Electricity Distribution Price Control Review Policy paper - Supplementary appendices

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Target audience: Consumers and their representatives, distribution network operators (DNOs), independent distribution network operators (IDNOs), owners and operators of distributed energy schemes, transmission owners, generators, electricity suppliers and any other interested parties.

Overview: Ofgem regulates the 14 DNOs, who are all regional monopolies to protect the interests of current and future consumers. We set a price control every five years. This sets the total revenues that each DNO can collect from customers at a level that allows an efficient business to finance their activities. We also place incentives on DNOs to innovate and find more efficient ways to provide an appropriate level of network capacity, security, reliability and quality of service.

The current price control expires on 31 March 2010 and Ofgem is now undertaking a Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. This is the second document in the review. We have set out for consultation our views on the overall approach to setting the new control, the methodologies we propose to use, the structure of incentives and the new regulatory arrangements that we think are appropriate. One of the key themes for this review is to ensure that the price control allows the DNOs to play a full role in tackling climate change. This is the last broad ranging consultation before we publish our initial proposals on each company's revenue requirements in the summer of 2009.

This document contains the appendices for the policy paper.

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Context

In March 2008 we published our initial consultation document for the current distribution price control review (DPCR5). The document focussed on three key themes, the environment, customers and networks. Since March it has become even clearer that climate change will be a significant and important factor for DPCR5. The Energy Act 2008, Climate Change Act 2008 and the Planning and Energy Act 2008 are all now on the statute book and serve to reinforce the Government's commitment to meeting targets for carbon reduction.

Following the publication of the initial consultation document we have published our annual connections industry review which raised a number of issues regarding the level and effectiveness of competition in connections and the service received by customers seeking an electricity connection. We have also been working to move the industry towards more cost reflective tariffs, that amongst other things, reward distributed generation that provides a network benefit through deferring the need for further network investment. In addition, we have published our final Long-term Energy Network Scenarios (LENS) report that sets out a range of plausible electricity network scenarios for Great Britain for 2050 and suggests that the move to a low carbon economy could have profound implications for our energy networks.

In August 2008 the DNOs submitted their initial business plans for the DPCR5 period which suggest the industry is looking for a substantial increase in revenues. We have reviewed these plans and visited each of the DNOs in order to understand the basis of the regulatory reporting pack (RRP) data submitted for 2007-08. We will publish our annual RRP report and our quality of service report in December 2008.

This review is taking place against a background of an economic downturn and great uncertainty particularly in the financial markets. This is not an immediate issue but we are aware that as we firm up our proposals during 2009 we will need to take account of these issues and any further developments.

Associated Documents

- Electricity distribution price control review - Policy paper (159/08)
- Update letter on the DPCR5 process (151/08)
- Electricity distribution price control review. Initial consultation document (32/08)
- DPCR5 - looking ahead an initial consultation letter (119/07)
- Consumer First Research for DPCR5 Quantitative Findings (106/08)
- Connections industry review 2007-08 (143/08)
- Long-term Electricity Network Scenarios (LENS) - final report (157/08)

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Appendix 5 – Summary of responses to the initial consultation document

Environment

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

1.1. Overall, respondents seemed to recognise that there was a need for the role of the DNOs to change in order to allow sustainable development and encouragement of distributed generation (DG).

1.2. A number of respondents suggested that a mix of evolution and revolution was necessary to allow an evolutionary approach to delivering revolutionary change, with additional incentives to encourage delivery of this change. One respondent suggested that the efficient development of networks was an evolutionary issue, while new incentives for accommodating DG in the longer term were more revolutionary. Similarly, another suggested that DNOs needed to evolve to meet new challenges but that revolutionary change may be required to the regulatory framework in order to speed up this process. It was also suggested that the regulatory framework needed to be flexible enough to allow considerable evolution.

1.3. One customer suggested that radical change was appropriate as DNOs are slow to improve as they do not feel competitive pressure. One respondent also suggested that revolutionary change was required to the DNO mindset to become more proactive, while another suggested that the nature of change would depend on both the ability and the willingness of DNOs to adapt.

1.4. A respondent outlined that it was generally supportive of an expanded role for DNOs, but that additional incentives would be required. Three DNOs suggested that revolutionary change may be required in the longer term to actively tackle issues such as DG and sustainable development but that deployment should be evolutionary, consistent and promote stability. One DNO did not envisage the need for substantial change until a 'critical mass' of DG was reached, and that this was unlikely during DPCR5. It suggested that regulatory tools be used to deal with uncertainty.

1.5. Another DNO suggested that quick evolution was needed and that the focus for delivery should be investing in recruitment, training, and research and development (R&D). One DNO suggested that stakeholder engagement should be used to consider revolutionary concepts.

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

1.6. Most respondents felt that all key areas had been identified but suggestions for further areas to consider in DPCR5 are presented below.

- Respondents felt that more attention needs to be given to the losses incentive. This can be done by Ofgem who could consider sharpening the incentive by basing it on the shadow price of carbon,
- DNOs suggested they have a role in supporting the transition to a low carbon economy by facilitating DG connections, offering energy efficiency advice and reducing their carbon footprint both at their premises and from their fleet. DNOs however did feel that to do this the DG incentive should be strengthened if they are to be more active,
- DNOs felt they are in a unique position and have skills to move to a DG power flow model. DNOs can play a role in connecting and integrating new energy sources, integrating storage and heat schemes and using energy efficiency initiatives such as demand side management (DSM) and active network management (ANM),
- One DNO thought that the document should have included waste management - to which networks significantly contribute. This includes CO_2 from transport; waste from buildings; waste from street works; waste from offices and depots and waste to landfill,
- One DNO suggested that DNOs are already engaged in carbon footprint reduction and could be more involved in non-carbon issues such as fluid filled cables, undergrounding and floor protection,
- One respondent wanted to ensure that deployment of innovation follows R&D. The registered power zone initiative (RPZ) should allow for the same technology to be used in more than one area/location.

1.7. One respondent felt that connection pricing and locational pricing are inappropriate for DG. They support a national standard connection agreement for small scale DG and the provision of simple, concise, user-friendly guidance. A standard national connection process should be urgently set up.

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

1.8. One DNO suggested that Ofgem influences and should continue to influence works of key industry groups such as the Distribution Code Review Panel and the Distribution Charging Methodologies Forum (DCMF).

1.9. Half of the respondents felt that there should be a more standardised connection agreement and process. This will lead to a clearer understanding of both the DNOs' and DG operators' role in reducing the barriers associated with its complexity. It can also aide sharing of best practice and efficient business process.

1.10. Most respondents felt that working groups would be particularly useful in providing:

- Focus on common components rather than end-to-end process, so that operations can be organised so as to reflect regional differences,
- Efficient regulation helped by delivery at least cost (provided the right agenda is set), but there is a risk that vested interests in maintaining the status quo may inhibit the process,
- Actions and objectives, provided that timescales can be enforced if DNOs do not deliver, and
- An appropriate forum to develop solutions for DG, etc.

1.11. One DNO however did feel that they are already attending several working groups that are examining the perceived issues.

1.12. Two respondents felt that a DNO group with representation from DG developers would be useful to review the Electricity Networks Association's (ENA) engineering recommendations numbers G59[1] and G75[2]. Although one DNO felt that they were already engaged with a review of G59 and G75 and would like to just continue this process.

1.13. Most respondents felt that a review of the DG incentive is needed as part of a wider review of changing the framework to distributed energy (DE). Ofgem may need to consider more radical innovative approaches to support DE.

1.14. One DNO felt that Ofgem needs to set up an independent arbitration process to consider all factors and impacts on transmission from DG.

1.15. One respondent felt that it is essential that Ofgem makes sure any commercial gains are returned to those that have delivered the benefits. Otherwise the situation

[1] G59 - Recommendations for the connection of embedded generating plant to the Regional Electricity Companies' distribution systems.

[2] G75 - Recommendations for the connection of embedded generating plant to public distribution networks above 20kV or with outputs over 5MW.

will remain where it is not cost effective for suppliers to register microgeneration export within the industry's settlement arrangements.

1.16. Three respondents, including two DNOs, recommended that the critical issues that need to be resolved by Ofgem are planning consent and (especially in Scotland) transmission access. This will help to remove the barriers for DG connections which DNOs assessed as not their fault.

