale of UUE, we worked hard to ensure that only the pension liabilities associated with the distribution business were sold and ultimately became part of ENW (the balance remaining the responsibility of UUG plc). In this circumstance, as we have already discussed and agreed in outline, the logical application of Principle 2 would be to increase the proportion of ENW pension costs subject to pass-through to 100% of pension costs. We therefore welcome Ofgem's review of the split of schemes between regulated and non-regulated business.

#### **5.9.7 Stranded surplus**

We suggest that whilst stranded surpluses are unlikely in the present climate, agreeing a long term approach to pensions will help prevent this occurring.

#### **5.9.8 Buyouts**

We believe that Trustees are not currently seriously considering such options because the regulatory treatment of the one-off costs of such a move is uncertain. We would welcome providing Trustees with the opportunity to consider both pensions buy-out and buy-in as options, through the clarification of regulatory treatment. We believe that application of Principle 1 would suggest that the costs associated with pension buy-in and buy-out could be treated as "efficient and economic" where an appropriate cost-benefit analysis for customers can be shown and, therefore, allowed as pension costs to be funded by customers. We agree this is unlikely to occur in the current market.

## **6 Process and Timetable**

### **6.1 Chapter Summary**

We agree with Ofgem's proposed price control process and are broadly supportive of the proposed timetable. The engagement process with Ofgem to date during DPCR5 has been well managed and very effective. In particular, the use of working groups to discuss emerging proposals by stakeholders, DNOs and Ofgem (such as the Environmental Issues Working Group) should continue and be extended to issues such as Comparative Efficiency and Allowance Setting Mechanisms. We welcome Ofgem's proposal to publish a methodology document in May and their recognition that it may be necessary to provide an update in September on those issues that remain unresolved at Initial Proposals. It is imperative that Ofgem recognise that the amount of information being required of DNOs in a relatively short period of time is substantial and that any changes to requirements and/ or timetable changes or delays to specifying exactly what is required of DNOs may result in poor quality or delays to submissions.

### **6.2 Answers to Ofgem's Specific Questions**

#### **Question 1: We invite views on which format stakeholders would find most useful for the Ofgem workshops to be held in January 2009**

See section 6.5.2 of our response.

#### **Question 2: We invite views on our proposed process**

See section 6.3 of our response.

### **6.3 Process**

We agree that the process outlined by Ofgem represents a sensible approach to managing the price control review with appropriate milestones.

We believe that the bilateral meetings have been positive and allow both parties to debate the key issues in a constructive manner. This approach has been mirrored in a number of different areas (eg the environmental issues working group and the finance working group). We would suggest that this approach represents regulatory best practice which should be extended to other areas such as comparative efficiency.

We welcome Ofgem's acknowledgement that more work is required on developing the processes for assessing expenditure requirements and agree that publishing an additional methodology document in May 2009 providing an update on proposed approach is sensible. We are concerned that the scope of the May paper has expanded over the past few weeks to include several finance methodological or policy issues. It is important that this paper is produced in early May given the proximity of

the Initial Proposals. If necessary, we would suggest that Ofgem could publish the finance sections in late April and comparative efficiency sections at a later date.

We are particularly pleased to note Ofgem's recognition that there may be a need to publish details of material changes in a September update. We agree that the scope of this document can be limited to those items that have changed materially since Initial Proposals. Alternatively, issues could be dealt with on a case by case basis through a series of "Chief Executive" letters.

We agree that it is appropriate to publish specific impact assessments for key decisions.

We support Ofgem's proposal to publish draft licence modifications with the Initial Proposals wherever possible.

#### **6.4 Timetable**

We agree that Ofgem's outline timetable is broadly sensible. It is, however, very important that Ofgem recognise the resource intensity of many of the tasks and that DNOs will plan their price control activities on the basis of this timetable. Material changes to the timetable will limit DNOs' ability to deliver good quality submissions on a timely basis.

In particular, the concurrent requirements for DNOs to produce Reduced RRP, FB PQ update and full RRP will require very detailed planning. DNOs need to understand the format of the reduced RRP as soon as possible; our experience of completing RRP is that any changes to table format require significant work to ensure that costs are correctly mapped. Late specification of requirements may lead to shortcomings in submission quality or timescale slippage.

#### **6.5 Stakeholder engagement**

##### **6.5.1 General**

We support Ofgem's continuing focus on ensuring that stakeholders are able to fully engage in price control review discussions.

##### **6.5.2 January workshops**

We agree that the workshops in May 2008 were a useful opportunity for wider stakeholders to enter into debate on DPCR5 issues. The January workshops adopted a different approach which allowed longer discussions on the core chapter issues. This allowed stakeholders to discuss the options available to Ofgem and the implications of those decisions. We believe that this approach was more appropriate for this event as the content and debates had developed from the earlier workshops.

At the January workshops, Ofgem suggested that they would hold an investor conference to discuss the various issues raised in the financing chapter. We endorse this suggestion and believe this event will engage a different group of industry stakeholders.