DPCR5 Policy Paper

Central Networks' Response

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The photograph on the front cover was taken by employee Andy Icke, who is an Environment Advisor for Central Networks.

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Introduction and Executive Summary

A Shared Vision of Success

In our response to Ofgem's initial Distribution Price Control Review (DPCR) 5 consultation we showed how our business' objectives are closely aligned with Ofgem's. The policy document reinforces those priorities, challenging the Distribution Network Operators (DNOs) to be innovative and play a full role in helping to tackle climate change. We want to make sure that our business continues to deliver an excellent customer experience at the lowest possible cost, both now and in the future.

We also believe we have a key role to play in the delivery of the Government's 2020 carbon reduction targets, building upon the innovation in DPCR4 where Central Networks constructed the UK's first Registered Power Zone (RPZ) allowing low carbon generation to connect to the existing network with minimal cost.

Our vision of success for DPCR5 is therefore that the regulatory framework evolves such that Distribution Network Operators (DNOs) can:

- continue to provide a safe, reliable and efficient network in the face of significant uncertainty about demand and costs of service provision;
- devote much needed resource to a step-change in engaging with our customers and stakeholders and in particular being proactive in supporting connection of distributed generation;
- take an innovative and longer term perspective as to the construction and operation of networks, having the flexibility to respond to future requirements , without being restricted by differential incentives for opex and capex;
- build a sustainable business model with a workforce which is sufficiently skilled and resourced to meet these challenges in association with replacing an increasing proportion of our assets which were installed in the 1950s and 1960s and hence reaching the end of their life ;
- be appropriately rewarded to finance this substantial 15-20 year investment phase and attract sufficient equity funding.

Responding to the Economic and Environmental Challenge

Dealing with unprecedented levels of uncertainty is one of the critical priorities to address as we work together to finalise the DPCR5 price control. The energy landscape is changing rapidly, and the global economic crisis adds to this volatility to an extent that is unprecedented in the history of RPI-X regulation.

During such change we agree that unnecessary expenditure and the consequential burden on customers must be avoided, and that companies will need to demonstrate value for money through the delivery of wider outputs. Nevertheless, Ofgem's duty to protect the interests of customers and society also means balancing short and longer term goals, a behaviour that Ofgem not unreasonably expects from companies. The challenge for DNOs, Government and Ofgem is to work together to create a price control that is able to respond to an economic and political landscape which in only a few years' time could be very different from today.

Our DPCR5 business plan recognises the economic uncertainty ahead. We have subjected our reinforcement expenditure plan to external scrutiny and have challenged ourselves hard on the need to invest. We have adopted a new approach to assessing this need, linked to robust outputs for load reinforcement that will see us taking on more risk. However, the aspiration expressed in the consultation document that new technologies will drastically reduce expenditure for network renewal and maintenance of supply security is overstated, at least in the short term. Whilst we need to engage with customers and trial new technologies and ways of operating the network in DPCR5, any significant implications are unlikely to be encountered until DPCR6.

Meeting Stakeholders' Requirements

DPCR5 must enable DNOs to adequately fund sufficient investment to maintain the network and meet sufficient [statutory] levels of resilience and performance whilst delivering the expectations of wider stakeholders. As highlighted above, this needs to consider the implications for networks of the government's commitments for 2020 and a more proactive role in facilitating the emergence of a diverse local and low carbon distributed generation portfolio.

In order to ensure DPCR5 addresses the requirements of stakeholders Ofgem can:

1 Work with companies and Government to adopt a wider set of strategic priorities for DPCR5, aligned with achieving the 2020 renewable energy goals.

Innovation is not just about asset sweating. The policy document appears to suggest that new technologies are 'good to go' and that any company that is not able to make immediate use of them is inefficient and short-sighted, and should be penalised for "misjudging" the future. In reality, demand side

management (DSM) and distributed generation (DG) solutions have yet to reach widespread commercial implementation and:

- will require some up front investment, trials and risk taking by DNOs to embed into business as usual operation, and
- even when implemented, may sometimes just be a form of deferral of reinforcement spend, with a level of uncertainty remaining as to future spend.

To be able to respond efficiently and effectively to the challenge of a shift to a "smart" infrastructure by 2020, DNOs need to begin work on development and deployment of schemes on a broader basis. Although the current regulatory framework has helped immensely, it is not able to support wider development and deployment. As the policy document acknowledges, further changes are now required. There are three key steps to ensuring DNOs can respond quickly and flexibly to this change, all of which need to be supported by the DPCR5 framework:

- A concentrated period of planning and engagement, requiring resources that DNOs have until now been unable to justify commercially given the current focus on opex and lack of certainty of cost recovery under the current regulatory framework. Our DPCR5 business plan contains specific resources allocated for this task'.
- Building of demonstration projects and key partnerships early in the DPCR5 period, supported by a modified "RPZ+" scheme and the DG incentive.
- 'Business as usual' roll out of innovative solutions which reduce longer term cost but which carry more risk.

To meet this challenge effectively, companies, Ofgem and Government must agree a clear roadmap of strategic investment priorities for electricity distribution networks to meet the 2020 goals. This is not without regulatory precedent. Ofcom maintains a set of goals for facilitation of technology roll-out. Recent Californian legislation will catalyse the development and planning of a "smart" network infrastructure and will provide companies with greater certainty over cost recovery and implementation timescales.

2 Maintain a regulatory framework that recognises the increased uncertainty and risk whilst employing transparent and balanced incentives aligned with the Cost of Capital

Companies will need significant increases in investment over DPCR5 to respond to an ageing network installed predominantly in the 1950s and 1960s. Whilst we expect DNOs will start to move away from "traditional" network solutions and look to utilise demand side management and distributed generation to provide security of supply, the underlying risk of the business will increase. Consequently, a staged process is needed to manage risk, with DPCR5 being focused on improving engagement with developers and customers and trialling new schemes.

We fully accept the principle that increased spend demands greater

demonstration of delivery, and our business plan presents a complete and robust set of output measures. These are offered in a spirit of transparency and desire to improve the regulatory framework to better demonstrate "value for money" investment. We agree with Ofgem's assessment that the output framework will need to evolve over the DPCR5 period, and the use of wider output measures in the regulatory framework is in its infancy. A measured and productive dialogue, with the possibility of in-period review, will ensure that companies propose outputs that are transparent and representative of what the networks require, accepting an element of delivery risk.

Dealing with uncertainty faced by the Industry should be at the heart of DPCR5 policy development. The increased risks should be addressed via appropriate incentive design and recognition in setting the allowed cost of capital. Like Ofgem, we want to manage the uncertainty as transparently as possible, bearing in mind the three-way trade off between risk, simplicity and predictability. We see a role for revenue drivers and triggers for specific large and uncontrollable risks, with the Information Quality Incentive (IQI) mechanism and cost of capital used to manage residual uncertainty in both forecast and delivery. This would also maintain simplicity and price predictability for customers. We have developed our proposals further with the help of Cambridge Economic Policy Associates (CEPA) and have shared them separately with Ofgem. Increasing incentive strength, as Ofgem proposes, in a central band around the forecast is not the right approach as it assumes greater control is possible over small cost variations, whereas in fact it is in this area that many of the uncertainties are most likely to impact.

Ofgem proposes continuing with the existing losses measure, arguing that this represents the best available "output" measure for network losses. We would firmly disagree in that a number of factors which are predominantly outside the control of DNOs have a totally overbearing affect on the incentive, creating no link between this overall output measure and the underlying level of technical network (i.e. carbon) losses. As a result, the output incentive has in fact delivered little or no reduction in carbon emissions in DPCR4, and will not do so in DPCR5 either. There is also a significant risk that again either companies will receive large rewards or penalties for effects almost entirely beyond their control from the continued use of such a measure. The most rational and transparent approach is therefore an incentive which recognises the societal value of specific actions to reduce losses and provides a transparent reward based on a "market" value of carbon, allowing companies to clearly demonstrate to stakeholders, including Ofgem, where reductions have been achieved.

3 Recognise the unprecedented financing risk faced by companies and the importance of equity.

Two possible outcomes of the current economic crisis are plausible. One sees a prolonged downturn with slow growth recovery. Another sees recovery after two or three years, with consequentially high inflation and interest rates driven by a number of macro-economic factors, including the impact of Government action to support the economy and rapidly increasing demand for construction and infrastructure. In either case, customers and companies are potentially exposed to significant uncertainty in the form of end prices, demand for

capacity and the availability and cost of financing. In this environment of extremes, a fixed five year contract will not provide adequate protection for either customers or companies. Therefore:

- Consistent with Ofgem's desire to stimulate companies to adopt less risk-averse business models, the allowance for cost of capital at DPCR5 must recognise the need for equity financing for network investment of national strategic importance.
- Micromanagement of financial structures or pensions administration will be inefficient and counterproductive. Ofgem has raised concerns about the potential costs of financing pension deficits that have grown for reasons beyond DNOs' control. Our pension schemes are managed efficiently and effectively and are now closed to new members, any liability now being historic and driven by factors outside of company control.
- We agree with Ofgem and the Competition Commission that cost-of-debt indexing is impractical, does not properly allocate risk and creates perverse incentives. However, given the current economic and market uncertainty, we believe either a re-opener or triggers around the cost of capital will be necessary for Ofgem to fulfil its financing obligations and protect both customers and companies. The use of trigger mechanisms should be symmetrical, or any asymmetry should be reflected in the Weighted Average Cost of Capital (WACC).

Overall, the cost of capital and financeability of DNOs is essential as we enter a major 15-20 year investment phase. This will place significant pressure on DNO finances, which are likely to remain cash negative throughout this period with cash being locked into the Regulated Asset Value (RAV). The long term equity commitment and the potentially high short term risks require that returns remain attractive to investors.

Serving Customers Well, Now and in the Future

We support many of the forward thinking proposals for networks in the policy document.

In particular:

- We support equalisation of opex and capex incentives to promote innovative trade-offs between opex and capex, allowing for 'non-network' solutions such as demand side management and distributed generation where these are commercially viable. We also agree with an approach that capitalises groups of costs based on their underlying drivers (e.g. network investment costs), with clearly defined and enforced boundaries rather than an arbitrary total fixed rate of capitalisation.
- We support Ofgem's desire to broaden customer satisfaction measures and incentivise better provision of information. As thinking on the functionality of smart metering evolves, so does our understanding of the opportunities and

benefits this technology might offer. However, it is important to assess costs against the real value that customers place on the additional information and functionality provided. We will need to develop an implementation plan and funding approach as part of developing the DPCR5 framework.

- We have made, and continue to make, changes to our connections business to improve the level of service we give to our customers. We want to offer excellent service to our customers and are working towards our vision of becoming the best utility connections provider during the DPCR5 period. In order to judge this, we will continue to seek and act upon direct customer feedback through a variety of means including Net Promoter Score (NPS) and use this to lead the improvements we make.

  We support the majority of the proposals in respect of connections, although there is clearly more detail to be worked through. We share Ofgem's recognition that connection jobs are not all the same and any proposals to implement price controls on "regulated" market segments need to be worked through carefully to avoid unnecessary cross-subsidy or complication.

  Our own customer feedback aligns with that of Ofgem's, in that customers value good communication and timeliness of work. We support the focus on these aspects of connections work in the proposed market segments. We are implementing a rigorous performance monitoring framework to ensure that customer delivery continually improves year on year, and meets the expectations of our customers taken from their feedback. We must ensure that the impact on the end customer remains the priority in any of the changes that are proposed.

- We support the progress that has been made in developing cost benchmarking. However, labour cost adjustments are only really valid if they reflect London as a special case - and then only for certain types of activity as other resources are largely mobile on a UK-wide basis. We support Ofgem's proposals for assessing general reinforcement costs, which better take into account site-specific requirements.

In DPRC4, Central Networks has delivered on its promises and taken significant positive strides on customer service, asset management, cost efficiency and innovation. The next 5-10 years will provide significant challenges and uncertainty for both DNOs and Ofgem. However, with the right framework in DPCR5, Central Networks will deliver a secure and reliable network, providing an excellent service to our customers at an efficient cost, whilst developing further innovative approaches as to how the network is constructed and operated in the twenty-first century. We look forward to working with Ofgem to develop this framework over the next few months.

Responses to Questions

Chapter 1

Overview

Question 1: Do you agree with our assessment of how the DPCR4 settlement has performed in practice?

Question 2: Do you agree with the main lessons we have drawn from this assessment?

The DPCR4 settlement was offered by Ofgem as a package (first paragraph of Summary section, final proposals document) and companies accepted it on this basis. The terms of the agreement were that allowances were awarded on the basis of the minimum expenditure necessary to run an efficient business whilst maintaining existing performance standards. Central Networks is delivering this contract, improving service and managing price risk efficiently on behalf of customers. More information on this is provided in our response to Chapter 4.

Ofgem's use of return on regulatory equity (RORE) provides a new perspective to inform development of DPCR5 proposals. However, it should be noted that the principal drivers of outperformance in this measure (tax and interest) represent agreed risks that DNOs took on behalf of customers. Tax and interest together account for 1.69% of average RORE outperformance. In other circumstances, largely beyond DNOs' control, these outturn benefits could have been penalties. This has in fact happened in the case of the growth driver, where companies' revenues have been reduced.

Remaining incentives actually account for -0.11%, showing clearly that DNOs haven't earned from incentive mechanisms in the way Ofgem suggests. Companies have struggled to achieve the allowed rates of return from cost incentives given the level targets were set at and the tendency for the current framework to allocate more to opex costs and less to capex compared to the true nature of the underlying cost base, with a consequential net penalty for companies given differential incentive rates.

In the case of the losses incentive, we have already presented arguments to Ofgem showing DNO's limited physical ability to affect the overall losses measure. We strongly disagree with the assertion that DNOs will be able to control sufficiently the non-technical element of the losses measure given increasing asset utilisation (desired by Ofgem) and increasing cleansing actions by suppliers which are driving losses up. Smart metering will also add to settlements volatility as the consumption pattern reflected by profiled data is replaced by actual information. The current expectation for smart meter installations would also see them drawing communications power from the DNO's side of the cut-out, thus adding further to losses. In its current form the losses incentive doesn't and will not incentivise carbon reduction. The industry has argued the case for change in the losses mechanism and these arguments still stand.

It is also recognised that there is a significant degree of year on year variation in Information and Incentive Scheme (IIS) performance that is weather related.

Overall, the picture is of a varied set of risks which DNOs are able to affect to a greater or lesser extent and which, when taken together as a portfolio, provide the basis for which a commercial decision to accept or reject the price control offer is made. Whilst RORE is another tool to use in looking at the issue of risk and reward there is a danger that taking an overall view in isolation misrepresents the more complicated basket of risks and incentives that make up the price control package.