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

1.17. Most respondents felt that stronger financial incentives were needed. They also agreed with the areas that have been identified: losses, energy efficiency initiatives, Sulphur Hexafluoride (SF6) leaks, oil leaks, undergrounding and business carbon footprint.

1.18. One respondent felt that it was important that incentives reflected environmental costs.

1.19. One respondent commented that any SF6 emissions targets/incentive should take into account the increasing volume of SF6 used due to replacement of ageing oil/air insulated switchgears.

1.20. DNOs felt that an incentive scheme on losses should be retained but that the present one should be reviewed. The incentive on losses should not only promote asset replacement, but also incentivise efficient use of the network. It was also felt losses must be left separate from the business carbon footprint.

1.21. One DNO suggested that although the incentives may be appropriate, Ofgem needs to develop a measurement system that correctly quantifies DNOs' actions.

1.22. Two respondents supported improving the network and services for connection of small scale renewable generation. They felt that there was far more scope for carbon savings from connections of renewable DG.

1.23. One respondent felt that as DNOs had significantly reduced their greenhouse gas (GHG) emissions, there appears to be no need for incentives. One DNO felt that it was possible to use the discretionary reward scheme for some areas instead of incentives.

How can the long term development statement (LTDS) be made more useful for DG and other users of the network?

1.24. Two respondents felt that early and accurate knowledge of DNOs' plans allow manufacturers to better plan production, labour and material resources. An example would be to use this information to communicate to manufacturers the DNOs' capital investment plans. This will make it possible to benchmark DNOs' activities on the principles set out in the LTDSs.

1.25. Two respondents felt that this information should be made more easily accessible and more disaggregated. Published statements could be supplemented by a web based tool that enables the view of asset utilization and key flows across the network. DNOs should explore how to link these web applications with the connection process. One DNO suggested that this access should be through a single point to all DNO LTDSs which could be run through an independent provider. This would streamline the process since data is often already out of date at the time of publication.

1.26. However most DNOs were apprehensive about implementing online LTDSs wondering whether it would be effective and valued by users. One DNO was concerned that such tools may provide an inaccurate indication of costs and technical issues. They felt that there could be greater benefits from detailed analysis of opportunities to connect DG. Another DNO was also concerned about online availability to anyone and would prefer direct communications with interested parties. Costs were mentioned by three DNOs who felt that if online development was taken forward funding should be made available.

1.27. DNOs suggested that potential customers prefer talking directly to the DNO to identify likely connection points. Given the nature of the electricity industry, developers need to engage with DNOs more to fully assess connection possibilities.

1.28. Respondents felt that for the LTDS to be useful it needed to include all the information in one document. This includes published information from the extremely high voltage (EHV) charging model to provide geographic investment guidance and cost.

1.29. One respondent felt that there was often a lack of understanding regarding the information available and how to use it. A trade association flyer could help better understanding. There was also a call from other respondents to offer free advice to developers which could include where/what capacity might be introduced.

1.30. One respondent felt that commercially available connection costing tools should be made available and funding would allow DNOs to purchase these tools and make them freely available to developers.

1.31. One respondent wanted there to be a consultation with relevant stakeholders. This would assist the development of new initiatives to improve the scope and quality of the LTDS.

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

1.32. Two DNOs felt that there were not any regulatory framework constraints and did not feel anything needed to be done.

1.33. Other DNOs and most respondents felt that there were constraints and offered the following improvements:

- Review use of system (UoS) charging methodology; ensure cost-reflective charging to DG and remove the separate generation and distribution revenue pots,
- Rebuilding of skills is now required to flexibly address the shortage experienced by the DG community,
- An R&D incentive is required to help develop skills and gain operational experience,
- The reactive power framework is ineffective; an alternative is to incentivise DNOs to trade-off investments in power-factor correction with other network investments,
- DNOs should be incentivised to procure the most efficient or minimum-standard equipment at the time of purchase,
- An evolution of the current information quality incentive (IQI) for capex efficiency,
- Ring-fenced funding through extending the innovation funding incentive (IFI).

1.34. Two DNOs felt that the current DG funding mechanism needs to evolve into a proper DG incentive mechanism. They felt that more could be done to strengthen the DG incentive and reward demand-side solutions.

1.35. One respondent felt that greater clarity on connection arrangements would help, especially going forward with commercial arrangements for connecting DG and microgeneration.

Other issues

DG incentive

1.36. There were mixed views on the DG incentive: some of the respondents considered that it is in principle viable but others held that at present the amounts involved have been very limited, since many DG connections have no triggered reinforcement.

Active network management

1.37. The majority of respondents supported the continuation of the IFI and RPZ schemes. They considered that IFI was successful in encouraging R&D, but some argued that the limit on the annual allowance (0.5 per cent of revenue) should be reviewed.

1.38. Respondents favoured the extension of RPZ to include legacy generation and demand connections, as well as DSM initiatives. Some respondents also advocated that RPZ should allow for repetition of deployments to other areas. Some DNOs clarified that the limited uptake of RPZ was not due to lack of support but to the low level of new DG connections and difficulties in getting customer support.

1.39. Several respondents acknowledged that, under the current framework, DNOs are incentivised to favour capex over opex, and that this should be revisited in order to favour non-network solutions.

Roles and responsibilities

1.40. Several respondents considered that in the future (beyond DPCR5, according to some responses) DNOs could have a primary role to play as DG facilitators and recognised that the key issues should start to be addressed now.

1.41. Some respondents considered that the outcome of the Transmission Access Review will influence the future roles of the DNOs and suppliers in their interactions with the GB System Operator.

Commercial issues

1.42. Mixed views emerged on the introduction of revised generator distribution use of system charges (GDUoS) charging arrangements for DG who connected or received a connection offer before April 2005 under a 'deep' connection policy. Some respondents questioned the rationale, the legal implications and the practical feasibility of this option. Other respondents considered it appropriate that all DG should be facing the same charging framework in the longer term and considered it feasible to implement. One respondent argued that introduction of a cost-reflective charging methodology and a single price control is a pre-condition for this option.

1.43. A minority of respondents requested a review of the connection boundary to a 'shallow' position.

Heat networks

1.44. Several respondents acknowledged that DNOs are well placed to play a role in promoting heat networks, for example by giving advice to local authorities and developers as well as by providing innovative connection solutions.

Energy efficiency

1.45. Respondents widely recognised that the current 'supplier hub' model leaves limited scope for DNOs role, and none of the respondents suggested that this is not appropriate going forward. They felt that DNOs could play a role in network issues such as peak demand looping and power factor correction.

1.46. A number of respondents argued that the kWh revenue driver is inappropriate, and that it would penalise DNOs that actively promote energy efficiency. However only a few responses suggested alternative solutions, which included no protection over volume uncertainty or maintaining customer numbers as a proxy. One respondent considered that the major concern about cost uncertainty is from load shifting between parts of the network rather than demand growth.

Metering

1.47. There were mixed views on this. Some respondents considered that smart metering should be implemented by the suppliers. Other respondents suggested DNOs should be more involved in policy discussion. Several respondents considered that the risk of stranded assets should be given particular consideration, to avoid cost uncertainties on DNOs.

Reactive power

1.48. Some respondents considered that DNOs could be well placed to give power factor correction advice and should be enabled to do so. Other respondents considered that economic signals in UoS charges are appropriate.

Losses

1.49. Several respondents agreed that the current incentive framework has proved successful in reducing commercial losses. However several respondents argued that it has provided limited stimulus for investments aimed at reducing technical losses, mainly because of the insufficient strength of the incentive rate and of volatility in settlement data is currently masking benefits from technical initiatives.

1.50. Generally respondents supported the continuation of a mechanism that targets both commercial and technical losses, given economic and environmental benefits. Several respondents suggested potential alternatives, which included the use of input or quasi-output mechanisms, or modelling a reference network.

DNO business carbon footprint

1.51. Several respondents acknowledged that it is important that DNOs are incentivised to reduce their carbon footprint, but some of them also expressed concerns about the low materiality of emissions other than losses.

1.52. Some respondents considered that the most proportionate approach would be to target specific emissions, such as SF6, and that losses should be dealt with separately. One respondent suggested building on the Department for Environment, Food and Rural Affairs' (Defra) Carbon Reduction Commitment (CRC) scheme while another argued that an incentive based on the existing quality of service mechanism could be viable.

Emissions

1.53. A number of respondents considered that it is important to tackle SF6 emissions. It was also recognised that there is a narrower scope for DNO actions as compared to the transmission network, since there are no economically viable technical alternatives to SF6.

1.54. Some respondents commented on fluid-filled cables (FFCs) and considered that an incentive to reduce oil leakage could be appropriate. Some respondents argued that it should focus on sensitive areas only, whilst others considered that a risk-based approach to FFCs operation and replacement, such as the current approach under the joint Environment Agency (EA) and ENA operating code, is an appropriate way forward.

Undergrounding

1.55. The majority of respondents that commented on undergrounding supported the continuation of the scheme and welcomed early commitment to this. The general view is that the project is currently underfunded and that cost caps need to be reviewed and made more flexible.

1.56. There was no support for the extension of the scheme to other areas, although a minority of respondents suggested including lines that are outside but clearly visible from Areas of Outstanding National Beauty (AONB) or National Parks (NPs).

Customers

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

1.57. DNOs generally considered that the current arrangements work well and that this is evidenced by scores under the telephony scheme and performance under the guaranteed standards. They did however recognise the need for increased focus on worst served customers and some refinements to the telephony scheme, guaranteed standards and the connections arrangements.

1.58. There was general support for the continuation of the information incentive scheme (IIS) and the target setting methodology from DPCR4.

1.59. Some respondents emphasised the importance of the DNOs' stakeholder engagement process in determining expected service levels.

1.60. One DNO believes that the current regulatory arrangement should be reconfigured to better reflect customers' shifting priorities towards more direct customer service issues such as better communication, quick response to their questions, the environmental performance of their supply and its impact on CO_2 emissions.

1.61. Respondents considered that the regulatory arrangements did not produce the level of service expected especially regarding connections and worst served customers. Respondents considered that there is not enough uniformity in customer service levels across the country and expressed concerns about DNOs seemingly operating in isolation.

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

1.62. DNOs agreed that the current arrangements are correct but suggested the gaps that need to be addressed are:

- Worst served customers: Most DNOs supported a scheme with a specific allowance over an incentive based approach,
- Target setting: DNOs suggested a number of refinements to the benchmarking process,

- Guaranteed standards: Most DNOs suggested the need for capped exposure under the normal guaranteed standards (EGS2[3]).

1.63. One respondent considered that there should be more focus on improving rural networks.

1.64. Another respondent considered the establishment of the Consumer Challenge Panel should assist in identifying areas for change, suggesting improvements and highlighting best practice.

1.65. Respondents would like to see a uniform process for connection application and universal connections quotes and suggested that additional standards and incentives to improve connections services are necessary.

Are DNOs customer focussed enough or should they be doing more to improve communication with customers?

1.66. Some DNOs considered that the customer service reward scheme, stakeholder engagement, consumer research and the new low carbon economy provides customer focus. DNOs suggested the following areas of focus could be improved:

- Telephony – including objective measures within the incentive,
- Customer information – use of live network information and short message service (SMS) messaging,
- Broader customer satisfaction measure – developing a measure focused on wider aspects of customer service.

1.67. Other respondents agreed that better quality information was needed from DNOs with increased channels for feedback particularly with regard to restoration times and network investment. One respondent suggested that the telephony scheme should be refocused to incentivise a personal response to calls and that a consumer panel and stakeholder engagement will provide improved customer focus.

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

1.68. Most DNOs considered that their financial exposure was set at the right level and did not support financial exposure for IIS being increased. They proposed that a cap or exclusion mechanism should be introduced to exclude certain categories of exceptional events.

[3] Restore supply after a fault: During normal weather

1.69. Some DNOs considered that the balance across the incentives needs to change. They suggested that reducing the exposure to customer interruptions (CIs) and customer minutes lost (CMLs), expanding the customer service target and possibly adding a non-losses environmental target would help. They also suggested that given the uncertainty around target setting and exceptional events, they could not support the equalisation of incentive rates across DNOs.

1.70. Most DNOs raised concerns with uncapped guaranteed standards. They were concerned that their upper exposure to guaranteed standards payments during one-off exceptional events is unlimited under the DPCR4 incentive mechanism and considered that alignment with weather related events is required to provide a reasonable level of exposure.

1.71. One respondent thought that guaranteed standards exposure should be extended to cover timescales and compensation levels for resolving complaints and that the present arrangements do not place an incentive on the DNOs to address the issue that caused the failure.

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

1.72. Most respondents indicated that the right issues and appropriate areas had been identified and welcomed the focus on worst served customers.

1.73. Most DNOs did not support a move towards incentivising short interruptions within the incentive scheme.

1.74. One DNO considered that allowances for training should have been identified as an issue as the same labour shortage issue is apparent in electricity as in gas and needs to be reviewed.

1.75. Some DNOs considered that the thresholds for exceptional events needs to be examined carefully and revised due to the change in national weather conditions. They also suggested that the existing mechanism needs to be refined to exclude certain events out of the control of DNOs.

1.76. One respondent supported the focus on worst served customers noting that multi-site business customers should be counted individually within any standard that might be developed. Another respondent focused on rural areas where they suggested consideration should be given to a specific allowance to enable DNOs to consider options for network improvements to these groups of customers.

1.77. Another respondent suggested that extended licence conditions should be considered for connections. They believe that where effective competition exists or is developing successfully, regulatory obligations should be removed or minimised with this being reversed where effective competition is not practical.

1.78. One respondent highlighted concerns with the impact of IIS on the health and safety of DNO employees.

Networks

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

1.79. Two DNOs considered that the key lessons have been captured. These are to improve the incentives faced by DNOs to make efficient investment, remove distortions in the current control, increase the capacity for the price control to reflect the specific business needs, strategies and objectives of each DNO and make best use of the data collected through the annual regulatory reporting packs (RRPs).

1.80. Some respondents felt that in certain cases it is too early to comment on some issues. For example, one DNO supports the use of the IQI in principle, but needs to work with Ofgem on interaction with the submission process, the application to building blocks and design and calibration of the mechanism before providing a detailed reaction. One respondent felt that good progress has been made on the definitions of costs, but that it should be remembered that this is not a finite exercise, as there will always be new perspectives and new information coming to light.

1.81. Most respondents however felt that there were numerous issues still outstanding which are:

- The definition of business costs (includes costs which are network driven) and concerns that increased capex will have a bearing on other costs,
- Concern about the amount of technical resource Ofgem retains in-house, and are whether Ofgem has appointed consultants,
- The composite scale variable (CSV) did not reflect the main cost drivers for DNOs; in particular, it did not capture the indirect costs of delivering large capex programmes, nor did it capture the costs of operating a busy connections business,
- The controllable cost benchmarking was only based on one year’s data,
- There was no meaningful bottom-up analysis, and what was done was not used,
- Ofgem made unsubstantiated assertions about future frontier shift,
- Allowances for regional costs were inadequate and were not based on the evidence, and

- One respondent felt Ofgem should verify DNOs' availability of resources to deliver capital programmes.

Is our approach to cost assessment appropriate?

1.82. Overall most respondents considered that our approach is based on sound principles and have evolved positively from DPCR4. Some respondents however had the following concerns:

1.83. Most DNOs felt that Ofgem should not cherry pick to create a virtual best of the best DNO that in reality cannot exist due to inherent differences in network characteristics. Bottom-up benchmarking should be balanced by a top down view.

1.84. One DNO felt that it was not clear how Ofgem's benchmarking takes account of the effect of a single DNO skewing analysis to create a false frontier.

1.85. One DNO was concerned with the RRP format and rules which have been subject to frequent change. They felt that historic RRP information only provides a portion of the data required for a BPQ and shows that it is difficult to ensure that systems are aligned to the latest requirements.

1.86. Three DNOs felt there was a need for transparency and clear definitions regarding financial treatment. They require a clear understanding of what costs are to be treated as Operating Costs and what costs are to be treated as RAV additions.

1.87. One DNO felt that the IQI mechanism should be removed from capital expenditure. They felt the use of related parties may contaminate the data used to compare costs by reclassifying indirect costs as direct costs.