Consistent with Ofgem's desire to stimulate companies to adopt less risk-averse business models, the allowance for cost of capital at DPCR5 must recognise the need for equity financing for network investment of national strategic importance. RORE thus provides another perspective in gauging risk faced by DNOs. However, given it is an "artificial" measure, its use is limited. We note that Ofgem takes pains to explain that RORE is not a "real-world" measure of actual return on shareholders' equity. The current figures also make several simplifying assumptions, for example the estimation of DNOs' current and future financing costs. This again highlights that it would be imprudent to place too much weight on this measure, for example by setting an ex-ante cap on overall outperformance.

It is not entirely clear from the document what lessons Ofgem believes it has learnt from RORE. However, in summary, we do not think it would be helpful to compare overall RORE with a view of what companies have delivered without considering the more complicated background of the risks borne by DNOs. We would potentially support the use of RORE as another piece of evidence to inform how individual caps and collars are set by comparing it to the levels of risk for each scheme, subject to an explicit recognition of its largely theoretical nature. Nevertheless, the starting point for scheme design should be an assessment of what DNOs are physically able to control and to achieve within the period, taken together with a view of factors beyond our control and a view of society's willingness to pay (implied or explicit).

Question 3: Have we identified appropriate measures to address our concerns and deliver a settlement that provides better rewards/penalties for highly performing/poorly performing companies?

Not entirely. Whilst Ofgem's view of the major drivers of network change and sources of uncertainty over the coming years is one that we share, it is possible to read the document and come away with the impression that DNOs plan to react in a way that provides too little, too late.

The reality is slightly more balanced:

- Central Networks is taking a positive and leading view of innovation, borne out by our track record in DPCR4. We were the first DNO to announce and commission an RPZ, and we have taken a leading role in joint industry work to develop a vision for the future of networks. We have included specific funding for ring-fenced innovation and engagement resource in our Forecast Business Plan Questionnaire (FBPQ).
- As Ofgem recognises, the current framework means that any rational commercial organisation would not decide to invest unconditionally in the sums needed to trial active network or demand management technologies or contracts on a real-world commercial basis. As well as facing opex cost pressures, companies simply do not have reassurance that they will get a return on their investment that makes the extra risk worth taking.

- This is changing, and we support Ofgem's proposals for innovation in the paper and recognition of the need for change. DNOs and Ofgem now need to work together to build these into workable schemes with a realistic assessment of what companies are able to propose now, and what detail has to be developed.
- Ofgem recognises that innovative projects may not succeed. Paragraph 1.13 in Appendix 15 suggests that customers' money is not "usefully employed" where this happens. This fails to recognise the benefits of the overall learning process for companies and society as a whole. Elsewhere (e.g. paragraph 2.4) the view is expressed that, if DNOs try hard enough they will be able to predict the future perfectly and "misjudging" what may actually happen is a sign of inefficiency that needs to be penalised. The overall view is that companies may be penalised if they don't take risks and then penalised again if they get it wrong. This appears not to recognise the risk-sharing nature of the agreement required between companies and Ofgem, as the representative of customers, wider society and Government.
- Innovation and development is a trial and error process and companies invest in the knowledge that not all projects will succeed. If Ofgem wants to encourage a less risk-averse attitude (which we believe is the right thing to do) the increased level of "business as usual" risk has to be recognised somewhere in the price control. We recognise that further work is needed to develop more detailed proposals. We have already submitted two papers to Ofgem on options and look forward to taking this further over the coming months.

This discernibly penal attitude towards companies is also seen in the proposals for losses. As we have said above, and bilaterally to Ofgem, the incentive as currently proposed fails to recognise the limited control DNOs will have over the losses measure in DPCR5 and will not encourage innovative thinking from DNOs about how to reduce losses in future. As a minimum, we would argue for caps and collars on the losses regime, although we think the proposed scheme to link income to the value of carbon saved on a scheme by scheme basis provides a better and more transparent incentive.

Question 4: Do you think our proposal to base DNOs' incentives for under/outperformance around their effective return on equity is appropriate?

Question 5: If you do, what range of return on equity do you think would represent a fair balance between customers' and shareholders' interests to reward increased efficiency, better service and innovation, whilst maintaining strong incentives for shareholders of any poorly performing DNOs to improve performance?

For the reasons stated above, RORE should only be used to provide another view of the relative risk and reward of individual incentive schemes, not as the starting point for setting caps and collars.

In our response to Chapter 4 we explain that an annual dialogue between companies about output delivery and material changes of information is needed to make sure that performance is judged objectively. This could also include a discussion about Ofgem's perceptions of performance against incentives and options for innovation, and would make the subsequent DPCR6 review more effective. Reserving judgment until the end

of the period, and providing no flexibility in output measures given their infancy would significantly increase regulatory risk and encourage risk-averse behaviour.

1.66. […] We would be interested to hear the views of DNOs and other interested parties regarding the overlaps between DPCR5 and RPI-X@20. In particular, we would be interested to understand whether parties may have any concerns regarding the overlaps between the projects or the best way to take account of these linkages.

The RPI-X at 20 review needs to make sure that issues that are not dealt with fully at DPCR5 (in particular enduring approaches for pensions and investment ahead of need) are picked up. We are concerned that "gaps" may arise where important policy issues are not dealt with.

Key areas for the RPI-X review to tackle include:

- Investment ahead of need.
- The longer term role of DNOs (as recognised in Ofgem's draft corporate strategy) and implications for wider market change.
- An enduring approach for pensions.
- The longer term sustainability of the RAV model.

Subject to specific comments in this document, the policy document presents a scope for DPCR5 that we broadly agree with. Ofgem and DNOs have limited resources and there is limited time remaining to reach agreement on the DPCR5 settlement. We would therefore encourage Ofgem not to transfer issues across from the RPI-X review to DPCR5 unless it becomes absolutely critical that a resolution is required for Ofgem to fulfil its statutory duties or companies to meet their licence obligations. We consider this to be highly unlikely.

Chapter 2

Environmental Issues

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?

2.1.1 Uncertainties and appropriate regulatory mechanisms

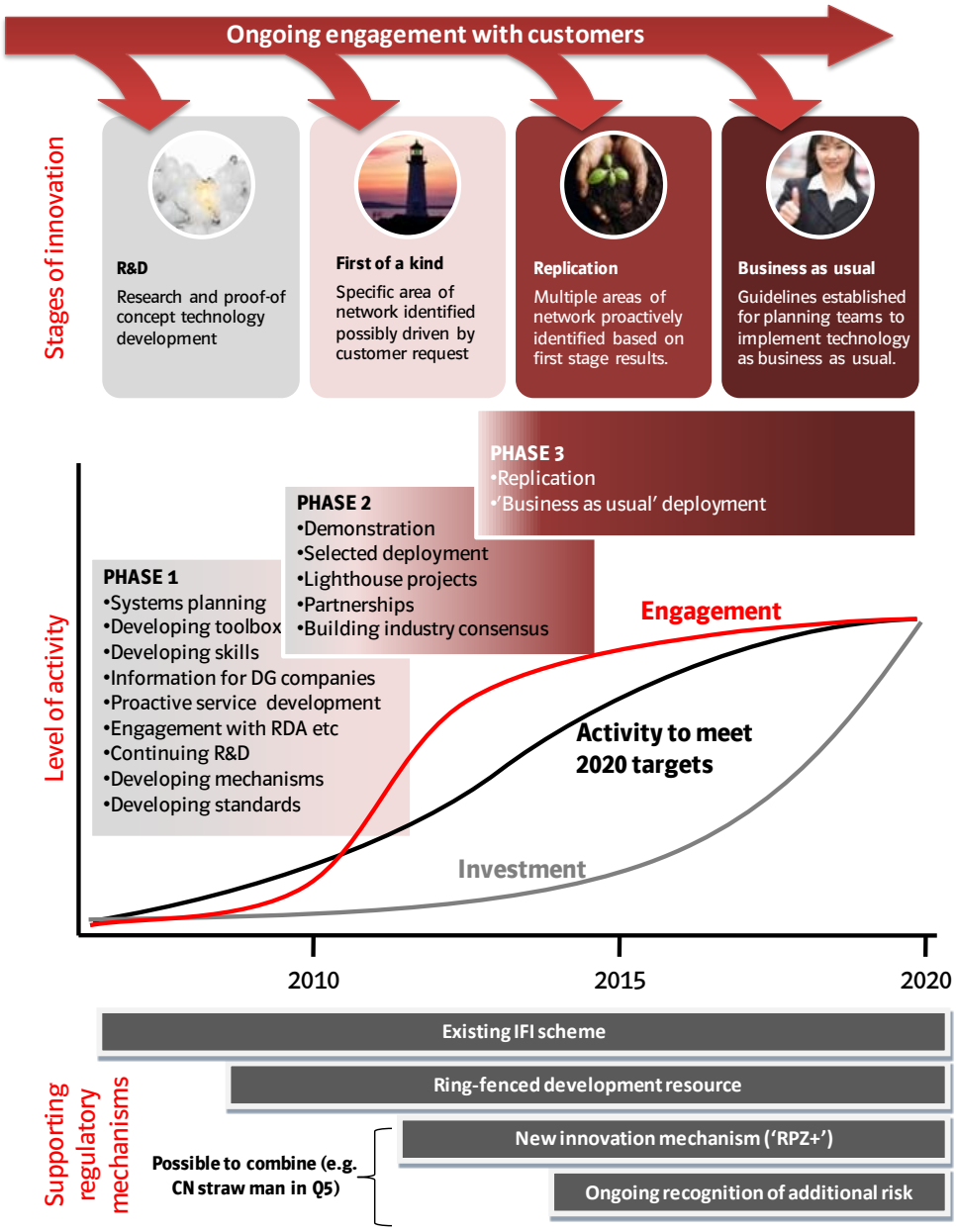
The recently introduced national policies relating to energy will certainly have implications for networks. These policies include UK commitment to EU 2020 renewable targets, planning targets for local energy for new developments, zero carbon homes, renewable heat strategy, energy efficiency, microgeneration, renewable energy feed-in tariffs, smart meters, electric vehicles and electricity storage, and we broadly agree with the associated uncertainties that Ofgem identifies.

There are key economic uncertainties around electricity demand and price as well as more behaviourally driven impacts arising from the engagement with smart metering and a growing environmental awareness, the development of distributed generation and the penetration of electric vehicles and heat-pump loads.

We believe it is helpful to consider three key stages in the development of the network solutions required to help support UK energy policy objectives:

- A concentrated period of planning and engagement, requiring resources that DNOs have until now been unable to justify commercially given the current focus on opex and lack of certainty of cost recovery under the current regulatory framework. Our DPCR5 business plan contains specific resources allocated for this task.
- The building of demonstration projects and key partnerships early in the DPCR5 period, supported by a modified RPZ scheme and the DG incentive.
- A rapid increase in the scale of distributed generation and smart network solutions moving to a rollout as 'business as usual', minimising the unit cost of application, but potentially adding to the levels of business risk within the network companies.

The approximate timing of this approach is illustrated by the diagram below, with the early period of engagement and development followed by the later increase in network investment.



We agree with the need for a regulatory framework that better supports innovation and flexibility, by providing the funding certainty needed for DNOs to implement these steps. These views are shared by Parliament. In its final report, the Business and Enterprise Committee recognised that "the UK's future energy mix will come from a more diverse range of sources, including local energy…" and that "the scale of investment required to install them is likely to be huge." We will be making a full contribution to the new Committee's recently announced enquiry into "The future of Britain's electricity networks", building on the themes in this document.

We highlighted in our Initial Consultation response that RPI-X regulation has very effectively encouraged DNOs to focus on core operational efficiency. However, the scale of activity envisaged, and the development and implementation of innovative approaches and technology will require the progressive introduction of new skills and resources. This growth needs to be actively stimulated by the financial 'ring fencing' of

the associated resources to both allow a process of incubation and to clearly signal the importance of the issue. We estimate the cost would be about 50p per customer, which is equivalent to less than 1% of our average annual domestic Distribution Use of System (DUoS) charge.

The key uncertainties are:

- **The resource requirements needed to work with stakeholders and deal with projects in an innovative, timely and transparent manner**

  This is a function of both volume and complexity, and also, for example includes work needed to develop contractual approaches to demand side management (including an intensive "sales pipeline" to identify, develop and filter potential energy projects).

- **The volumes, types, location of generation and demand**

  Very little of this is within DNOs' direct control. We are however actively working towards a common charging methodology, although the exact behaviour of generators in the face of locational price signals remains unclear. We are very supportive of providing tailored expert advice and access to internet based solutions to help our customers identify the best places to site their developments.

- **The time and cost required to develop a commercial framework**

  This would have to have to accommodate a number of potential interactions between DNOs, suppliers, customers and possibly Elexon and National Grid. These issues are not insurmountable and the majority of them have already been identified. We suggest that there are three regulatory mechanisms needed to move to a more proactive way of working by the end of DPCR5.

Support from the regulatory framework will enable DNOs to move to a more proactive way of working by the end of DPCR5. Our views on these mechanisms are discussed in more detail in the following answers. However, our main point is that the early stages of DPCR5 will need to be more focussed on engagement, development and deployment with widespread 'business as usual' use of new techniques unlikely to begin to happen until later in the period. Flexibility in the regulatory framework will be desirable, to handle an accelerating growth in demand for connections, necessitating a change in work programme.

2.1.2 The need for DNOS to 'change their way of working.'

We are surprised by Ofgem's suggestion that the DNOs are reluctant to embrace new ways of working. Central Networks is already engaging fully with innovation and are we are preparing ourselves for the future, as set out below.

We are innovating in DPCR4	• Central Networks was the first company to commission a registered power zone employing dynamic line ratings. • We are using innovative models for improving cost efficiency, customer service and delivery (lean working and risk-sharing partnerships with our external service providers).
We are working with	• We are working actively with developers of distributed energy projects and exploring new opportunities.

stakeholders	• We are working with our stakeholders and adopting broader measures of customer satisfaction ahead of DPCR5. • We are providing expertise to the West Midlands and East Midlands regions, our local authorities and collaborating with the public sector whenever possible, for example in the development of energy scenarios and solutions • We are identifying the need to undertake more intensive strategic planning for local networks and proactive engagement with developers prior to connection. • We are developing web based assessment tools for generation customers
We are preparing our networks …	• We are adopting a new method of assessing and measuring the need for and impact of reinforcement spend which will mean we actively take on a higher level of risk during DPCR5. • We are proposing some 'network ready' investment in an area of particularly abundant generation resource within our business plan. • We are proposing to explore the use of 20kV networks for the connection of generation • We are planning to reduce the use of tapered network design – partly to reduce losses, but also in recognition of new demand from electric vehicles and heat pumps. • We are planning to install communications cables with major network extensions, wherever appropriate, in readiness for deploying "Smart-Network" techniques. • We are anticipating changing design specifications to make space for new network facilities, and procure plant with communications ready specification where appropriate.
… and our systems for the future	• We are implementing world class innovative automatic sequence switching schemes • We are planning for the assessment of new control system functions to support network analysis • We are actively working to determine smart metering costs and benefits and are contributing to the development of a smart meter specification

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?