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

1.88. General DNOs felt that post privatisation efficiency savings have now been achieved as evidenced by overspending against opex allowances. As a result further reductions in costs are not sustainable and are inconsistent with continuing to deliver improved customer service.

1.89. One respondent stated that as an alternative to cost assessment other output measures should be developed to incentivise changes that benefit customers (such as high impact, low probability (HILP) events) and the environment.

1.90. One respondent believed that data quality is a key issue and that assessments require cross checking.

1.91. One respondent stated that a fundamental change to load related reinforcement costs is required, believing that the current approach based on customer numbers and demand is fundamentally flawed.

1.92. One respondent urged Ofgem to recognise the importance of fixed costs when considering scope for efficiency improvements.

1.93. One respondent believed there is a need to review the use of upper quartile rather than average performance given a growing consensus that further reductions in cost are not sustainable and inconsistent with continuing to deliver service to customers. They suggest using a body of evidence rather than relying on one specific methodology of benchmarking.

How might our approach to benchmarking be improved?

1.94. One respondent applauded Ofgem's use of benchmarking which they believe ensures that DNOs are moving towards best practice. They suggested that this could be extended to include comparisons with other industries.

1.95. Several respondents discussed the merits of international benchmarking and concluded that though this would be of interest the results could be inconclusive due to difficulties in obtaining data on a like for like basis.

1.96. One respondent stated support for the initiative by Ofgem of determining network scale by the development of an asset man-hours driver.

1.97. Some respondents thought that some indirect activities such as policy control centres, transport, IT and property should be reviewed separately whilst other items such as tools and plant should be combined with the direct costs they facilitate.

1.98. One respondent felt that the use of total expenditure (totex) analysis could remove the perceived incentive to outsource capital work rather than find best value.

1.99. Another respondent felt there is a need to recognise when opex expenditure can significantly extend asset life and defer capex. They suggested that this expenditure should be recognised as quasi capex.

1.100. One respondent was concerned that the benchmarking of costs should not mask the need to deliver customer service which may not be the least cost option.

1.101. One DNO stated that Ofgem's approach to reconciliation of top-down and bottom-up methodologies needs to be developed with the industry early in the process so that the setting of allowances is transparent and can be cross-checked.

1.102. One DNO felt that there is a need to discuss normalisation of costs particularly in relation to labour rates. They thought it was a better approach to make a specific adjustment to the allowed costs where there is clear evidence that a licensee suffers, unavoidably, from high costs associated with its unique circumstances.

1.103. One respondent believed that bottom-up approach tends to capture differences in cost allocations due to different business processes despite robust rules.

1.104. One respondent suggested that benchmarking could be improved to demonstrate asset stewardship by providing transparency of capital investment and comparing asset service compared to design life.

Have we captured all the key issues for networks?

1.105. One respondent suggested that historical benchmarking needs to recognise the effect of input price inflation.

1.106. One respondent questioned the potential impact of smart metering in reducing demand.

1.107. Several respondents highlighted the future skills challenge and the need to provide funding for training and recruitment.

1.108. One respondent suggests that it would be appropriate to use the Long Term Energy Network Scenarios (LENS) project to inform the overall strategic direction for setting allowances through to 2015.

1.109. One respondent stated that there is a need to take account of the potential impact of the economic climate.

1.110. Another respondent stated that there is a need to anticipate the increase in non-load related investment to meet HILP events, DG, active networks, increased resilience and environmental issues.

1.111. One respondent was concerned that network utilisation is an area that needs better understanding, particularly in relation to connection charges for new customers and the impact of high utilisation restricting the ability to reconfigure the network to avoid planned interruptions. They felt that this should be a topic for asset management appraisals.

Is our building block approach to forecasting appropriate?

1.112. All DNOs agreed the building block approach is appropriate. None of the other stakeholders were adverse to this approach. Key comments are summarised below:

- Building blocks cannot be assumed to be wholly discrete,
- The building block approach captures the majority of important DNO cost areas,
- This approach gives the opportunity to identify current needs and future goals for the network so that a case for those requirements can be created with input from stakeholders,
- This approach may lead to undue focus on inputs and engineering at the expense of considering the service to consumers.

What is the scope for developing additional outputs measures and how can these be incorporated into the price control?

1.113. One respondent believed there needs to be balance between commonality and flexibility so as not to stifle innovation.

1.114. Respondents felt that before introducing additional measures which could lead to incentive payments or claw back there is a need to invest in improvements to data quality. Collaboration should then take place to develop appropriate mechanisms to measure new outputs.

1.115. Most respondents also felt that a common theme in response to this question related to asset condition and methods of measuring and reporting this. There was support for the development of a common definition of asset condition to enable comparisons between networks and as the basis of a long term regulatory approach to network investment.

1.116. One respondent was concerned that some networks, due to their inherent situation, may perform poorly in some categories of output and could be unfairly penalised.

1.117. One respondent believed there is scope for greater output measures relating to new connection work which are currently the cause of half of their customer complaints.

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

1.118. Overall, DNOs feedback that they were involving their stakeholders in providing input to their business plans via their websites and that they were using responses from their initial consultation to develop costed options for further discussion with stakeholders at future events.

1.119. One Respondent felt that Ofgem should play a greater role in giving direction and coordinating stakeholder engagement. It was felt that DNOs should take responsibility for the process with Ofgem assessing the style of engagement, diversity of interests canvassed, feedback provided by DNOs on stakeholder impact on business plans. Ofgem could ask stakeholders to provide them with an appraisal of process.

1.120. One DNO felt that there is less value in generic consultation to a wide range of stakeholders covering multiple issues and more value from focussed group discussions. One respondent commented on the inefficiency of all DNOs approaching stakeholders who have a national interest.

1.121. One respondent would like to continue a dialogue with Ofgem about their activities and receive feedback so they can include this in the next round of stakeholder engagement.

1.122. One respondent believed Ofgem should provide more guidance as they perceive a conflict between the DNOs obligations under section 9 of the Electricity Act 1989 and the duties of Ofgem to protect the customer interest and promote competition where appropriate.

1.123. One DNO was concerned that it will be difficult to manage stakeholders' expectations when not all of their wishes can be met.

1.124. One respondent believed that stakeholder engagement should form part of a discretionary reward; another stated that it is a requirement and therefore does not require an incentive.

1.125. Another respondent expressed concern about the accuracy of investment plans and would like to see greater intervention by Ofgem in assessing the plans. They stated that they would also like the plans to extend into the supply chain beyond the DNO, in order to ensure that there are the plans can be delivered.

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

1.126. Respondents viewed these incentives as an essential development of RPI-X regulation. There was general support for the continued use of these incentives to encourage up-front honesty and accuracy in forecasting and ongoing efficiency in delivery. It was felt that modest reforms would encourage DNOs to provide the whole picture and make the right investments efficiently.

1.127. DNOs were concerned regarding the possibility that the mechanism could be recalibrated following initial submissions without DNOs having the opportunity to re-bid.

1.128. One respondent felt IQI was seen as a valuable tool for reducing reliance on the views of Ofgem regarding differences in opinion in assessing future capex needs.

1.129. Respondents felt the current issue and consequences of under spending of capex should be fully considered. In the absence of appropriate output and efficiency measures it is inappropriate for DNOs to under spend their capex allowance. Similarly it is wrong to penalise DNOs who for good reason overspend their capex.

1.130. Most respondents were concerned about whether these incentives have fully addressed the issues of the quality of capex forecasting although respondents felt it was a relatively new incentive that should not be materially altered at this stage. One respondent also felt there was a risk that the capex allowance was still seen as a ‘budget’ to spend up to.

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

1.131. It was felt that a period of stability is required to assess whether the mechanism is working appropriately before making further changes. However consideration should be given to using a similar approach to operating expenditure. The Ofgem December policy paper should include the IQI calibration matrix for review during the 2009 Business Plan Review process. In addition:

1.132. One respondent would in principle support the application of the sliding scale to a network cost block with appropriate capitalisation, but would need to work with Ofgem to better understand the details.

1.133. One respondent believed the IQI did not take account of risk aversion in the industry which led to high forecasting. Asymmetric exposure to over and under spending should be introduced.