We are very supportive of Ofgem's desire to improve the provision of information to all DG developers, though we have some concerns over the extent of the information

provided automatically due to the accuracy of data and interaction between competing projects.

Our own stakeholder engagement highlighted that different types of developer have different requirements and that the existing Long Term Development Statement (LTDS) in general only met the needs of larger, technically strong developers. Many smaller developers expressed a preference for a reliable and personal DNO service that would provide connections advice, budget prices and quotations in a timely way. The engagement resource we propose in our answer to Question 1 would form part of this proactive solution. The desire for a proactive "engagement" team is also echoed by wider stakeholders, in particular local authorities, to help with development of local strategic and emergency plans. However, we believe that a simple to use, internet based system to give information about our network and any estimated connection costs would be appropriate for domestic customers.

DNOs will need to agree with Ofgem the details and timescales for implementation of replacement, or additional documents or systems. These will need to take into account both stakeholder expectation and the amount of development work required. The companies should be allowed to recover the efficient costs of development, implementation and ongoing service provision. These implementation costs have not been included in our base case as the precise requirements have yet to be determined. We would expect any requirements for improving information to be funded adequately through the final settlement via an agreed allowance.

There is a concern about the open publication of network data from a security perspective, and we therefore suggest a simple system of registration for developers and domestic customers requiring data.

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?

The treatment of distributed generation connected prior to April 2005 is a controversial issue which has been argued over in various public forums over several years. Central Networks' interests lie in the effectiveness and efficiency of the network and the corresponding charging arrangements.

From an effectiveness perspective, if some form of locational signal is to be provided to EHV connected generators in future, it would seem desirable for all generators to be exposed to these signals.

From an efficiency perspective however, the transition to charging all DG seems likely to be difficult and costly, especially if it involves some form of rebate against historic 'deep' connection charges.

Given that some generation was connected many years ago, it may be difficult for DNOs to justify proactive payment of a connection charge rebate, to generators. If some form of rebate is thought appropriate, a more appropriate alternative may be to put the burden of proof in respect of deep charges historically paid onto generators, with a default assumption that none were paid. As demonstrated by data supplied by the DNOs to the (then) Implementation Steering Group (ISG), this assumption is likely to prove correct in the vast majority of cases.

Although we can understand Ofgem's preference to have locational pricing in place before uniting generation and demand revenue 'pots', having a united revenue stream is a pre-requisite to transferring benefits from demand customers to generators. Without a single pot, the benefits of the common methodology that DNOs are working on for HV and LV generation customers (and ultimately, also, EHV) will not be realised. Combination of the pots is an essential piece of work that can and should be done as early as possible in the DPCR5 process.

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

The volumes of DG connected to date during DPCR4 are not sufficient to determine conclusively whether the DPCR4 DG incentive has been effective. Continuation of a similar scheme into DPCR5 is therefore appropriate. However, broader support is also needed since the current formula provides an incentive for DNOs to reduce the cost of generation connection but does not encourage proactive engagement, particularly where there is no certainty of the scheme going ahead.

The DPCR5 incentive (or the wider package of innovation incentives) therefore has to recognise that low-cost connection of generation is just one element that is required in the provision of an effective and sustainable low carbon energy facilitation package. Other elements include proactive engagement and customer service, development and management of commercial agreements as well as provision of the connections themselves. Ofgem must make sure that as well as the DG incentive encouraging efficient, project specific, capital costs of connection, the wider development of the skilled resources needed to meet wider future networks aspirations can also be efficiently funded.

It is important that the strength of the DG incentive is sufficient to manage a potential increase in connection volumes beyond that which DNOs have submitted in their plans. Central Networks has prudently submitted a base case based on current trends. These could change significantly with accelerated changes in policy (e.g. the impact of feed in tariffs or reduced connection administration requirements – an increase of the G83 connection certificate threshold for example). In setting the incentive strength Ofgem will need to bear in mind that costs to date reflect that the schemes that have taken place have been the easiest and cheapest to implement – this "cherry picking" behaviour having been driven in part by the DG charging mechanism. Reducing the level of incentive may therefore make it harder to achieve a stretching set of 2020 carbon targets.

Embedded transmission will have the same impact on the distribution network as a generator located at the same network node, and therefore it would seem that the same efficiency of connection is desirable. This would be encouraged by deeming embedded transmission as relevant DG for the purposes of the DG incentive.

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?

We agree with Ofgem's recognition that the present risk imbalance between opex and capex has a significant influence on a DNO's approach to innovative solutions. Addressing this and providing a new innovation incentive will be an important step in seeking to set out a regulatory framework for flexible networks to support a low carbon future.

Ofgem not unreasonably suggests that customers should not pay for the DNOs' failure to plan for the future, but it must be recognised that a perfect plan will never be possible. Furthermore, the future is much less certain than in previous price controls and additional flexibility will introduce additional costs and risks. We welcome the view that solutions which increase opex can be efficient and should not be penalised by the price control.

We share the broad consensus that the Innovation Funding Incentive (IFI) mechanism is working as intended. It has encouraged much research and development (R&D) and has enabled universities to grow specialised resource which will be invaluable in supporting future innovation and change. We therefore support the proposal to retain the IFI as an R&D incentive.

We have already submitted two separate papers to Ofgem on the subject of wider innovation incentives. These described:

- Aspects of the current RPZ scheme that need to be changed – recognising in particular that the current methodology is only really viable for schemes at the highest voltages, is limited in scope and does not support replication.
- A broader 'straw man' proposal for a system mirroring the commercial drivers created by patents, providing an incentive for companies to bear some up front development cost and risk in exchange for a higher reward, in the form of a cost of capital premium for specific projects, in recognition of the higher level of risk associated with innovative approaches. This is attached in Appendix A.

We support Ofgem's desire to improve incentives in this area. Of the three mechanisms put forward as an innovation incentive by Ofgem, option 2, "in-period" funding, would seem to us to have most merits, and most closely resembles what we have already suggested, **with the important exception that the policy proposals do not seem to provide any support for increased "business as usual" risk – i.e. phase 3 in the diagram included as part of our response to Question 1.** Option 1, project funding based on the FBPQ, would seem very restrictive in that it only covers opportunities that are visible to the DNOs in advance of the Final Proposals document (in reality perhaps the next five months). As we have explained above, DNOs have to date not had sufficient commercial security of funding recovery for the material investment required to create 'leads', pursue them (accepting that a proportion is likely fail at each successive stage) and develop detailed workable solutions. Furthermore, the uncertainties identified in Appendix 6 of the Policy Paper will not be resolved in that timescale. Option 3, ex-post assessment of outcomes, increases uncertainty for DNOs and the risk level disproportionately to shareholders and is unlikely to stimulate commercial decisions to increase risk exposure. Option 2 shares risk between customers and shareholders, allows DNOs to table projects in response to developments throughout the price control

period, and Ofgem's role in project approval reduces regulatory risk. Our 'straw man' in Appendix A is a suggestion for how this approach may be worked out in practice, and we would be happy to develop this further.

What is important, however, is that a clear structure is established ex-ante so that DNOs can have certainty over incentive income, and therefore the level of risk to which they will be exposed. This requires an agreed transparent funding mechanism that is flexible enough able to cope with a potentially high volume of projects. In the case of our 'straw man', the administrative burden on Ofgem could be limited to type approval and auditing.

In order to meet the UK commitment to EU 2020 renewable targets all DNOs will to have to become more innovative. We do not support a common fund and believe a fixed ex-ante allowance may be unduly restrictive. A totally competitive approach between DNOs would unnecessarily delay network projects that fail to get funding – with a consequential impact on the time and cost to connect embedded energy schemes.

We look forward to further discussions on the innovation incentive mechanism.

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

Transmission exit charges are based on the specific assets required at the boundary to supply demand to the DNOs. Once the assets are installed they are long lived, almost always over forty years. DNOs have a limited influence on either peak demand or volume of units distributed, and such influence is in any case small when compared to wider factors such as price or economic cycles.

If a reduction in demand were to be achieved it is unlikely that assets of a smaller capacity would be installed at the boundary, unless this coincided with end of life of the transmission assets. In any event, NGET termination charges are likely to neutralise the benefit of any asset reductions that could be achieved in this way. Many boundary assets are at or near the end of their economic life, and we would expect unavoidable increases in exit charges simply as a result of asset renewal. There seems to be limited scope for DNOs to manage these charges in a meaningful way. Ultimately, customers are protected from excessive exit charge costs via the regulation of transmission charges.

We are keen to deploy demand side measures where appropriate, but we do recognise that such an approach could be relatively short lived, and that depending on many of the uncertainties we face, it may be possible to defer reinforcement but not avoid it altogether. The long lead times associated with investment in the transmission network would mean that, in the event the demand side measures prove insufficient, customers would be exposed to a lower standard of security of supply. This risk would seem large when compared to the value to customers of any savings in exit charges as the result of an incentive.

Ofgem suggest that it may be possible for DNOs to agree innovative deals with the transmission company. We already conduct negotiations with National Grid about the scope of work to minimise the assets required. We would welcome a wider discussion on the charging methodology between the DNOs and the transmission companies, but note that all parties will need to share a willingness to innovate for these discussions to be successful

In view of these factors we believe that the existing pass through arrangement should be retained.

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?

Central Networks has consistently operated two of the lowest loss distribution networks in the UK, and has fed-through loss reductions as lower line loss factors that have benefited suppliers and, ultimately, customers. During the DR4 period adjusted losses in Central Networks East have been below target and in Central Networks West they have been above target, and we have received rewards and penalties accordingly.

The precise degree to which these over and under performances can be attributed to network developments, as opposed to other factors, is unknown, and probably unknowable. It is possible to make an assessment of the likely impact of particular network loss reduction measures, and we and others have proposed this as the potential basis for an alternative, *quasi output* incentive scheme. This would provide consistency between DNO action and reward. We believe a *quasi output* scheme would drive DNOs to reduce their carbon footprint by changing their network policies and practices. This would deliver greater transparency and would provide Ofgem and other stakeholders with demonstrable evidence of actions to reduce carbon footprint, and the reassurance that any rewards had been 'earned'.

In practice, the influence DNOs are likely to have on *technical* losses (i.e. carbon) in the short term is relatively low when measured using the current output approach. Our assessment suggests that using low loss transformers and oversized cables as part of our DPCR5 program of work would lead to a losses reduction of around 0.02% per year (some 13-14GWh, equivalent to about 6,000 tonnes of CO_2). This still represents a material reduction in absolute terms, but is small relative to the amount of error and volatility in the overall output measure. We believe that any robust incentive scheme should take account of the relatively low levels of loss reductions that could realistically be made in any five year period.

Ofgem's preference for an output incentive using settlements data does not reflect the relative magnitude of the carbon reductions that are realistically possible, and does not provide a clear link between DNO action and reward. Volatility and error in settlement data could mean that a DNO that has taken effective action to reduce losses is actually penalised because settlement data suggests, erroneously, that losses have increased (or vice versa). While Ofgem is correct to point out that in theory such a DNO would still receive the marginal benefit of their action, clearly a regime where effective positive action can result in heavy penalties is not robust.

It should be pointed out that settlement volatility in the Central Networks area can cause units distributed (and therefore losses) to swing by over 500GWh per year between initial settlement and final reconciliation. Ofgem notes, in paragraph 2.87 of the consultation, that such volatility is decreasing. However, from our experience, this is simply not the case and it would be useful to understand Ofgem's basis for such an assertion. The table below shows how non-half hourly units distributed have changed between settlement runs for Central Networks East, for the most recent five years for which data has reached the final reconciliation (RF) stage. Since Central Networks West was only acquired in 2004, we do not have a full set of equivalent data for the West, but

for the years 2005/06 and 2006/07 the movements between SF and RF settlement runs were minus 68GWh and minus 198GWh, respectively:

Table: Central Networks East: Non-half hourly Settlement Data

	R1 - SF GWh	R2 - R1 GWh	R3 - R2 GWh	RF - R3 GWh	Total Movement RF - SF
2002/3	59	62	-11	33	143
2003/4	61	77	3	61	202
2004/5	49	87	4	35	174
2005/6	-14	-65	-66	-57	-202
2006/7	-41	-71	-92	-129	-332

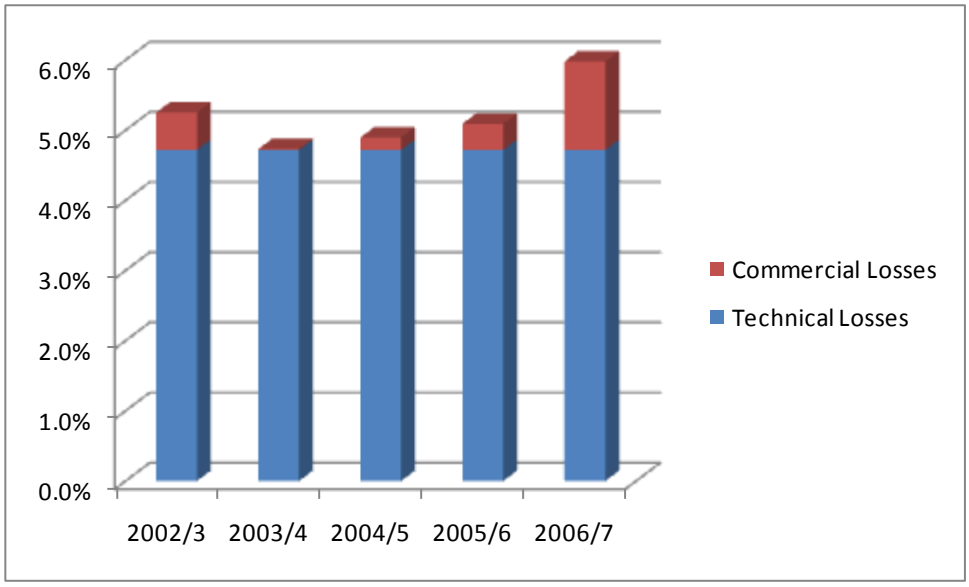
The data above shows two things very clearly. Firstly, settlement volatility is not reducing as Ofgem claim, and secondly, the scale of volatility vastly outweighs any direct impact a DNO can have on losses, whether technical or commercial. When translated into the impact on DNOs' allowed revenues, assuming a losses value of 10p per unit, such huge volatility as that for 2006/07 in our East area equates to allowed revenue reducing by £33m (more than10%) between initial and final settlement data. Such movements in allowed revenues would inevitably lead to huge tariff swings year-on year.