1.134. Two respondents believed that currently IQI values Ofgem's or their consultants' estimates above that of the DNO in setting the benchmark. This is contrary to Ofgem's stated wish to put more focus on the DNOs' own plans. The consultants' reports should be available to the DNO.

1.135. One respondent believed the rolling capex incentive is inappropriate as it is not clear whether under spending has arisen due to deferment or improved efficiency.

1.136. One respondent suggested that it may be appropriate to normalise major projects for potential distortions before applying IQI due to their high volatility in cost and timing.

1.137. One respondent stated that the key weakness is that the break-even point for DNOs is not reflective of other comparable models. This point appears to be overly high compared to the menu for the gas price control review set at 5%. Ofgem could consider rewarding DNOs with a higher break-even point if the difference between their initial business plan and Ofgem's assessment is below a certain level, perhaps a ratio below 1.05.

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

1.138. The majority of respondents were in favour of this. There was recognition of the attractiveness of equalising the incentive rates to avoid perverse incentives. However, they advised caution regarding the risk of weakening opex incentives with savings being achieved through inappropriate underspend of capex.

1.139. One respondent said they agreed, if it ensured DNOs carry out the appropriate mix of activities to provide an effective service for customers.

1.140. One respondent believed that business costs driven by direct or indirect network activity should be moved to network costs and capitalised at a higher rate for benchmarking against appropriate drivers.

1.141. One respondent agreed that the trade off between capex, opex and performance is key area to develop; recognising that some companies will have invested heavily in the past whilst others will need greater funding to close the performance gap.

1.142. One respondent suggested that an appropriate approach would be to apply one overarching target to costs traditionally described as capex, opex and indirect. A single symmetrical incentive rate could then be applied to these costs so that a proportion of overspending would be recoverable. Costs subject to more complex revenue drivers associated with DG such as Non Trading Related (NTR) could be treated separately.

1.143. One respondent commented that the incentive to make savings on regulatory asset value (RAV) additions and opex business costs should be equalised.

Is the timetable realistic?

1.144. Respondents felt this is challenging but achievable; it would be beneficial if Ofgem published a more detailed timetable.

1.145. Most respondents felt that Ofgem needs to be clearer with regards to the workgroups it intends to set up as there are important areas of policy development they will need to address. It is unclear how the policies will be developed within the defined timescale, particularly in relation to the role of the DNOs in facilitating development of environmental initiatives.

1.146. One respondent felt that the timetable is realistic but there needs to be more clarity regarding the purpose of quarterly forecast data and how they interact with IQI base case assessment.

1.147. One DNO felt that the timetable for cost work is extremely challenging, especially since the high level business plans are very detailed and will require considerable resources to complete.

1.148. Another DNO commented that the programme is more extensive than in previous reviews.

Financial issues

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

1.149. Most of the DNOs agreed that a traditional approach to calculating the cost of capital should be used. They felt this would ensure consistency and predictability and any incentive mechanisms should be separately constructed.

1.150. One DNO felt that the cost of capital needs to be determined using common generic assumptions for an efficiently managed DNO to ensure that innovation and the development of best practice is not inhibited. Another DNO suggested that an allowed cost of capital around the level seen at DPCR4 should be considered, although others thought that this may compromise future funding.

1.151. The issue of a split cost of capital was mentioned by a number of respondents. One respondent was in favour of a split cost of capital with one rate for the (lower) historic cost of debt and another for the new capital investment reflecting the marginal cost of debt. Three other DNOs however felt a split cost of capital would be detrimental, increasing regulatory risk and undermining investor expectations.

1.152. One DNO felt that given the likely increased investment requirements DPCR5 should facilitate equity injections.

1.153. Two DNOs suggested that DPCR5 should include new risks such as new technology, new environmental incentives and higher risk stemming from higher levels of investment. They felt that Ofgem should recognise the changes in the risk profile of the DNOs and supplement it with appropriate incentives to invest.

1.154. One DNO considered the cost of equity and felt that if gearing levels are changed in DPCR5, the cost of equity should be adjusted accordingly.

1.155. One DNO suggested that other methods used to measure cost of capital should be used as a sense check.

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

1.156. Most respondents were against any additional measures to protect DNOs and felt that DNOs are in the best place to control their debt. Some respondents however did feel that there were some issues as stated below:

- One respondent felt that spend should be absolute, in line with the capex requirements of the network. Any protection should ensure this ability rather than protect the financial performance of the DNO,
- One respondent felt that due to higher levels of uncertainty Ofgem should introduce a cost of debt adjustment mechanism. This could take the form of a re-opener in the event that the actual cost of debt rose materially above the allowed cost of debt (CoD) for a sustained period,
- One DNO suggested that if the cost of debt is set below DNOs' existing fixed-rate debt, an allowance for embedded debt costs should be introduced.

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

1.157. The majority of respondents felt that financeability adjustments should not be needed; otherwise it would show that the original arrangement was incorrect.

1.158. One respondent suggested that if such adjustments led to an overall lower cost of capital, it should be explored.

1.159. One DNO felt that the markets are not used to Ofgem assuming high levels of retained earnings or rights issues and that a blend of financeability adjustments and equity formation incentives might be necessary.

1.160. DNOs argued that accelerated depreciation payments should not be used as compensation for a lower cost of capital. They also argued that there is limited scope to resolve financeability concerns by further adjusting the depreciation profile.

1.161. Three respondents felt that Ofgem needs to protect DNOs by making sure they have sufficient funds to finance their activities. If there are unforeseen circumstances then financeability adjustments should be considered.

1.162. The two Scottish DNOs reach the end of the period of pre vesting depreciation in 2010 and they consider that the same treatment should be applied to them as the other 12 DNOs during DPCR3 and DPCR4 i.e. reduce depreciation life to post vesting asset additions to 20 years with a 15 year smoothing adjustment.

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

1.163. All respondents agreed that it was appropriate for Ofgem to make commitments over the long term although one respondent observed that this must be consistent with its statutory objective to protect the interest of consumers.

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

1.164. Most respondents agreed that a mechanism should be introduced in cases where there has been a change in the corporation tax regime which is outside of a DNO's control.

1.165. One DNO suggested that if the mechanism was to be introduced it must have a clear definition of 'major change' and a clear distinction between changes to the corporation tax regime and tax efficiencies.

1.166. One DNO suggested that the mechanism could be a pass-through of corporation tax costs supplemented by a modest incentive at the margins.

1.167. Another DNO suggested the mechanism could involve bands around the tax component of allowed revenue. An adjustment would then be made if changes in the corporation tax regime impact the tax allowance more or less than a band allows.

1.168. A further DNO suggested that Ofgem should use company specific allocations of capital expenditure to capital allowance pools as we now have historic data and forecasts to match new investment.

1.169. Two respondents however felt that there should not be any ex post adjustments as DNOs should be able to manage this ongoing risk themselves. The tax component of allowed revenue should be provided on an ex ante basis, incentivising companies to manage their tax affairs efficiently thus benefiting consumers.

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

1.170. Most respondents supported the publication of a fully populated financial model as long as DNOs could remove confidential/commercially sensitive data and that the data was consistent across all DNOs.

1.171. One DNO suggested that Ofgem should communicate the purpose of the model and advise on any generic interpretational issues that may arise.

1.172. Another DNO had reservations regarding the usefulness to third parties of providing a model that represents only Ofgem's view of the costs and income.

1.173. One DNO felt that this publication is not useful. It would have to be consistent with stock market rules and could also prejudice efficient procurement by revealing to suppliers the DNO's forecast requirements.

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

1.174. Most respondents agreed that allowed revenues should be profiled to provide stability to customers and be net present value (NPV) neutral.

1.175. One DNO suggested that they were also in favour of using rolling incentive mechanisms in order to dampen any effect on volatility.

1.176. Two respondents felt that the choice of profiling should depend on the likely size of the revenue adjustment in the first year of new price control ('p naught') and financeabilty considerations.

1.177. One respondent felt that it was paramount that the profile of revenue demonstrates that the final price control proposals are based on a financeable plan. This may result in a profile of price changes that requires a step change at the beginning of the next price control.

1.178. Some respondents however feel that securing a revenue settlement that is financeable on an efficient basis should take precedence over smoothing customer charges. They feel that it is not a priority objective and will lead to DNOs needing to justify large variations.