The above analysis only looks at settlement volatility. There is also settlement error, which could be plus or minus 300GWh. Settlement error will form a large element of commercial losses, and in the consultation paper Ofgem use the example of EDF Energy to suggest that a DNO, when focused, can reduce commercial losses – presumably by impacting settlement error. We would like to make three important points on this.

- Firstly, DNOs have no impact on the majority of settlement error, as can be seen from the BSC audit report for 2007/08, where only 35 of the outstanding 302 issues relate to either the LDSO or UMSO.
- Secondly, we believe that where DNOs can impact on settlement error, it is of course limited to the extent that they have not been focused on preventing errors in the past.
- Thirdly, it is important to note that error correction can just as easily result in an increase in losses, as a decrease in losses. Error correction should be encouraged regardless of its impact on settlement data, and therefore we would question the logic of a losses incentive being the place to encourage error correction.

In 2008 Central Networks commissioned E.ON Engineering to undertake an extensive network study to model technical losses on our networks. The study concluded that technical losses on our network were 4.7 % in CNE and 4.2% in CNW (+/- 15% margin of error). The chart below uses the results of this study to show the makeup of total losses on our East network using settlement data as received for the last 5 years which have reached final reconciliation.

Chart: Central Networks East: Technical and Commercial Losses



The graph clearly shows that the scale of commercial losses can be very significant, representing 26.7% of total losses in 2006/07, but more notably the variation in commercial losses year on year is also significant and represented only 0.2% of total losses in 2003/04. This provides a range in total losses of 26.5% which translates into approximately 370 GWh or £37m assuming a losses value of 10p per unit. We are of the opinion that the amount of error contained in settlement data, the majority of which the DNOs have neither created or have any control over, severely challenges the feasibility of an output incentive for losses. More importantly the volatility of such error confirms that DNOs will not be remunerated for the actions they take but simply by the large natural swings in the error contained in settlement.

Volatility and error in the data used to determine network losses – calculated as the difference between two very large numbers – is a serious problem in determining losses. Measurement of the volumes of units flowing into our networks is, in general, highly precise and reliable. However, at the other end of the network we have nearly five million meters, the vast majority of which are read quite infrequently. Add to this the known problems of unmetered supplies, meter fraud, other illegal extraction, profiling error, etc. and the detailed picture we have of units flowing out of the networks is unstable and largely unmanageable.

In addition to the 'normal' errors, during DPCR5 we will see the transitional effects of smart metering roll-out, which will crystallize discrepancies between the estimated annual consumption used in NHH settlement and the actual advances from long-unread meters or vacant sites; the impact on losses of increasing amounts of micro generation; and increases in network load factors driven by our asset utilisation policies (temporarily offset by the current dramatic slow-down in the economy). There may potentially also be impacts during the DPCR5 period from the wider installation of energy efficient electric heat pump systems, and increased adoption of rechargeable electric vehicles. It is not clear when these changes will bite, or indeed whether their overall impact on losses will be positive or negative. It is, however, clear that we have the prospect of a highly volatile and unpredictable period, for which it will be very difficult to set credible targets for losses based on the current output mechanism. Continuation of the current incentive scheme in such circumstances could therefore be seen as bad regulation, given that Ofgem would be penalising DNOs based on a

measure that companies have no real control over and which exogenous factors are making worse. Ultimately, this measure cannot be demonstrated to have reduced technical network losses (i.e. carbon emissions) in DPCR4. Likewise, there is no evidence that continuation of this measure would reduce carbon emissions in DPCR5.

We understand Ofgem's preference for a simple target-based incentive, but see significant and unpredictable risks in this approach, for both customers and the DNOs. There will be the real prospect of DNOs either gaining un-earned rewards or suffering undeserved penalties through a simple loss incentive in DPCR5.

We are interested by WPD's proposal to install additional network metering to better estimate losses but, as set out in our letter of 18 November 2008, do not think that it would be cost effective to deploy this approach across the whole of our network. Achieving installations of adequate accuracy and coverage in timescales significantly shorter than a national programme will be time consuming and expensive. It will also be resource intensive, diverting skilled labour away from our planned and reactive work, affecting customer service. In the longer term, once the smart metering roll-out is complete, we will be much better positioned to accurately measure network outflows, and therefore to properly calculate losses over the whole network. For example, this will include the impact of LV losses (estimated at 25 to 30% of total technical losses) and theft, which would not be covered by substation installations. Although the transition period will be volatile, we expect reported losses to become very much more stable and reliable once smart metering is in place. However, one use of substation metering that does seem to be sensible would be to use it in limited local trials to investigate and confirm the benefits of loss-reduction projects on the network, or to further investigate the impact of settlements data as in the WPD trial.

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

We support the principle that DNOs should report their business carbon footprint. It is however imperative that the costs of reporting are proportionate to the benefits derived and consistent with other reporting programmes (e.g. CRC) to avoid duplication.

There is a trade off between the level of detail of emissions recorded, the cost of data collection and the benefit of achieving a particular degree of accuracy. We are concerned that we will be required to impose disproportionate administrative burdens on our suppliers and their contractors for no obvious benefit. We are encouraged that Ofgem has noted this and look forward to discussing the detailed methodology to ensure that this is the case.

The proposal to record SF6 in the Business Carbon Footprint (BCF) reporting rather than establish a separate incentive is appropriate, as are the proposed headings against which emissions should be reported.

Ofgem has correctly identified the factors which need to be taken into account before publishing a league table of BCF performance. It will take a number of years of reporting to establish a level of consistency between DNOs. When the baseline is established it will be important to recognise any emission reduction measures taken by companies before the start of DPCR5. Ofgem should ensure that both these aspects are satisfactorily agreed with the DNOs before starting publication of the league table.

It should be noted that the *quasi-output* carbon/losses incentive that we proposed was intended to provide an incentive on DNOs to reduce their Business Carbon Footprint. Coupled with appropriate reporting, we believe this would drive DNOs to place greater focus on this important issue.

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?

We welcome Ofgem's proposal to raise the voltage caps from the existing level. However the caps should be increased in real terms (i.e. taking into account the effect of real input price increases).

The values proposed in Appendix 6 of the Policy Paper would appear to update the original caps, which were based on 2002/03 money, by an amount close to inflation. In practise this is unlikely to have the desired effect of increasing the number of undergrounding proposals which fall below the cap. Our understanding of the view expressed in paragraph 1.82 of Appendix 6 is that the 20% should be applied in real terms, i.e. over and above inflation. More specifically, the caps should be as follows:

Table: AONB voltage price caps per km.

	2002/03 price caps per km in DR4 settlement	RPI index to 2007/08	2002/03 price indexed by RPI to 2007/08	Ofgem proposal, Policy Document, 2007/08 prices	20% increase, 2007/08 prices
LV	£65	1.18	£76	£78	£92
HV	£85	1.18	£100	£102	£120
EHV	£350	1.18	£411	£420	£494

The use of a single cap may give DNOs the option to carry out one or two 'flagship' undergrounding schemes but it is unclear how best to balance the value to stakeholders of this approach when compared to the existing approach.

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

Ofgem's proposal that DNOs continue to operate in accordance with the risk-based Operating Code developed jointly by the Environment Agency and the Energy Networks Association is an appropriate approach to managing fluid filled cables.

Chapter 3

Customers

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

In general we agree that the existing and proposed arrangements will deliver the levels of service customers expect. However there are some adjustments we believe would improve the proposed arrangements. The details of these are given in the responses to the other questions in this chapter.

We welcome the proposal to consider other customer interactions within a broader customer service measure as we feel this will give a more rounded view. However requiring DNOs to implement best practice as a licence condition could limit DNOs abilities to tailor their services to meet the needs of their customers. This would also result in potentially onerous annual licence modifications and could stifle innovation as some companies are forced to play catch up rather than investing in new initiatives.

Given that DNOs have shown a general willingness to adopt best practice measures then the imposition of a licence condition appears unnecessary.

An area where we would suggest an addition to the proposed arrangements is that of ongoing stakeholder management. We believe that this is an important feature of customer service which is distinct from the scope of the Customer Service Reward and does not logically sit within the proposed overall customer satisfaction measure. Further details are given in our response to question 3.

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

We believe that the overall level of exposure should be increased, to accommodate the increased scope of the customer satisfaction measure and a new incentive for stakeholder management.

However, we believe that the increase in the incentive exposure in these areas will not result in a disproportionate imbalance between the incentives, as we believe significantly greater financial emphasis should still be attributed to Customer Minutes Lost (CMLs) and Customer Interruptions (CIs) reflecting customers' priorities. The overall exposure for the Interruptions incentives should remain at 3% of total revenue.

3.2.1 Changes in Incentive Exposure

We suggest that, whilst the new overall customer satisfaction measure runs in parallel with the existing telephony measure, the overall penalty and reward is split between the two items. When the existing telephony incentive is subsequently incorporated into the customer satisfaction measure the financial rewards and penalties can also be combined at a level similar to the current exposure of the existing telephony incentive.

We also believe that, while the Customer Service Reward is set at around the right level, a new incentive should be introduced in the area of continuing stakeholder engagement, which should have a level of reward and penalty of similar magnitude to the overall customer satisfaction incentive.

3.2.2 Split between incentive areas

In terms of the split between various incentive areas;

- Network Performance is the key concern of our customers therefore we believe this area should have the largest share of the exposure.
- The Network Connections activity will now be more heavily incentivised via its inclusion in the overall customer satisfaction measure and exposure to both Guaranteed Standards and the new Complaints Handling Standards Licence Conditions. This seems to better reflect customer priorities, particularly for those customers whose connections will not be targeted by competition.

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

We believe that the customer service incentive framework should have three distinct elements to it, namely,

1. Broad customer satisfaction measure
2. Customer Service Reward
3. Stakeholder management incentive

We believe these elements to be distinct in the attributes that they relate to and also to be suited to different methods of evaluation. We believe that, as the broad customer satisfaction measure and our proposed stakeholder management incentive relate to DNOs performance now, this is best measured by surveys of the customer base and stakeholders retrospectively. However as the Customer Service Reward focuses on innovation and ideas that have only recently been introduced, it is fair to continue to assess this using a panel of judges. We believe that stakeholder management should be considered separately from the customer service reward and the broad customer satisfaction measure. Stakeholder management is the "glue" that binds other elements of customer service, being the key to delivering innovations that customers really value and also to their successful implementation, leading to long term overall customer satisfaction.

3.3.1. Broad Customer Satisfaction Measure

We support the intention to develop a broad measure of customer satisfaction which reflects upon a wider range of customer interactions than the current telephony survey. We have already implemented such a measure for our connections customers which gives us a more rounded view of how our customers feel about our service.

We have outlined in Appendix B1 the interactions that DNOs have with their customers together with consideration of the practical issues that would be raised by including them in the broader customer satisfaction measure.

We believe that infrequent interactions will need to be excluded as there will be issues with getting a suitable sample size when trying to measure customer satisfaction. Similarly we should put greater emphasis on those transactions which are of highest importance to the customer.

Therefore we believe the items that should be included in a wider customer satisfaction measure are

1. No supply calls attended by call takers
2. No supply calls attended by messaging service
3. Planned interruption notifications
4. General enquiries (subject to a suitable method to gather customer data)
5. Connections enquiries, estimates and delivery.

3.3.1.1 Consistency of Measurement

This measure relies on comparability of the data between DNOs which we believe can only be achieved by the DNOs being surveyed by the same survey company. We believe this would also cost less than each DNO contracting with different survey companies. A single survey company should be able to gain economies of scale in setting up and administering the survey compared to the cost of up to seven companies doing this independently. In terms of how this is organised and contracted, then it would make sense to use a central body such as the ENA or Ofgem to provide a link between the survey company and the DNOs. With a view to cost, it may be likely that Ofgem, as the initial customer of the resulting data, is best placed to ensure that the cost of administering a survey represents value for money for customers. If DNOs are to contract with the survey company themselves then this additional cost needs to be reflected in DNOs allowances.

To ensure that all DNOs have the same understanding of what these interactions include, we agree with Ofgem's proposal in our December bilateral meeting to include explicit definitions in the revised Regulatory Instructions and Guidance (RIGs) as there is certainly the potential for enquiries and complaints to be interpreted differently.

3.3.1.2 Weighting of Elements within the Overall Customer Satisfaction Score

Whilst the customer satisfaction measure will result in one overall score, it would be useful for the information about performance in each area that is measured to be available to the DNOs so that they can identify and improve on any areas of weakness. The weightings applied to the different elements within the overall measure will also be an important factor and should reflect both the importance to the customer and the

frequency of each interaction. The importance to the customer of these interactions can not be calculated directly from the willingness to pay research. In our evaluation consideration has been given to the urgency of the customer's situation and whether alternative options are available to them. It would be useful to confirm with all the DNOs whether they agree with our evaluation of these in the table in Appendix B1 and customer representatives should also be involved in validating the weightings. Our initial thoughts for the relative weightings of these items within an overall score are given below.

Table 1 – Proposed Relative Weightings within the Overall Customer Satisfaction Measure

Item	Comment	Relative Weighting
No supply calls attended by call takers. Plus call backs relating to no supply calls.	This needs a high weighting as this is of highest importance to the customer and occurs frequently. As the call takers are providing a more tailored and individual response than the messaging service, the customer expects more from it.	4
Planned interruption notifications	This is high importance to the customer as it involves a loss of supply and is another item that DNOs perform frequently. This is weighted lower as it has less urgency than unplanned outages.	3
Connections enquiries, estimates and delivery	These interactions are relatively low volume but can have a high importance to the customers involved.	2
No supply calls attended by messaging service	While annual call volumes are high these are typically concentrated in storm periods. The customers receiving information from a messaging service may be able to speak to a call taker if they need further information and this back up option reduces the	2
General enquiries	These enquiries are often of lower priority to the customer than a supply interruption and account for a lower proportion of the customer interactions.	1

3.3.1.3 Use of Net Promoter Score / Advocacy approach

We believe that the introduction of a customer advocacy measure can be used successfully as a means of measuring engagement with our customers and getting direct feedback. Net Promoter Scores, in their purist form, rely on asking customers whether they would recommend a particular company or service to a friend. Regulatory restrictions mean that there is a difficulty around whether Central Networks, and other DNOs, can explicitly ask customers this question given that distribution is a monopoly activity. The common ownership of some DNOs and retail companies, may lead to business separation issues and also increased customer confusion.

We currently use a Net Promoter Score to measure customer satisfaction with our provision of new connections, which is appropriate as customers have some degree of choice in their connections provider.

We also use a method to generate an advocacy score from the existing telephony survey results which is detailed in Appendix B2. This technique could be applied to each area of customer interaction with their DNO to produce an overall customer advocacy measure/score reflecting a customer's overall level of satisfaction.