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

1.179. There are many factors that respondents feel need to be taken into account when determining the level of gearing as stated below:

- Most respondents felt that notional gearing similar to that used in DPCR4 would be appropriate as it would maintain regulatory certainty, and
- Respondents have suggested that Ofgem should settle on a gearing assumption that does not promote further moves to a thin-equity model.

1.180. One respondent argued that DNOs can achieve gearing levels of up to 70 per cent whilst maintaining a solid investment grade rating.

1.181. Respondents also suggested the following factors that need to be taken into account:

- Vulnerability of highly geared entities to financial distress and associated risk to customers,
- Need cost of capital (CoC) that is high enough to raise investment grade debt and also equity investment,
- Licence requirement to maintain investment grade credit rating and Ofgem's assessment of comfortably within investment grade,
- Requirement to encourage DNOs to maintain financial flexibility to withstand financial shocks, such as freak weather incidents or the credit crunch, which can be restricted by highly geared models,
- Impact of recent credit crunch on credit rating of entities with highly geared structures,
- Credit agencies are not appropriate to judge such key areas of public interest, and
- Level of gearing assumed should be consistent with a comfortable maintenance of an investment issuer grade credit rating.

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

1.182. Most of the respondents agreed with the proposed treatment as there should not be any encouragement for highly geared structures.

1.183. One DNO suggested that in line with the proposed treatment Ofgem needs to establish a tax managers working group.

1.184. One DNO suggested that Ofgem should consider a pass through of tax costs. If this is adopted, changes in the marginal rate of tax arising from the tax shield should also be captured.

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

1.185. The responses presented no common alternative approaches to calculating RAV; however most felt that RAV did not reflect enterprise value.

1.186. One DNO felt that it would be detrimental to make any major changes in the calculation of RAV additions and that regulatory shocks to investors must be avoided.

1.187. One DNO felt that DNOs had reached a point of diminishing returns for future efficiency programmes. They thought Ofgem should therefore consider allowing non-operational capex to be allowed as part of RAV.

1.188. One DNO felt that the removal of metering assets from the RAV in 2004 increases the risk of asset stranding. They are in favour of Ofgem considering the treatment of legacy meter asset provision (MAP) as part of current review.

1.189. DNOs indicated that they were against interpreting market transactions as indicating that the RAV is not reflective of enterprise values, since recent transactions were based on a variety of factors including possibly overly aggressive assumptions.

Process

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

1.190. Most respondents outlined their broad support for the range of approaches put forward. The majority of DNOs requested the inclusion of some form of September 2009 update.

1.191. One respondent suggested that the increase in stakeholder engagement could result in an increase in stakeholder expectations. They suggested that these would need to be carefully managed. Two respondents requested that details of the stakeholder meetings planned by Ofgem and DNOs be made available as soon as possible.

1.192. One DNO requested that the policy paper be published as early in December 2008 as possible to allow DNOs to consider the document when finalising their forecast business plan questionnaire (FBPQ) returns for January 2009.

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

1.193. Most respondents supported the introduction of a consumer challenge group, although the DNOs stressed that membership needed to be representative. One DNO was opposed to such a group as it would be unlikely to be representative and could undermine the willingness to pay research. Two DNOs suggested that the group should not focus on a single issue while another suggested that the group should understand the willingness to pay research and be unbiased.

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

1.194. One DNO suggested that customers needed to be informed about the price control review. One respondent suggested that Ofgem should contact attendees at DNO stakeholder engagement events to gain feedback and that Ofgem could make use of web based tools as well as workshops. Another respondent suggested direct consultation with their members. One DNO suggested that the value and use of stakeholder engagement throughout DPCR5 should be assessed during the post review lessons learnt exercise.

Do you agree with our approach to publish specific impact assessments for key 'important' decisions?

1.195. Most respondents agreed with the proposal to use specific impact assessments for DPCR5. Two respondents suggested that care needed to be taken in drafting specific impact assessments to provide clarity on assumptions, limitations in scope and the interaction with other proposals/options. One DNO suggested that we needed to take a long term view when completing impact assessments and so consider the impact beyond the DPCR5 period. Another DNO suggested that the cost of carbon should be considered in any IAs.

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

1.196. Three DNOs requested some form of September 2009 update, either in the form of a document or a quantified statement. Three DNOs requested further clarity on the timetable and use of FBPQ data and on the interactions between this data and details of the IQI. Two DNOs suggested detailed timetable planning for licence drafting to ensure a smooth process.

1.197. Other respondents suggested:

- Clarity on the treatment of expenditure in DPCR6 where possible,
- Clarity on activities at a lower level,
- That Ofgem needs to monitor developments on environment and specifically climate change, and
- That Ofgem provide a timetable for the resolution of legacy issues from DPCR4.

Appendix 6 - Environment

1.1. Chapter 2 in the main document sets out our high level policy proposals to address the role that DNOs can play in facilitating activities that have a positive impact on the environment and tackling climate change as well as the actions DNOs can take in reducing their own carbon footprint. This appendix provides more technical detail on specific areas (as referred to in the main document) including national environmental policies, distributed generation (DG), use of system charging and other related issues, losses, further details on the business carbon footprint proposals and undergrounding.

National environmental policies and strategies

1.2. The future uncertainties section of chapter 2 contains a table summarising national environmental policies and the potential impact on the distribution networks. The section below discusses these policies and impacts in more detail and provides references to relevant sources for more information.

UK commitment to EU 2020 renewable targets

1.3. The EU has set a target to source 20 per cent of the EU's energy from renewables by 2020. It has proposed that the UK's contribution to this should be to increase the share of renewables in our energy mix from around 1.5 per cent in 2006 to 15 per cent by 2020. The government issued the UK Renewable Energy Strategy Consultation in June 2008, which outlines one possible scenario to deliver this 15 per cent target, with renewable sources forming 32 per cent of electricity generation (compared to less than five per cent today). It is not known what proportion of this generation will be connected to the distribution networks, but it could require significant additional investment both to connect the generation and to ensure that there is sufficient network capacity to allow its operation. Techniques such as active network management (ANM) may help to contain the need for investments in extra network capacity.

1.4. In addition, the consultation states that the country's ambition has to be to use every unit of energy as efficiently as possible, which may lead to an absolute reduction in energy demand in the longer term. This could slow the necessary expansion of the networks. The DNOs can have a role to play in achieving this objective – for example, by facilitating demand side management (DSM).

1.5. The UK Renewable Energy Strategy Consultation Document can be downloaded from the Department for Business, Enterprise & Regulatory Reform (BERR) Renewable Energy Strategy Consultation website:
http://renewableconsultation.berr.gov.uk/consultation/consultation_summary

Planning targets for local energy for new developments

1.6. The Planning and Energy Act 2008 enables planning authorities to set target percentages for the use of distributed, renewable or low-carbon energy in new developments.

1.7. The Planning Policy Statement on climate change (supplement to PPS 1) confirms what is expected from both regional and local planning authorities on tackling climate change. More information can be found at: http://www.communities.gov.uk/publications/planningandbuilding/ppsclimatechange

1.8. These initiatives should reduce the need for distribution network capacity to serve new developments and may also mean that electricity is generated and exported to the networks from these locations. These developments may be located in urban areas with any excess generation supplying local demand with minimal network losses. There is the potential for any growth in on-site generation to result in a reduction in the need for network investment, especially at higher voltages. However, whether such generation is only supplying its on-site load or exporting electricity to the network it is likely to be highly variable and may require the DNO to use ANM techniques.

Zero carbon homes

1.9. Government published its 'Building a Greener Future' policy statement in July 2007. This policy statement confirms the government's intention for all new homes to be 'zero carbon'[4] from 2016. This will be achieved by a progressive tightening of the energy efficiency building regulations - by 25 per cent in 2010 and by 44 per cent in 2013 - up to the zero carbon target in 2016. This policy could mean that new buildings will either have to have their own renewable generation to satisfy their needs, or to be supplied by a local renewable generator. This would mean that from 2016 DNOs would not experience any demand growth from new residential buildings, reducing the need for investment to increase network capacity. It is possible that the household or local generator may at times produce more electricity than is required and therefore could be exporting to the network. To accommodate this on a wide scale, the DNO will probably need ANM techniques to manage the variations and unpredictability of supply. More information is available at: http://www.communities.gov.uk/planningandbuilding/theenvironment/

1.10. The government has also pledged that all new schools will be zero carbon from 2016, with similar potential impacts.