If a broader customer advocacy approach were to be introduced, we feel that any lead-up question(s) would need to be carefully phrased, due to the issues outlined above that restrict our ability to explicitly ask whether the customer would recommend a DNO. Moreover, we also feel that asking the question "Overall, how satisfied were you with Central Networks?" would not be suitable, for example. A customer who has experienced the inconvenience of a power cut may be unlikely to state they were satisfied with the DNO, regardless of the service they received, since their preference would be to have not needed to interact with the DNO at all. As an initial reflection, something phrased along the lines of "Following your phone call / enquiry / planned interruption notification / connection estimate etc. , what is your lasting impression of dealing with Central Networks?" may be more suitable, with the exact text tailored to the interaction the customer has had.

3.3.1.4 Acknowledging improvement.

We believe that some historical events, such as the extensive storm conditions in 2002 in Central Networks West, would continue to colour customer's opinions and satisfaction scores. Historical and demographic factors such as this may therefore make it very hard for some DNOs to ever reach the top of a league table. We believe that a significant improvement in customer satisfaction should also be recognised so long as the improved position is above a threshold level.

3.3.1.5 Interim modifications to the telephony incentive

We acknowledge the intention to eventually develop the overall customer service measure to an extent where the separate telephony incentive is not required. In the interim period we agree that reducing the number of attributes measured as proposed would not skew the results unduly.

3.3.1.6 Streamlining the measured attributes

Ofgem's suggested metric for combining the scores together gives equal weight to the remaining three factors of politeness, accuracy and speed. There is a need to avoid adopting measures, such as directly measured attributes for speed of call answering, that would incentivise DNOs to switch to using call messaging in preference to call handlers as this may not be considered to be good for customer service.

3.3.1.7 Calculating the score

Unsuccessful calls where the call has been terminated by the DNO would be frustrating to the customer and should be factored into the telephony score. However it should be remembered that in some cases customers themselves terminate calls if their power is restored while they were waiting for their call to be answered. If the measurement of unsuccessful calls can differentiate between calls abandoned by the customer from the calls terminated due to queue flushing etc. then this would be reasonable. If not then it may be prudent to reduce the weighting given to unsuccessful calls.

It should also be determined whether the calls terminated by the DNO were an inherent feature of the telephony system used or the result of operating practices. The inclusion of the term for unsuccessful calls would only seem fair if we believe DNOs are able to make swift improvements to this number, otherwise we are penalising the DNOs for the technology they currently have. Given that the telephony incentive is intended to be short lived, this may not provide the correct framework to drive improvement.

3.3.2 Customer Service Reward

The policy paper outlines a different role for the Customer Service Reward than was previously held by the Discretionary Reward which it replaces.

3.3.2.1 Aspects of Customer Service to be Covered

We agree that environmental issues should not be addressed through the Customer Service Reward scheme. However, we also believe that ongoing stakeholder engagement is a significant activity for all DNOs and that it also warrants a separate incentive (see below) rather than being an item within the Customer Service Reward.

We believe that the service to worst served customers should be improved, but that while customers would like improved communications ultimately their preference is for DNOs to make targeted network improvements. Therefore the regulatory framework is correct to incentivise communication with worst served customers, so long as this is not disproportionate to the way in which it enables DNOs to improve their networks.

3.3.2.2 Breadth of Category Definitions

Ofgem's suggested categories for the Customer Service Reward are

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

Both these categories have narrower definitions than those which were previously judged, e.g. wider communications, corporate social responsibility. This narrower focus can be interpreted as a positive reflection on the scheme, with the focus on niche areas suggesting high levels of progress and general satisfaction.

3.3.2.3 Potential Problems

However there may be problems resulting from adopting narrowly defined categories.

Firstly, DNOs will vary in the proportion of customers that they have in each category. As the number of worst served or electricity only customers in a DNO may affect the viability of improvement schemes that DNOs can implement, then this could make it hard for all DNOs to compete equally in these narrow categories compared to a more general category.

Secondly, there may be a risk that this encourages too narrow a focus by DNOs at the expense of the bigger picture. The broader categories defined previously encouraged DNOs to take a more holistic approach and this should be retained.

3.3.2.4 Suggested Solutions

One way of overcoming this could be to include a higher number of narrowly defined areas such that the chances of bias to any particular DNO are reduced. For example another area for evaluation could be performance of DNOs during exceptional events.

Another option would be to include a mix of broadly defined and narrowly defined categories together in the award scheme, such that focus can be applied to specific areas but DNOs are still incentivised to consider the bigger picture.

3.3.2.5 Embedding Best Practice

We oppose creating requirements in licence conditions for best practise as this restricts DNOs' abilities to meet their customers needs in the ways they feel are best. In some cases best practise can rely on third party co-operation to work (e.g. doorstop crime initiative). Given the high level of adoption of best practice items that has occurred without any compulsion within licence conditions there is no demonstrable need to include a licence condition to ensure DNOs consider the best practice. Such a condition leads to the potential minefield of defining what it means to "consider" something appropriately without restricting DNOs' flexibility and freedom. Ultimately the DNOs' efforts to meet the needs of their customers should be reflected in the overall customer satisfaction score and thus it should be apparent whether those DNOs who do not adopt best practice provide lower levels of customer satisfaction than those who do.

3.3.3 Ongoing Stakeholder Engagement Incentive

3.3.3.1 Need for Separate Incentive

We believe that effective stakeholder engagement is key to ensuring that, amongst other things, beneficial customer service innovations are generated and that these have the optimum impact when implemented by providing informed feedback loops. As shown in our Appendix B1, in addition to the high number of direct customer interactions, DNOs also devote considerable time and effort in liaising with representative bodies. Therefore we believe that DNOs' ongoing stakeholder engagement should be incentivised.

We do not feel that this fits particularly well within the overall customer satisfaction measure. Typically, these stakeholders have a role as representatives of customer groups which is different to the other elements in the satisfaction measure where customers are questioned about their satisfaction directly.

Similarly, we believe that ongoing stakeholder engagement does not sit within the Customer Service Reward framework. Whilst the customer service reward tends to focus on the innovations in customer service, we believe that monitoring how satisfied stakeholders are with their ongoing engagement with DNOs covers all the other elements such as how well the innovations were researched and targeted, how feedback was taken into account, how they were reviewed in practice etc.

3.3.3.2 Incentive Scope and Operation

This should measure how satisfied DNOs' stakeholders are with their DNO engagement and could cover aspects such as whether they believe their DNO has provided them with :

- the correct level of contact, to maintain an effective working relationship, feedback loops for new innovations etc.;
- sufficient information about the DNO and its future plans to understand its likely impact on the stakeholder;
- sufficient opportunity to influence the DNOs' plans and practices.

DNOs will not liaise with exactly the same set of stakeholders but there is likely to be a high degree of overlap between DNOs which would enable a fair comparison to be made.

To get as accurate an assessment as possible, all the stakeholders that a DNO engages with should be included in their assessment which may require some provision of information by the DNOs as to the people they regularly contact within each organisation.

We believe the reward for this incentive should be financially similar in scale to the broader customer service measure but that penalties are not appropriate. DNOs eligible for the reward could be determined in a similar way to the current operation of the telephony incentive, such that DNOs with average scores over a year above a threshold would be eligible. If a DNO failed to reach that threshold but had demonstrated significant improvement then rewards may also be applicable subject to a high enough final position being attained.

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

We broadly support the approach put forward for connections.

3.4.1 Market Segmentation

We believe that the approach to market segmentation put forward is reasonable. We have assumed that the voltages quoted in the table refer to the customer connection voltage rather than the voltage of the connection to the DNO network.

We also include our own definitions in our confidential Appendix B3 which shows how Central Networks segments the market in practice.

3.4.2 Feasibility of competition

Table 2 of Appendix 7 in the Policy Paper appears to be reasonable for the timescales covered by DPCR5.

3.4.3 Level for regulated margins

We believe that allowing margins on connections activity will be a positive step in encouraging competition. It is difficult to determine whether the benefit to the customer of greater competition will outweigh the short term increase in costs due to including the margin. However we believe that customers accept that commercial companies need to earn fair margins and that competition offers customers wider choice while exerting downward pressure on prices. We suggest that a reasonable return is allowed on a net margin basis.

Ofgem's policy paper suggests that margins should only be allowed on the contestable elements of the charges. This may present some practical challenges as whilst estimates may be prepared to indicate the split between contestable and non-contestable elements, it does not follow that this split is reflected in the systems to process actual costs. This is the case for Central Networks where the split is reflected in the modular costing system but not in the cost reporting and therefore system and process changes would be required. For section 16 connections, the complexity of

splitting the work into contestable and non-contestable elements and allowing a margin on the contestable element only seems unnecessarily complex. At Central Networks the same team will complete both the contestable and non-contestable element with equal quality and efficiency so to subdivide the work according to what could have happened in terms of competition seems to impose disproportionate cost on the DNO while providing relatively little benefit for the customer.

3.4.4 Competition Tests

We believe DNOs should behave in a way which facilitates competition. However there are other factors beyond a DNO's influence which affect whether other companies compete for new connections work in a geographic area. These factors include the costs of New Roads and Street Works Act (NRWSA) / Section 50 Town and Country Planning Act, and the potential margin available which in turn will affect the commercial attractiveness for potential competitors. Therefore we agree that market share on its own is not a sufficient indicator of whether the conditions for a competitive market are met, and in terms of determining whether to allow margins then more emphasis has to be placed on the DNO's behaviour in facilitating a competitive market than the actual outcomes. Similarly, it would not be in the customer's interest to create a perverse incentive whereby DNOs are incentivised to reduce their market share to ensure their ability to charge a margin, therefore market share should be used with care within the process to determine whether markets are competitive.

In determining whether the segments of the electricity connections market are competitive, comparisons with the gas connections market may be misleading. For sound technical reasons the process is simpler for gas connections with less need to liaise with the Gas Distribution Networks (GDNs), allowing independent connections providers greater flexibility and control for scheduling and carrying out work. Thus greater apparent competition in the gas connections market partly reflects a difference in the attractiveness and practicality of the activity and therefore a lower level of competition in electricity connections is not necessarily a failure of electricity DNOs to facilitate a competitive market.

The tests should be evaluated per DNO for each relevant market segment, rather than the entire connections market. For example, the tests should be applied to a segment such as LV medium enterprise and commercial (5 premises and above / greater than 70KVA per connection) to determine if unregulated margins are appropriate for that market segment, rather than applying tests at the whole LV market level or for connections as a whole.

We provide more detail on the proposed indicators to be used to determine whether each segment of the market is competitive in our Appendix B4.

3.4.5 Timescales

We believe the three year timescale is a reasonable time to operate with regulated margins for competitive connections and that competition can be displayed in this timescale. This timescale also allows sufficient time to agree the market segmentation definitions within the industry and determine and trial the set of market tests for each market segment.

3.4.6 Customer Service where competition is unlikely i.e. small scale domestic connections

The customers for these connections will want work to be carried out to reasonable and defined timescales, and at a price which reflects an efficient operation.

In terms of efficiency, we believe that the customers who are unlikely to benefit from direct competition still benefit from competition in other segments indirectly. Competitive and non competitive market connections will be served by the same people, using the same practices and methods, and benefit equally from improved efficiency that is stimulated by the competitive segments. Therefore we believe that any changes to the framework should ensure reasonable timescales to mirror the standards already set.

Our response to the various options for such customers unlikely to see competition is given below.

Table 2 – Options to Improve Customer Service Where Competition is Unlikely

Extending regulation to all connections	This is our preferred option as this appears to address the issues of most importance to customers i.e. the timescales of work. The additional cost incurred handling the data to ensure compliance will be absorbed by the operational overhead.
Price regulated segments	We agree that standard pricing across all DNOs would not be feasible. Standard charging may be feasible but would require cases where this applied to be very tightly defined, so that there would be little variation between the costs of the jobs covered by the standard charging mechanism. If there is little variation between the likely costs of the job this would produce a fairer system and is less likely to result in a customer being charged significantly more under a standard mechanism than a bespoke cost estimate. Another reason why standard charging would require very tightly defined scenarios is to prevent "cherry picking" by competitive companies that do not have universal service obligations, which would also lead to higher costs for customers as a whole. Therefore standard charging may only be applicable for single urban domestic connections. Price capping does not seem to be an appropriate solution due to the difficulty of determining the appropriate impact of geographical cost variations. Fairness to customers would be ensured by DNOs charging on a cost reflective basis. This is echoed in Section 19 of the Act which allows recovery of our reasonable expenditure for the provision of a connection. If we are not recovering our reasonable expenditure, then the costs above the cap would need to be smeared across the rest of the customers which would not appear to be a fairer solution.
Price accuracy	The price accuracy scheme appears to simply ensure that the DNO's own approved methodology for charging is being followed. This

scheme	could be workable if safeguards were in place to prevent opportunistic appeals. However this would not address the issue of timescales for quotations and delivery. It is likely that, if customers were unhappy about the way in which their connections were costed, this would be reflected and resolved by the normal mechanism for customer complaints.
Cost efficiency incentive	The level of uncertainty of predicted workload, actual work volumes, work phasing, real price effects and differences in efficiency is currently too high to devise a workable cost efficiency incentive for the start of DPCR5. It is likely that these connections will be undertaken efficiently if the other connections activities undertaken by the DNO are also efficient.

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?

We believe that some changes are required to the way in which the IIS incentive operates.

- The target setting methodology for CMLs should use a 66th percentile position in favour of an upper quartile position to avoid cherry picking effects.
- Guaranteed Standards (GS) exposure for large scale one-off events should be capped at a similar level to exceptional event exposure to recognise that mitigation measures are unlikely to be cost effective.
- Moving from fixed bandwidth and variable incentive rate to a fixed incentive rate of £8.50 per customer and variable bandwidth would allow DNOs to fund improvement work on a more equal basis.
- Extending the IIS scheme duration would allow for longer term thinking and would extend the number of viable projects.
- We agree with the proposed revised auditing regime.

However, some elements of the current incentive should remain unchanged.

- The treatment and definition of exceptional events should continue as it is, to ensure consistency of IIS data and clarity of information for to customers about whether an event is exceptional.
- One-off events should continue to be excluded regardless of cause, given the higher risks associated with an increased work programme and the disproportionate cost of risk mitigation measures.
- Planned interruptions should continue to have their own performance allowance rather than be replaced with a financial allowance associated with the work programme.
- Overall exposure to the network performance element to remain at 3% of revenue, but there could be scope to alter the split to 1%CI and 2%CML to overcome the concerns of CI contributing disproportionately to CML.

- The penalties and rewards should continue to be symmetrical as the DNOs face more downside risk, particularly where targets are tightened.
- Whilst DNOs should improve their communications with business customers, they should remain with the same weighting within the IIS scheme.
- CIs and CMLs originating on the EHV and 132kV systems should continue to have the same weighting as other CIs and CMLs.
- We do not believe there are redundant Guaranteed Standards which should be removed.

The reasoning that underlies our position on these issues and more detailed comment on the full proposals can be found in Appendix B5.