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[4] To be zero carbon, a home would produce no net carbon emissions resulting from the operation of the dwelling (heating, lighting and energy used by appliances such as TVs and cookers).

Government heat strategy

1.11. The UK Renewable Energy Strategy Consultation includes proposals to introduce a new heat incentive mechanism, such as a Renewable Heat Incentive (akin to a feed-in tariff) or a Renewable Heat Obligation, to provide the financial stimulus for new renewable heat deployment and to address barriers and constraints which limit the potential to increase renewable heat deployment.

1.12. Combined heat and power (CHP) is a fuel-efficient energy technology that, unlike conventional forms of power generation, puts to use the by-product heat that is normally wasted to the environment. Because it often supplies electricity locally, CHP can also avoid transmission and distribution losses.

1.13. In 2000 the government set a new target to achieve at least 10,000 MWe[5] of installed good quality CHP capacity by 2010. In 2004 the Department for Environment, Food and Rural Affairs (Defra) published the government's 'Strategy for CHP to 2010' which contained a full range of measures to support the growth of CHP capacity needed to meet the CHP target.

1.14. Increasing CHP will increase urban DG, although the electricity will not necessarily be a consistent source, since the primary focus will be heat generation. The CHP units will be located where the heat is required, which will probably be in urban locations with high electricity demand density. Having generation close to demand can reduce losses and reduce investment for greater network capacity[6]. However, as above, the intermittent nature of the generation may require ANM techniques to accommodate it. More information can be found at: http://www.defra.gov.uk/environment/climatechange/uk/energy/chp/

Microgeneration feed-in tariffs

1.15. The Energy Act 2008 enables the government to introduce a feed-in tariff for 'small' low carbon and renewable generators (defined as not exceeding 5MW) which will offer them a guaranteed long-term premium price for their power.

1.16. The objective of the tariffs is to encourage individuals, communities and businesses to install low-carbon electricity generators and the government intends that the feed-in tariff will come into force during 2010, after a consultation in the summer 2009.

1.17. As with zero carbon homes, this could mean that some homes become partially or wholly self-sufficient in electricity – reducing the overall demand growth, as seen

[5] At 2007, total installed CHP capacity was 5,500MWe.
[6] It is recognised that such generation can require network investment to address increased fault levels.

by the network, thereby requiring less capacity-related network investment. However, if large volumes of small and microgenerators are at times all exporting electricity the DNO may need ANM techniques to accommodate it.

Domestic smart meters

1.18. Smart meters allow two-way communication between suppliers and their customers' meters, removing the need for meter readings and ensuring accurate, timely bills. Customers can monitor their energy use which should encourage energy efficiency and potentially reduce their energy consumption.

1.19. Following consultations, the government has decided to proceed with smart metering for larger business sites. It is proposing to roll-out smart meters to domestic and small business sites - but the mechanics of the roll-out and the specification of the meters has yet to be decided.

1.20. DSM involves the volume or pattern of electricity consumed by end users being intelligently controlled in some way. This control could be exercised by the electricity supplier as part of a tariff arrangement, directly by the consumer or by the DNO to help manage the operation of the network. DSM could form part of a wider strategy to help reduce overall energy demand consistent with the achievement of the 2020 targets. DSM can also involve managing the times when consumers use electricity to smooth peaks of demand and therefore reduce the amount of peak generation required. Both types of DSM can reduce the need for network investment.

1.21. It should be noted that in order for the DNOs to implement DSM the domestic smart meters will need to have certain technical specifications in terms of data storage, accessibility and potentially the ability to restrict supply.

1.22. More information on the government's policies on smart metering can be found at: http://www.berr.gov.uk/whatwedo/energy/environment/smart-metering/index.html

Electric cars

1.23. The King Review of Low-Carbon Cars concluded that almost complete de-carbonisation of road transport could be possible by 2050, most likely through electric or hydrogen-powered vehicles.

1.24. The government is currently looking at the potential scale, penetration and viability of electricity grid powered vehicles (recharging of electric vehicles or plug-in hybrids, or production of hydrogen by electrolysis). This work will examine the case for further government measures to help accelerate the development and introduction of these vehicles and the associated supporting re-charging infrastructure.

1.25. Electricity demand from transport could have a large impact on total UK power demand although recharging and electrolysis might take place principally at night when demand is lowest. This could potentially increase the overall utilisation of the electricity networks by reducing the day/night demand differential. If electric vehicles could be used as storage devices (see below) as well as off-peak loads this may help manage the increased impact of intermittent renewable generation. However, the establishment of an electric vehicle recharging infrastructure might increase the investment needs of the distribution networks.

1.26. More information on the government's views on sustainable transport can be found at: http://renewableconsultation.berr.gov.uk/consultation/chapter-6/executive-summary/

Electricity storage

1.27. The government recognises that as the proportion of electricity generated from renewable sources increases, and where significant quantities of electricity could be generated at times of low demand, energy storage may become increasingly important. Currently, the only significant energy storage resource on the GB grid is pumped hydro capacity and there are limited sites for new development of this technology. There is therefore significant potential for emerging technologies such as flow batteries, super-capacitors and micro-compressed air energy storage.

1.28. There are a number of innovative ideas under consideration for commercial schemes involving electric vehicles, several of which could have additional benefits in providing electricity storage. For example, electric vehicles could be charged at off-peak times such as overnight when demand is generally low and discharged at peak times. This is commonly known as 'vehicle-to-grid' technology. This load-balancing of the electricity grid could be instigated through preferential charging regimes and smart-charging cards.

1.29. It is uncertain whether significant network investment would be required or avoided with the introduction of electricity storage, however it would require ANM techniques to control the flows of electricity in and out of the device(s).

1.30. Again, more information can be found in the government's renewable energy consultation at:
http://renewableconsultation.berr.gov.uk/consultation/chapter-6/executive-summary/

Information requirements for DG

1.31. This section provides further details on the background to the package of proposals regarding information requirements set out in chapter 2.

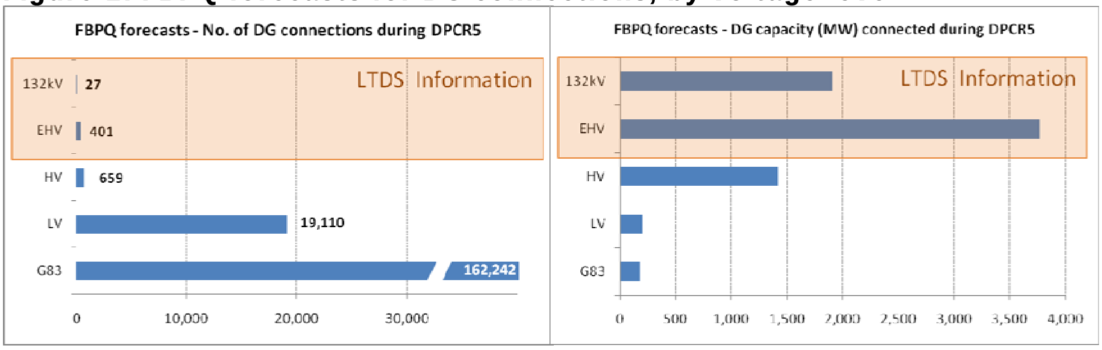
1.32. On 24 October 2008 we held a multi-stakeholder workshop, where DNOs and network users presented and discussed their perspective and expectations on informational issues. Key feedback from the workshop is:

- Customers value timely and reliable information on low-cost connection opportunities, as well as consistency of data format across distribution services areas (DSAs),
- Different categories of DG customers have different informational needs and expectations, ranging from mere provision of region-wide network data, to project-specific information, to information services[7].
- The current Long Term Development Statement (LTDS) is aimed at technically literate users, who usually tend to connect at EHV[8] voltage level.

1.33. In their high level Forecast Business Plan Questionnaire (FBPQ) submissions for DPCR5, the DNOs forecast that over 75 per cent of DG capacity (around 5.7GW) will connect at 132kV and EHV levels via less than 500 connections. In contrast, they estimate that over 160,000 G83[9] LV connections will be made with a total generating capacity of some 184 MW (representing 2.5 per cent of DG connections)[10]. Between these two voltage levels it is estimated that some 19,000 high voltage (HV) generator connections will be made. This is illustrated in figure 1.