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?

As an ideal, DNOs would like access to any information that enabled them to improve their service to customers. Information is not an end in itself, rather it is the use to which the information is put which will determine its value. Another test that we should apply is whether alternative solutions provide the same benefits, but at lower cost, to ensure value for money. Thus the question we should be asking is not simply could we make use of this information to provide a benefit, but is this the best way to provide that benefit. In practice, whether DNOs should have this long term objective of having real-time precise customer energisation information depends on whether the benefits of having this information outweigh the costs of providing and managing this information.

In addition to this theoretical analysis of the value of information, we also need to consider the practical issues and costs of obtaining information from smart meters, particularly when roll out structures, communication methodology and meter functionality are yet to be finalised.

The benefits from smart metering generally relate to:

- accurate billing;
- lowering consumption by increasing customers' awareness of their consumption;n
- specialised tariffs to support load management; and
- integrating household renewables.

It can therefore be expected that many of the benefits from smart metering will relate to activities carried out by retail and generating companies.

These issues seen from a DNO perspective are outlined in more detail in Appendix B6. However, in summary it appears that benefits in terms of real-time outage notification are limited as much of the information that smart metering could provide will duplicate the information provided by DNOs' own remote indicating devices on the network, which are expected to increase in number in the coming years. Issues concerning cross-referencing data from smart meters and control systems would limit the practicality of using this information in real time, especially given that customers are likely to want to

communicate with their DNOs to obtain further information. Smart metering information may not alter the initial location or the type of person despatched to an outage.

The costs of providing the potential benefits are largely unknown with a high degree of uncertainty as to whether functionality could be supported. There are also questions as to whether satisfactory commercial arrangements could be agreed that ensure DNOs can be reliably provided with data at the lowest possible cost.

There may, however, be a role for using data collected from smart meters which does not rely on real time data transfer. This could help improve the accuracy of reporting short interruptions and improve the validation of failure of the multiple interruptions standard. The data could potentially be used to validate engineering models for losses which would not rely on having total national coverage in place.

The area where we believe smart metering will provide most benefit is to enable smart grids and localised load management or optimisation of losses. This kind of project would operate in a known defined zone and therefore would not require the national roll out to be completed before they could operate. It is also likely that a full understanding of the implementation and running costs could be evaluated and considered as part of the project authorisation. For the zone in question the costs of providing smart metering and ongoing communications could be balanced against the alternative costs of network investment such that customers would see the benefits of providing this information to the DNO, simplifying the commercial arrangements around access and provision of this data.

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

We support the approach of using dedicated allowances to fund approved schemes to improve the service to worst served customers.

3.7.1 Definition of worst served customers

The suggested definition of worst served customer is those customers that have experienced more than 15 unplanned HV interruptions (not including short interruptions) over three years.

It may also be prudent to add in a further qualification to ensure that spurious periods of bad performance do not distort the definition. For example if a circuit experiences 11 faults in year one, two faults in year two and a further two faults in year three, the circuit will qualify as being worst served but the problem may already have been addressed.

Thus, either the definition should be three consecutive years of five or more HV faults, or 15 faults over three years but with no single year having fewer than N faults. N could be reasonably set at either three or four and would apply across the industry after investigations by the DNOs have determined which value they feel helps to better identify worst served customers.

We think it is not sensible to include pre-arranged interruptions in the definition as often planned work is required to solve the problems of worst served customers and

could be interpreted as increasing them.

We believe that this definition will be the most practical to use to identify worst served customers, both in terms of identifying customers likely to benefit from directed improvement schemes and also for improving communication with worst served customers.

3.7.2 Allocation of allowances

We welcome the proposed allowance for improvements specifically for worst served customers, but feel that the value should be increased. It is generally accepted that customers broadly consider reliable service to be more important than visual amenity, so the allowances should be in excess of those provided for undergrounding in AONBs.

When considering how the proposed allowance should be allocated to DNOs, we suggest that it is more logical to split the allowance by the number of worst served customers, i.e. option 3 for table 14 in the appendix. If the schemes result in similar overall average cost per benefiting customer then splitting the allowance equally between DNOs would result in overly generous allocations to DNOs with few customers likely to benefit from such schemes while limiting resources to DNOs where more schemes would benefit more customers. Given that the worst served customer schemes will be subject to approval and will have to meet criteria in terms of minimum improvement levels, allocating allowances on this basis does not give those DNOs with larger allowances any unfair advantage.

3.7.3 Average Cost per Benefiting Customer

Given that the cost per benefiting customer found from examining actual DNO proposals was in the region of £2000, we suggest that it would be unrealistic to set this limit any lower than £1000 per benefiting customer.

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

We have addressed these questions in our answers given above.

Chapter 4

Networks

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

The behaviours identified in paragraph 4.7 of the policy paper are broadly right and are aligned with the priorities of our business.

Our Priority	Behaviours from Paragraph 4.7
Safety	
Zero injury, great health and minimal environmental impact	• Ensure the safety of employees and the public
Network performance	
A reliable network with minimum impact on customers when faults occur	• The network should be managed at an efficient cost for an appropriate level of risk and other outputs
Customer service	
To put our customers first in all that we do	• Implicit in other desired behaviours and referenced elsewhere (e.g. paragraph 3.11 of the policy paper)
Cost	
To be recognised internally and externally as a responsible and efficient operator	• Reassess the cost base regularly to improve efficiency
A sustainable network business	
A sustainable workforce model, efficient and engaged with the changing energy landscape To invest in our network for a secure and sustainable future To make it easy for our customers to deliver low carbon energy schemes	• Invest in a sustainable workforce • Investment should be at a sustainable level • Decisions should be made on the basis of whole-life costs including the impact on the environment • Support innovation and development • The level of expenditure should take account of the long-term requirements of customers • Facilitate the development of competition in supply and generation and development of DG

The last two items on Ofgem's list seem less like general behaviours and more like specific obligations. On the first, as the level of complexity and uncertainty in electricity distribution increases, reporting requirements are becoming more onerous. We take our obligations extremely seriously and have robust reporting processes in place. However, we encourage Ofgem to ensure that the level of detail requested of companies is proportionate to the benefits to customers.

On the final bullet (joined up business and regulatory planning), this is exactly how we are managing the DPCR5 submission – our business planning team co-ordinates both our internal plan as agreed with our parent and our DPCR5 FBPQ submissions. Whilst the timescales may differ, the plans are therefore aligned.

In general the regulatory framework is able to incentivise these behaviours, but with some changes needed to support development of sustainable businesses and facilitation of distributed energy schemes. These issues are covered in more detail in Chapter 2.

The behaviours listed by Ofgem reinforce the shift of electricity network regulation from a cost-cutting framework where efficiencies have historically been relatively straightforward to secure, to a much more complex environment. Regulation now has to provide incentives for efficient investment, long term asset stewardship and facilitation of government energy policy. Sustained efficiency improvement above and beyond the rest of the economy is no longer plausible.

A "sustainable business" consciously balances longer term efficiency with short term cost. For example, we are building an alliance structure with our external service providers (ESPs) that will require a degree of certainty in the work programme in order to ensure efficient delivery. Whilst we will manage this risk, it is an example of how innovation and risk are linked – a recurring theme that needs to be factored into DPCR5.

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

At DPCR4, Ofgem recognised that increasing investment was required to maintain the network. Specifically, the DPCR4 settlement provided allowances on the basis of the minimum expenditure necessary to run an efficient business whilst maintaining existing performance standards. DPCR4 provided an incentive for efficient forecasting and delivery of asset management in the form of the IQI incentive, about which we make the following observations:

- it was designed to incentivise companies to plan robustly, rewarding outcomes which are closely aligned with Ofgem's view of network needs
- it shares risk and benefit between companies and customers, and customers will benefit almost twice as much as companies from any efficiencies.

Our capex allowances awarded at DPCR4 were extremely close to our forecasts (99% and 98% of forecast for Central Networks West and East respectively), and differed from PB Power's estimates by less than 10%, demonstrating consensus about network investment needs and supporting the robustness of our initial forecasts. Our responsibility as an asset manager was (and still is) to react to change in a measured way against the DPCR4 framework and deliver the outcomes specified in the price control.

During the DPCR4 period, we have seen risks change in a way that could not have been envisaged when the original forecasts were made. The DPCR4 agreement was a package. In some areas we have gained, but in other areas (e.g. growth) we have lost out. Some of the biggest drivers of our RORE outperformance were due to risks that we agreed to bear on behalf of customers (tax, interest). It is perfectly possible that things could have turned out differently and companies would have achieved a lower return. In the case of investment, prices for labour, equipment and materials have risen beyond initial expectations.

Outturn performance is currently predicted to be within only a few percent of the DPCR4 plan. We have been able to absorb the impact of rising prices by choosing to reinvest savings from the merger that created our business to. We believe this reflects prudent management and the rational response of a business to an incentive framework.

We believe we have therefore delivered against the contract and will continue to do so, even going beyond it in some areas. Total fault numbers for our networks have remained stable across the period, and the number of customer minutes lost per fault has improved. We have invested in innovation and development – we were the first company to build a Registered Power Zone, for example. We have invested heavily in recruitment and training of a workforce to deliver the DPCR4 package, but also to prepare for the increasing level of investment required by our network, developing a delivery partnership model to improve efficiency and take us into the next price control period. We have controlled our operating costs, but the industry as a whole is overspending opex calling into question the appropriateness of the upper quartile opex allowance and productivity expectations set at DPCR4. Our customer service has been recognised as leading by Ofgem's discretionary award panel. Our prices to domestic customers are amongst the lowest in the country.

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

The vast majority of volume risk is outside the control of the DNO. Ofgem have suggested that companies are able to influence connections volumes, particularly through uses of system charges. We agree that in theory at least, a limited amount of influence is possible. However, our influence is limited by the following factors which will need to be borne in mind when assessing how effective companies have been in finding alternatives to traditional investment (paragraph 4.47) :

- DNOs do have some ability to defer investment by taking on additional risk and/or by implementing alternative measures, although control is limited. For the majority of distributed generation projects, we agree with Ofgem's comment in appendix 14, paragraph 1.23, that there seems to be "no evidence at present that GDUoS charging impacts the feasibility of renewable schemes." In other words, our ability to influence the location of generation schemes is constrained by the more material drivers that developers face (mainly planning, environmental and resource constraints). Our stakeholder engagement supports this view.
- Where distributed generation or demand side management measures can be employed, their effect may sometimes only be temporary (especially for early projects), although there is clearly a short term benefit to customers.

- The period of deferral before an alternative solution can be commissioned, and probability of success, together with the level of network risk will also affect a DNOs decision whether or not to reinforce.
- As we set out in Chapter 2, further development of the regulatory framework is needed to better support development of innovation engagement capability and provide the level of commercial certainty needed to accept increased risk. These elements are required to enable companies to create opportunities proactively and then respond to them.

We therefore support the use of capex driver schemes, subject to identification of appropriate drivers and baselines and interactions. The aim of such a mechanism should be to manage volume uncertainty currently managed with the growth term in the price control. To avoid duplication and overlapping mechanisms we would then expect upstream and general reinforcement to be removed completely from the IQI assessment. This is reasonable and does not jeopardise customers' interests since Ofgem will set an allowance for the revenue drivers and the scope of the IQI incentive mechanism and business plans (i.e. a central case) need to be aligned. Other alternatives are possible (e.g. a separate IQI assessment for load related expenditure or ex-post recalculation of the IQI incentive rate based on an adjusted allowance) but these would add complexity and reduce transparency to stakeholders.

We support the use of triggers for high materiality projects. We suggest that this could include uncertainty relating to major diversion projects arising from wayleave terminations. We have included a nominal allowance for these costs in our business plan based on experience in DPCR4. If these costs are not allowed ex-ante, then some form of logging up would be required, since these projects may generate capex requirements of £8-10m or more per project, are unpredictable and largely outside DNO control, as we only carry out such projects if they are a least cost solution to a termination request.

The level of expenditure required to facilitate DG is also uncertain. We anticipate that, provided the strength of the DG incentive is sufficient, project-specific reinforcement costs arising from new connections should mostly be covered via the DG incentive and the modified IQI mechanism. Our remaining concern is a scenario where there is a high take up of DG, electric vehicles (EV) or electrically driven heat pumps, driven by a focussed change in policy to meet 2020 goals. Although the likelihood of significant impact much before 2013 is unlikely, the resulting change in delivery requirements (e.g. a change in primary or secondary reinforcement programmes), together with constrained resource would mean that the efficient and complete delivery of our remaining outputs would be brought into question. Probably the best way to handle this would be to ensure that outputs are kept constantly under review as part of the RRP process, together with an agreed procedure for modification should material new information come to light. Alternatively a reopener opportunity could be provided towards the end of the period. This could be based on:

- DG, EV or heat pump installation volume density exceeding a threshold (which may be different for different voltage levels and circuit type or location), and/or
- evidence that the DNO is unable to deliver agreed outputs due to an accelerated change in demand for particular types of activity.

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

We believe that DNOs are in a better position to manage price uncertainty than volume uncertainty. Our own assessment has shown that there are likely to be significant practical difficulties to overcome in setting trigger and index levels, particularly as price sensitivity is dependent on work mix (para. 4.52). Hence, we would suggest that price risk could be best covered by a modified IQI uncertainty mechanism. This would balance increased risks against reduced exposure for customers and companies alike, and provide a degree of price certainty, which suppliers for example have expressed a preference for.

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

We support Ofgem's desire to equalise opex and capex incentives to give companies greater flexibility in employing "non-network" alternatives, or simply making the asset management trade-off between capital spend and maintenance or repair work.

Flexibility is also important for delivery, where we will be implementing an innovative alliance delivery structure. In order for this to work best for customers it is important that artificial and unnecessary distortions arising from cost allocation are removed. It therefore makes sense to look at aligning opex and capex incentive rates by including both opex and capex under a modified IQI mechanism.

The fixed additions to RAV concept has some appealing aspects, although it will only really work with equal opex and capex incentive rates. Any disparity in rates could still potentially provide incentives to over or under capitalise since outturn work is highly unlikely to be exactly equal to plan, even if total amount spent is close to expectations.

Our preferred approach is to capitalise costs based as closely as possible on their nature, using statutory accounting drivers or relevant proxies wherever possible. A fixed RAV approach is essentially a weighted average of this process, but keeping at least some basic categories separate helps transparency and better reflects the nature of work. This would not have to be complicated – four overall categories could be sufficient:

Group	Potential Activities
Group 1	
Direct capex & opex	Load related capex
	Non load related capex
	Faults
	I&M
	Tree cutting
	Non-op capex
Group 2	
Engineering indirects	Project management
	Network design & engineering
	Engineering management and clerical support
	Vehicles & transport

	Stores
	System mapping
Group 3	
Network indirects	Network policy
	Call centre
	Control centre
Group 4	
Business indirects	IT&T
	Property
	H&S and ops training
	HR & non-op training
	Finance & regulation
	CEO etc.

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

We have already submitted our views to Ofgem on this subject in the form of a paper by CEPA. CEPA's view is that it is possible to make the adjusted regime broadly and effectively incentive compatible.

Our mechanism is attractive because:

- it avoids unnecessary complication from many triggers and drivers and a need for Ofgem to "micromanage" expenditure – incentives for efficient choices still rest with the company;
- it provides incentives for efficient ex-ante forecasting and ex-post delivery;
- given increased uncertainty in DPCR5, it provides protection for companies and customers. For specific high impact risks, triggers can still be used (e.g. for a reopener or revenue adjustment) and a cap would be placed on incentive rates.

We disagree with the suggestion that incentive rates should be higher in the "central" zone as this makes an implicit assumption that all the risks in this area are controllable. Rather, because costs are so uncertain, the likelihood of company or Ofgem forecasts being accurate is, we believe, lower than in previous reviews. Consequently, a graded incentive is required to deal with this uncertainty, providing incentives for companies to innovate to create genuine reductions, whilst providing disincentives for inefficient overspend.

Clearly, there needs to be consistency between the scope of companies' forecasts and the assessment carried out by Ofgem to arrive at the IQI menu (e.g. inclusion or exclusion of flooding or high-impact-low-probability events, exclusion of load related volatility manged via appropriate drivers, etc.) Similarly, we note that some of Ofgem's proposals (e.g. using smart meters to improve real time fault information) would increase opex costs significantly. Given the uncertainty surrounding these costs we do not believe it is prudent at this stage to include anything other than very high level early preparatory costs in our plan submission. If opex is included in the IQI mechanism

(and we believe it is appropriate to include at least direct opex) then the IQI scheme must take account of any agreements made later on in the price control discussions.

The aim of managing uncertainty in DPCR5 should be to maintain companies' and customers' risk exposure aligned with an appropriate cost of capital. Where companies are exposed to additional risks not captured by an appropriate IQI mechanism[1], triggers or drivers, these risks should be reflected in an increased cost of capital. For clarity, our initial view on the key uncertainty mechanisms is illustrated below:

Table: Potential Uncertainty Management Mechanisms for DPCR5

Uncertainty	Mechanism
Cost of capital	A symmetrical trigger mechanism or reopener (see Chapter 5).
Pensions	Use of interim valuation (see Chapter 5).
Tax	Reopener with materiality threshold (see Chapter 5).
General and specific reinforcement costs	General reinforcement revenue driver - based on expected demand profile at highly loaded substations. Specific reinforcement driver – hybrid of connection numbers and load. Existing DG incentive retaining current strength (we believe initial costs have been cheaper due to cherry-picking effect).
Risk of accelerated growth of low carbon technologies	A reopener or output review (for demand and generation).
Price effects	Allowance and modified IQI.
Non-load replacement costs	Modified IQI and output review for material new information (i.e. a materiality threshold – for rising mains / laterals or a type fault for example).
Innovation risks	Engagement allowance, opex-capex equalisation, innovation incentive recognising increasing underlying risk (Chapter 2).
Diversion costs arising from wayleave terminations	Agreed notional allowance or logging up.
Transmission exit charges	Continue current pass through arrangement.
Smart metering costs	Allowance / modified IQI with a reopener if the scope of required work is insufficiently clear before the final DPCR5 proposals.

[1] We note for example that the IQI mechanism is a risk *sharing* mechanism – it does not cover all risk exposure – additionally other incentives will also affect risk.

Traffic Management Act	An allowance / modified IQI approach is possible if there is sufficient clarity on likely costs by the final proposals. However, as this is highly unlikely we suggest a reopener provision should be retained.
BT 21st Century	Allowance / modified IQI, opex-capex equalisation, logging up beyond a materiality threshold.
Other change in legislation (e.g. congestion charge)	Modified IQI or logging up (materiality threshold as per BT 21st century).
Other risks (e.g. climate driven increases in I&M or tree cutting costs, increases in training costs beyond an agreed allowance etc)	Modified IQI.
Remaining risks created by incentives (including IQI), regulatory uncertainty and general underlying business risk.	Cost of capital.

We believe the above proposals will provide the right balance in managing uncertainty between companies and customers, who also value simplicity and predictability.

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

We should like to make it very clear that we support the principle of outputs, and understand that as investment rises it is reasonable for the level of scrutiny applied to delivery to increase. Defining output measures is an important step in this process.

Our business plan proposes a sound and comprehensive set of output measures. They have been developed and proposed in a spirit of openness and we want to work proactively with Ofgem to develop the outputs framework. We agree that where outputs are not offered then it is reasonable for Ofgem to apply additional scrutiny, and/or weaker IQI incentives.

Whilst we are supportive of proposing such outputs and believe they represent robust investment drivers, we are conscious of the developing understanding around such measures and the data that supports them. A completely inflexible output regime would potentially inefficiently constrain DNOs and disproportionately increasing delivery risk., potentially driving companies to suggest less demanding outputs to manage that risk.

We therefore believe it essential to agree to maintain a measured and productive dialogue. This could be easily incorporated into the annual RRP submission and review visit process, to ensure that companies and Ofgem review progress, providing DNOs with an opportunity to propose any alteration to their overall DPCR5 output measures. Such amendments could result from new network information or external factors not know at the start of DPCR5.

This kind of approach recognises that any business may need to change its plans in reaction to events and is not without regulatory precedent. As well as providing a

financeability reopener, ORR, for instance, provided a 'material change in circumstances' re-opener in its recent CP4 determination[2].

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

The tasks for undertaking successful cost assessment for DPCR5 are:

- Ensuring data is as free from distortion as possible by careful choice of costs to be included and cost normalisation adjustments.
- Using the correct drivers to represent the factors influencing costs.
- Using a range of methods to get a rounded view of efficiency.
- Combining these different views of efficiency transparently and repeatably to set allowances.

The approach outlined in Appendix 8 of the policy document acknowledges these issues and contains a number of sensible suggestions. However, the detail of how the cost assessment will be carried out is not yet specified so it is not possible to comment on every aspect of at this stage. Where we do have more detailed analysis or proposals we have included this in Appendix C. We broadly agree with the approach set out in Table 1 of Appendix 8, and have commented on each item in turn in Appendix C1. We would like clarification as to whether the training costs referred to in Table 1 relates only to apprentice training costs as the bottom up cost analysis suggests that the majority of training costs will be included in the traditional regression analysis.

Our key points on benchmarking are summarised below. The remainder of our answer deals with the treatment of specific costs.

4.8.1 Summary of Key Points on Cost Benchmarking

Three versions of the top down benchmark should be used	• A 'DPCR4 style' Opex plus faults costs vs. network scale • A single year total costs vs. a combined metric representing capex workload and network scale (see detail below this table). This will help overcome opex capex boundary issues. • A total cost measure using long term average non load capex and current opex and indirects to normalise for long term opex capex tradeoffs and volatility.
Regional adjustment only valid for London	A positive adjustment should only be applied to London and South East. The scope of this adjustment should be limited to the activities or parts of activities which must be carried out in that

[2] See "Procedural approach to conducting an interim review in CP4" on ORR's website: http://www.rail-reg.gov.uk/upload/pdf/pr08-ir_proc.pdf. This document also sets out the rights and responsibilities of ORR and Network rail.

and the South East	location. We have included further analysis and a counter proposal to support this argument in Appendix C3, and further comment below this table.
The analysis can be simplified by excluding atypical and including related party margins	Whilst carrying out two or three versions of the analysis for pensions will establish sensitivities, variations for related party margins are not needed. The same is true for atypicals which should be excluded (subject to successful analysis and reclassification of EDF atypicals by Ofgem).
We support the use of international data to gain a wider view of UK DNO efficiencies	We have taken part in international benchmarking studies carried out by Cap Gemini initiated by the French regulator, and are familiar with the issues that can occur when comparing these data sets. The results show UK DNOs (including Central Networks) to be the most efficient amongst the sample set. More recently we have undertaken international benchmarking of DNOs within E.ON. Both of these studies have highlighted some important issues affecting cost comparability which will need to be taken into account. We would be pleased to share this understanding with Ofgem and have provided more detail in Appendix C2.
Related party margins should remain within benchmarked costs	If margins are inefficient, this should be reflected in the overall cost assessment. The scale of variation in of related party margins between DNOs is such that excluding these costs is more likely to introduce distortion than including them. We do not believe that it is necessary to have two versions of the analysis with and without related party margins.
With opinions divided among the DNOs it is sensible to examine each of the three options that Ofgem proposes	We agree that while no ideal normalisation has been determined, the errors associated with normalisation if pensions costs are to be excluded in the benchmarking by adjusting contractors costs, are significantly less than the errors associated with trying to normalise the pensions costs that have been included for pre-payments, actuarial assumptions, review timings etc. Similar issues will arise in determining the normalised rate to be used for each DNO. It is not clear how these results will then be used to choose either the "best" method to use, or how these different results would be combined within an allowance setting methodology
By their very nature, unusual events are not representative of normal costs. Atypical events should therefore be excluded from benchmarking.	The majority of atypical costs relate to fault costs during exceptional events, around which there are robust criteria to ensure consistency. Given that Ofgem intends to review and adjust costs where DNOs appear to have interpreted the definition of atypical costs incorrectly, there would appear to be little justification for including these within the benchmarked costs. We agree however that there is a need to determine the likely cost of exceptional events in DPCR5 and that these atypical costs may be useful in that process if the definition of an exceptional event is to remain the same. As exceptional events are unlikely to average out over three or four years then it may be useful to consider

	longer term data.
Adopt a "depreciation" smoothing for non-op capex	We agree that Non op capex expenditure should be redistributed to the activities to which that expenditure relates. Given the difficulty in averaging expenditure, we believe that non operational depreciation will be more representative of annual spend and enables comparability between DNOs with different policies to lease/buy.
We support the use of a number of different methodologies, but the final approach needs to be replicable by companies.	This was an important principle established at DPCR4, which has helped stakeholders to understand Ofgem's proposals and DNOs to manage their businesses. Although we would anticipate some simplification as sensitivities are explored, and the statistical relevance of different models established, we would expect the final approach to combine results from a number of different approaches. Some degree of complexity is necessary and acceptable, but the final method should also be replicable and transparent.

4.8.2 Labour & Contractors Regional Adjustment

We welcome Ofgem's proposal to limit regional cost adjustments to activities which are location specific. We believe that DNOs that operate in London and the South East should be able to identify the proportion of their reported FTEs for these activities that operate within different distance bands from the centre of London and that an appropriate London weighting can be applied to represent the impact on salaries for those staff whose activities must be carried out in that region. We do not believe that there is sufficient variation in pay structures outside of Greater London to warrant a regional cost adjustment, either for DNO staff or contractors costs and this is substantiated by comparison of DNO costs given in Appendix C3, which is confidential due to the inclusion of salary data. Appendix C3 also contains a different proposal for assessing regional salary weightings.

Furthermore this data suggests that the difference between industries is likely to exceed the differences between DNOs which would suggest that an approach that compares labour costs from a wider variety of industries is more likely to introduce error than correct for it. For this reason we do not support the use of comparative regional salaries that have been derived from a mixture of industries within a region. Whilst specific problems have been identified with ONS data for the Aberdeen area, they are indicative of the kind of issue that affects the ONS data in general. Whilst the impact of offshore oil and gas workers shows a distortion which is detectable, there are likely to be other distortions from other industries which also influence the results, but are less obvious. Removing specific data won't therefore correct for this issue.

Further analysis of the opportunity for error associated with such an approach is given in Appendix C3.

4.8.3 In-Outsourcing & Capex workload

We agree that the cost assessment process needs to account for the differences in indirect costs that result from different levels of outsourcing. We also believe that the impact of different levels of insourcing is similar to the impact of different levels of

workload and that it may be possible to create a combined adjustment to normalise a top down benchmark for opex costs for both effects concurrently.

Simplistically we could consider the indirect costs that are most closely related to workload (rather than network scale or being constant per DNO group) to be related to four factors

- The volume of opex work carried out by DNO s own staff
- The volume of opex work carried out by contractors
- The volume of capex work carried out by DNOs own staff
- The volume of capex work carried out by contractors.

Analysing the relationship between these costs and the workload related indirect costs suggests that as expected work carried out by DNOs themselves has more of an influence on the indirect costs and that of the direct opex categories, I&M workload has more influence than faults or tree cutting. Comparing results for different years suggests that the composite driver for workload related indirects should be calculated as:

$$Composite\ Workload\ Driver = 0.6 \times C + 0.97 \times (I + F)$$

where

$C =$ direct insourced labour costs for capex (£m),

$I =$ direct insourced labour costs for inspections and maintenance (I&M) (£m),

$F =$ direct insourced labour costs for faults (£m).

While a solution would be preferred which did not use spend as an indicator for workload, no suitable alternative metric has been developed for representing the inspection and maintenance activity, nor can the additions and removals from the network specified in table 5.3 of the RRP be split between contractors and DNOs own staff.

When only opex costs are considered, the effects of scale on costs tend to be greater than the effects of different levels of workload or insourcing and therefore it is difficult to create a composite driver to account for both effects. Therefore we suggest that the workload driver is used to determine a correction.

$$Insourcing\ and\ workload\ correction = Regression\ costs\ when\ benchmarking\ workloadrelated\ indirect\ costs\ against\ workload\ driver - Regression\ costs\ when\ benchmarking\ workload\ related\ indirect\ costs\ against\ network\ scale$$

Another way of normalising for these differences is to benchmark the total distribution costs against a metric which represents both network scale and the degree of capital work undertaken. As both opex and capex costs are considered, there would be no requirement to calculate the proportion of contractors' costs that relate to indirect costs. This also has the added benefit of normalising for potential differences in capitalisation of fault costs.

In this case, it is appropriate to create a metric for capital workload which represents the theoretical cost of all the additions and removals from the asset base that are reported in the regulatory reporting pack. Ideally refurbishment work would also be included if this has not been reported within the inspection and maintenance category.

This workload metric would be suitable for combination with an indicator of network scale.

4.8.4 Complexity & Replicability

At present there are several issues for which the best path to take is not clear and this is reflected in the policy paper suggesting that various options are explored. We believe that while it is appropriate to use several variants of cost exclusions and adjustments to determine their impact we will need to decide how those results will then be used.

Given the number of issues where different options are possible the total number of possible variants can become unmanageably high. This is especially true if the number of variants is then multiplied by the different possibilities in terms of method (OLS single year data, OLS average data, Panel data, DEA) and cost function (linear, log for one axis, log for both axes.)

However the breadth of the range of results at each stage could prove valuable in indicating the potential error within the cost assessment which will need to be taken into account by the allowance setting method. We therefore anticipate some slimming of the process to a number of key methods. These could be combined, for example through an averaging process, to create a transparent and replicable mechanism.

Whatever is decided, the main point is that DNOs will need to be able to replicate the results of the cost assessment methodology, firstly to satisfy themselves that the agreed method has been applied correctly and secondly so that they can continue to use the method during the price control to assess their ongoing efficiency.

Further detail on this section in can be found in Appendix C:

Appendix C1	Cost groupings and cost drivers
Appendix C2	Benchmarking techniques
Appendix C3 (Confidential)	Regional Cost Adjustment
Appendix C4	Costs to exclude from regression

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

4.9.1 Load-Related Expenditure.

We are extremely supportive of Ofgem's principles and note the similarity to some of our own cost assessment techniques.

4.9.2 Non-Load-Related Expenditure.

We would caution against placing excessive emphasis on the use of reported RRP asset data over a short period to draw any conclusions regarding asset replacement lives. This is because:

- Internal asset register and project management systems may not be linked, requiring simplifying assumptions about replacement drivers to be made when compiling the RRP asset data. These assumptions may differ between DNOs.
- Three years' worth of data is unlikely statistically to provide sufficient confidence to draw any conclusions about the validity or otherwise of our modelled asset lives
- Any misalignment between actual and target asset lives in itself is not evidence of poor asset management – companies may have to change their priorities to meet wider objectives.

Also, we note that our implied asset lives are already relatively long and therefore we believe that the forecast volumes are a good balance between asset stewardship and risk management. Finally, as part of deferment of load related investment we accept in some cases it is reasonable to allow for a controlled additional amount of loading at highly loaded substations. However, this additional loading will have a consequential impact on system risk and reduced asset lives.

4.9.3 Other Expenditure.

This should be assessed on a case by case basis informed by input from stakeholder engagement as the drivers for investment are different. Applying a blanket assumption about asset management capability fails to recognise the potential criticality of security or flooding resilience projects and specific input from stakeholders, or the different nature of risks the programmes are designed to mitigate.

4.9.4 Unit Costs

We support the principles behind the additional information requests Ofgem has issued to improve unit cost estimation. However, it is extremely important that companies working with Ofgem are able to get this right, in order to avoid distortions. As was found to be the case in DPCR4, the potential for variations in comparability is large, arising, for example, from different sites, technical specifications or scope of work. Therefore, a degree of pragmatism will be required and the assessment of unit costs should not be approached too simplistically, quickly or rigidly.

HILP (1.111): We would welcome views on how the costs relating to HILP event mitigation should be funded.

The costs relating to HILP event mitigation should be funded through DUoS charging of the entire customer base, in continuation of the current policy. There have been proposals that these costs be funded through a separate DUOS charge to business customers in the areas affected by this work. This would be an unprecedented move, and would be inconsistent with the cross-subsidy which already exists, for example in the service provided to rural customers, and indeed which is being proposed by Ofgem for the costs related to the mitigation of flooding in low-lying areas. It is also based on the assumption that only those customers being asked to pay would suffer the consequences of a HILP event, which is simply not the case. A HILP event in the centre of a major city would also have a negative financial impact on both business and residential customers, not only within the city but also in the surrounding areas, with knock-on effects on the British economy as a whole.

Chapter 5

Financial Issues

As well as answering the questions in the policy consultation document we have also outlined our views below on the key financial issues for DPCR5.

5.1 Cost of capital

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

Our overriding views on the cost of capital and the appropriate methodology haven't changed as a result of the current turmoil. The cost of capital for DPCR5 should support the ongoing need for investment.

These overriding views are:

- Financing risk is best managed by DNOs and not customers.
- The cost of capital should support the need for investment in networks and reflect the risk of the current investment cycle.
- The cost of capital should support sustainable financial structures capable of funding an ongoing need for cash over a prolonged period.

The importance of setting an appropriate rate has never been more important than it is for DPCR5. Given the significant increases in investment programmes anticipated in DPCR5 and beyond, it is essential that an appropriate cost of capital is set to encourage both debt and equity investment. This will ensure that investors continue to have the confidence to fund much needed investment to renew the UK's distribution network, at a time when significant financial uncertainty remains. It is important that good levels of equity are encouraged; this will provide stable and sustainable financing structures which are important in delivering significant investment over the next 15-20 years through changing economic cycles.

The current economic difficulties pose a number of issues for DNOs and Ofgem in setting the cost of capital for DPCR5:

The need to invest	The need for substantially increased network investment for DPCR5 means DNOs are likely to have new debt and equity requirements
Access to debt	Access to debt markets is difficult and recent evidence suggests that the issue of new debt in the current climate is done so at a premium

Risk of low cost of capital	Current volatility means that using only long term data as a basis of the cost of capital will lead to a cost of capital that is too low to enable DNOs to raise the increased finance required for DPRC5.
Attracting equity investment	On current forecasts, DNOs will be cash negative for 15-20 years with significant cash returns locked into the growing RAV value. The framework therefore should be sufficiently attractive to the equity investor to take this long term view.

5.1.1 Indexing

In respect of indexing, our view continues to be that it is not appropriate to index the cost of debt and we welcome the position on this laid out in the policy paper. We believe that regulation should be simple and lay risk where it is best placed to be managed. Including a form of indexation within the allowance is contrary to this:

Transfer of risk from DNOs to customers	We believe that DNOs, not customers, are best placed to manage the risk on the cost of debt.
Practical problems	The cost of debt is not strictly observable, no clear benchmark exists. Setting an indexation could lead DNOs to arrange their financing in line with whatever benchmark Ofgem uses, which will not necessarily be the most efficient.
Determining finance structures	Ofgem should be wary of utilising specific instruments which may discriminate in favour of or against any one model. It is the responsibility of DNOs to determine their own financing structures, e.g. the balance of fixed and floating debt.

5.1.2 Methodology

We support the maintenance of the post-tax approach to the cost of capital requiring the tax allowance to be calculated separately.

We agree that a calculation methodology based on long term trends is a strong tool in determining the cost of capital and we encourage Ofgem to ensure that the measures used within the calculation are robust. For example, we do not support the use of index linked debt as a measure of the risk free rate due to the level of bias in the rate caused by factors such as pension legislation.

We also feel that in order to set a cost of capital that recognises the urgent need for investment today, recognition should be given to shorter term data that reflects current market conditions. UK distribution networks need investment now and for the next 15 to 20 years, and the cost of capital should reflect this. In order to achieve this any analysis of the appropriate cost of capital should recognise:

- the importance of maintaining a strong credit rating (A3/A-) to ensure ongoing financeability;

- the cost of debt seen during recent years is no longer available. Any shift back to 'normal' is expected to be at a higher level;
- the level of risk inherent within the price control, including the risk from the cash cycle that arises from periods of increased investment.

5.1.3 Reopener/Trigger

As discussed, current economic conditions present problems in setting the cost of capital. It is not possible to understand what the time and scale of the current economic downturn and market conditions will be and how any subsequent recovery will manifest itself. These conditions indicate that the potential for either a reopener or trigger around the cost of capital may be appropriate to offer some protection for both customers and DNOs against significant future volatility. We still think that overall financial risk is best managed by DNOs and so would expect any mechanism to be symmetrical and to offer protection from material changes within the cost of capital.

We agree with your view expressed in the paper, the decisions around the cost of capital are best revisited during the latter half of 2009. Despite this, earlier discussion of the main principles and methodologies is vital to allow for full discussion and consultation.

5.2 Pensions

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

We welcome the recognition in the policy paper that the difference in valuation dates across DNOs could lead to inequitable pension allowances, in particular having a detrimental effect on cash flows. The high level of external influence on pension costs, which has increased during DPCR4, supports the pass through treatment.

Consistent with the views we expressed in our response to the pensions consultation, we support the second of the three options presented in the policy paper (Appendix 10 1.13):

> *"base the pension allowance on DNOs' assessments of their pension costs over DPCR5, which would be supported by work from the scheme actuaries and subject to Ofgem review for reasonableness"*

This ex ante approach is consistent with the treatment of other cost areas of the price control. The funding implications of ex post adjustments would be significant, with DNOs required to fund pension deficits from already constrained cash resources.

As stated in Ofgem's policy paper, DNO pension costs are forecast to be £1.3bn during DPCR4 and £1.5bn during DPCR5. These costs are significant and we understand Ofgem need to consider whether the pension principles are working, the steps that DNOs have taken to ensure costs are efficient and the appropriate treatment of pension costs in DPCR5.

In response to this we think it is also worth taking time to evaluate those factors that are driving pension costs, the level of influence that DNOs have on these and therefore the support that this gives to the pass through arrangements currently in place for DPCR4 and proposed for DPCR5. We support the comments made that there are a number of inbuilt protections within the pension costs of DNOs and this level of

protection has increased since the previous price control. The weight of these influences and the developments in the UK pension environment since DPCR4 was agreed should provide more, not less, comfort that the current arrangements are appropriate.

5.2.1 Influences on Pension Costs

Deficits are driven by external factors	
Mortality rates	Mortality rates have been one of the key drivers of pension scheme liabilities, a factor beyond the control of the DNOs.
Capital Markets/Investment performance	Two factors outside of DNOs control affect the investment performance and liabilities of schemes, firstly the performance of the market and interest rates which are external to the DNO and the pension scheme. Secondly, it is the responsibility of the trustees to determine investment strategy, not the company.
Payments are influenced by external independent bodies	
Trustee influence	Trustees are independent and have specific responsibilities. It is the role of pension scheme trustees to put in place recovery plans to address any funding shortfalls and to decide upon the scheme's investment strategy. Trustees must act impartially, in the best interests of scheme beneficiaries, and should not be influenced by the employer. Ofgem must understand that trustees are independent of the company, and that the objectives of trustees are not necessarily the same as Ofgem's or the company's. Although done in consultation with the company, it is ultimately the trustees who make the key decisions which influence pension costs.
The Pensions Regulator	The objectives of the Pensions Regulator are to protect the pension scheme members' benefits and reduce compensation claims from the PPF. Its recommendations therefore focus on early repayment of pension deficits. Although pension deficit payments are not explicitly agreed with the Pensions Regulator they do have powers to serve contribution notices where plans are unduly long or end loaded.
Competitive pressures	As with a number of other DNOs, Central Networks' pension scheme is part of a larger E.ON UK scheme incorporating both regulated and non-regulated businesses. Any pension costs borne by Central Networks are a minority share of the E.ON UK group's costs with any pension decisions being made in the context of a competitive market. E.ON UK has an extremely strong incentive to manage the costs of its pension scheme efficiently, given that only a small proportion of these are

	passed on to customers of the distribution business and shareholders must fund the rest. The E.ON UK defined benefit scheme is closed to new members.
Historic positions affect costs significantly	
Legal protection	We estimate that, of the defined benefit scheme members attributable to Central Networks, over 90% are Protected Persons under the Electricity Act and these provisions can only be changed with a change to primary legislation.
Number of pensioners vs. actives	Ofgem should also consider how little network operators are able to influence pension costs given the large proportion of retired and deferred members compared to active members of defined benefit schemes and the legal protection over many of these. We estimate that, of the defined benefit scheme members attributable to Central Networks, only approximately 13% are currently employed by the company and over 90% are Protected Persons under the Electricity Act.

5.2.2 Deficit Recovery Periods

We do not consider it necessary to adjust the deficit recovery periods to be generic rather than specific. The additional level of complexity to the price control does not offer anything for consumers given the level of external influence on funding costs and payment profiles discussed above.

This profile is set through consultation between the trustees and the company, with trustees clearly wishing for deficits to be repaired as early as possible, under the guidance of the Pensions Regulator. The Pensions Regulator will scrutinise deficit recovery plans and could issue a contribution notice if it believes the deficit repayment plan to be unduly long or back loaded. It is important that Ofgem understands that the Pensions Regulator does not set 10 years as an acceptable maximum, rather this is a trigger point for it to review pension deficit repair plans and Ofgem should certainly not consider a funding period at this extreme end of the range of acceptability.

5.2.3 Tax

We support the consistent message, as detailed in the initial consultation, that Ofgem intends to maintain the setting of tax cost allowances on an ex-ante basis with an ex-post adjustment where actual gearing exceeds the gearing assumed within the cost of capital.

5.2.4 Trigger Mechanism

With regard to trigger mechanisms, our overall view is that DNOs should be able to manage the ongoing risk themselves and the number of ex post adjustments should be minimised to avoid undue complexity within the price control. Any ex post adjustments for changes in the tax regime are only appropriate for changes that are material in nature and outside of the control of DNOs, including changes in:

- Legislation

- Tax Case law
- Published HMRC guidance
- Accounting Standards

Any mechanism should be symmetric. We support the view in the policy paper that the automatic pass through of any changes in tax costs is not appropriate.

5.2.5 Modeling of Capital Allowances

The policy paper sets out three distinct options for the allocation of expenditure into the various tax pools: the generic, common and specific approach, and Ofgem states a preference to revise the methodology to follow the common approach.

Our own view is that a specific approach is preferable, given that the calculation of deferred revenue expenditure should mirror depreciation policy it is more appropriate to adopt DNOs' actual capital allowance policies and allocations when modelling the tax allowance. There is sufficient detailed information available to Ofgem to enable DNO specific allocations to be calculated.

Chapter 6

Process and Timetable

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

We provided Ofgem with our response to this question prior to the submission of this document.

Question 2: We invite views on our proposed process.

Overall we are in agreement with the timetable and detailed process as contained within the policy paper. However we feel there are certain aspects of the process that could be improved.

We understand the rationale behind Ofgem's proposal not to publish an updated proposals document in September. We also recognise that the timetable is later than previous price controls with a potential risk of issues of accuracy and policy remaining outstanding ahead of the final proposals. Therefore in order to manage this engagement, remove uncertainty and maintain transparency we suggest that Ofgem provides greater transparency of progress via the cost review working groups to clarify changed thinking and revised performance targets.

In the current uncertain climate Ofgem needs to be mindful that significant changes that may have a bearing on our forecasts are not restricted to the macro-economy, but extend into other areas of uncertainty e.g. distributed generation and availability of finance. In order to achieve a settlement which allows DNOs to provide the best possible service to customers and fulfil asset management responsibilities, we should be able to update our plans in these areas.

The Consumer First programme has shown itself to be a strong part of Ofgem's stakeholder engagement process, and we hope that consultation with the Consumer Challenge Group will ensure that the future of distribution policy will be focused around the needs of customers. However, we feel that the areas which the Group examine should be extended to consider the future role of networks and the impact that this will have on customers. We would appreciate the opportunity to meet the Consumer Challenge Group, and to discuss their areas of interest.

We feel that working groups are proving to be a valuable tool for sharing ideas and developing policy for DPCR5. We would find it useful if Ofgem made clear how it plans to use the working groups to influence the decision-making process.