[7] Information-based services, especially for smaller customers, include user-friendly web-based costing tools as well as a full connection design service.
[8] Extra high voltage - usually between 22kV and 72kV.
[9] The standard categorisation of small generation - Engineering Recommendation G83 states that generators smaller than 16 amps per phase can be connected without obtaining prior permission from the DNO.
[10] We have included low voltage (LV) connections for photovoltaic and micro CHP (domestic) within the G83 category. The LV category includes all other types of DG connections at LV level (up to 1kV).

Figure 1: FBPQ forecasts for DG connections, by voltage level



1.34. Currently, the LTDS that the DNOs are required to produce only provides detailed network data at 33kV and above (EHV and 132kV). We are not at present persuaded that it would be efficient to require the LTDS to include 11kV network data but recognise that the DNOs should be able to respond effectively to a material increase in HV connection applications, as detailed in the following proposals.

1.35. Specific actions we are proposing to include:

- Improve accessibility of LTDS - full version to be made available, for free, online, with location clearly flagged from front screen,
- Standardise LTDS format and data form, linking it with annual cost reporting,
- LTDS to remain a technical document, but to include a section headed 'Information on connection process and costs', with links to relevant documents or tools such as the connection charging methodology and the Energy Network Association's (ENA's) DG Connection Guide[11]. We expect this to be readily implemented by April 2010,
- DNOs to commit to produce and maintain updated guidance document such as ENA's DG Connection Guide, suitable for all DG customer types (dedicated chapters by voltage level, technology, etc),
- DNOs to provide access to web-based indicative connection costing information[12]. We expect DNOs to provide this web-costing service for free, and be able to recover costs efficiently incurred in doing so,

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[11] Technical guide to the connection of generators to the distribution network - available from the ENA.
[12] By way of example, we expect such tools as a minimum to enable indicative costing of a DG connection project, as well as to explore the scope for avoiding reinforcement costs by suggesting alternative locations, reduction in agreed supply capacity, operational arrangements, etc.

- DNO to provide maps of 11kV circuits and heat-maps showing available capacity and best location for DG connections,

- DNOs to publish lists/maps of the best (therefore lowest cost) connection locations by voltage level,

- DNOs to complement their connection charging methodology statement with specific examples of DG connections (common across DSAs), from urban microgeneration to 50MW CHP, from windfarm to landfill, detailing assets involved in a representative minimum cost connection scheme for each type of DG and providing indicative unit cost for each (£/m cable, £/kit transformer, etc),

- DNOs to make available leaflets and/or web pages explaining - in plain English - how and where DG is likely to provide network benefits as opposed to adding network constraints.

1.36. We believe the proposed package of measures will enable all customer types to get easy access to information tailored to their needs and technical competence:

- EHV customers are more likely to seek detailed and updated data and information about the distribution network, so as to be able to evaluate connection opportunities and estimate associated costs for themselves, prior to making a connection application,

- HV customers are less likely to wish to carry out their own connection studies. They are more likely to benefit from tools that indicate where connection opportunities lie and provide indicative connection costs for different connection options. Some may simply want to deal directly with the DNO, avoiding the need for network data,

- LV customers are more likely to look for information for a specific location, and would benefit from indicative examples of DG connection arrangements that enhance their understanding of the potential costs involved.

1.37. It should be noted that DG connecting under the G83 requirements can connect without prior DNO consent[13] and therefore does not need to contract directly with the host distributor. For this reason G83 customers are not specifically targeted by these proposals.

[13] There is only a requirement on DG to inform the DNO that they have connected.

Use of system charging issues relating to DG

Treatment of demand and generation revenues

1.38. In 2005 'shallowish'[14] connection and use of system (UoS) charging was introduced for DG as a ring-fenced charging mechanism because the existing UoS charges were not cost reflective. The generation and demand revenue streams are treated separately within the current price control.

1.39. If cost reflective charging for DG is implemented there would be no reason to maintain the separation of generation and distribution revenues. Moreover, maintaining the current revenue separation under a cost reflective charging methodology could arbitrarily dilute the cost reflective price. By combining the revenues negative payments to DG in lieu of reinforcement would be correctly borne by customers rather than the other generators. This approach was advocated by four DNOs in response to the initial consultation document.

Distributed generation connection charging boundary

1.40. Although not raised by Ofgem in the initial consultation document, some respondents raised the issue of changing the DG connection charging boundary to a shallow or super shallow basis. This would involve the connectee paying less in connection charges, and the DNO including more of the costs associated with the connection within the generator distribution use of system (GDUoS) charges. A shallower connection charging boundary would mean that the range of assets that the DNO funds would be greater and arguably enable the DNO to maximise efficiency in their provision and any interaction with other network investment decisions, such as general reinforcement or asset replacement.

1.41. In DPCR4 a common, shallowish, connection charging boundary was agreed for both demand and generation. This meant that the connectee still paid a connection charge reflective of their location and complexity of connection – which was important since the existing charging arrangements are not currently cost reflective or locational.

1.42. The introduction of UoS charges that provide locational and cost reflective signals would mean the shallowish connection charge boundary may no longer be required. Furthermore, if the shallowish connection boundary were retained under a new methodology, care would be needed to ensure that costs are not double counted or charged. However, we see a value in a common connection boundary for generation and demand, and changing the demand connection charging boundary could have significant cost and management impacts. These issues will need to be

[14] A 'shallowish' connection is where the connectee pays for the new assets required to connect them to the existing network along with a proportion of network reinforcement if any is required.

considered as Ofgem and industry consider how to take forward the structure of charges project.

Generation connected pre-2005

1.43. This section provides further details about DG that connected or received a connection offer before 1 April 2005 ('pre-2005 connected DG') and the rationale for introducing GDUoS charges for all DG. More details can also be found in the initial impact assessment in appendix 14.

1.44. Around 12.9GW of DG capacity[15] that connected before 1 April 2005 is exempted from GDUoS charges until the end of DPCR4. These generators connected under a 'deep' connection policy - i.e. they paid for any sole and shared use assets required to connect them[16], including capitalised operations and maintenance (O&M) costs - and were not liable for ongoing GDUoS charges. As explained above, at DPCR4 the connection boundary was made shallowish and newly connected DG was made liable for GDUoS charges.

1.45. We consider that the UoS charges levied on a user should reflect the costs that the user imposes on the network. Under the present arrangements, almost 13GW of pre-2005 connected DG is not exposed to cost-reflective economic signals associated with its operational decisions on use of the system. Efficient use of the network in the long-run will result in a benefit to all customers (including DG) in the form of lower overall network costs.

1.46. We also believe that competition in generation is promoted when all players are facing consistent charging arrangements, whereas the current framework creates a substantial disparity between pre- and post- April 2005 connected DG.

Other DG related issues

Standard connection agreement

1.47. We see that there is currently a Distribution Connection and Use of System Agreement (DCUSA) Change Proposal (DCP033) being developed by the industry to extend the current standard terms of connection, which are already a schedule to DCUSA. The change proposal seeks to build upon the current simple terms by introducing more substantial standard connection terms for both suppliers and larger customers (typically half-hourly, including distributed generators, and unmetered services). Inter alia, the change proposal could improve the transparency and

[15] Data as of 31 March 2005. Source: ENA website.
http://www.energynetworks.org/spring/engineering/pdfs/DGSG/Connection_Activity_DNOs_Dec2005_rev3.pdf
[16] Subject to caveats for the costs of reinforcements, such as the limit on contributions towards assets up to one voltage level above the voltage of connections.

uniformity of the connections process and reduce the administrative overhead for DG developers. Bearing in mind the potential benefits, we intend to closely monitor the progress of this change proposal.

Proportionate administrative requirements

1.48. The Distribution Code Review Panel has set up a working group to review the Engineering Recommendations relating to the connection of generation to distribution networks; Engineering Recommendations G59[17] and G75[18]. We have not formally reviewed this proposal, but we understand that it is intended that a single Engineering Recommendation will replace both of the existing recommendations. We believe it is important that this new recommendation, which will apply to all but the very smallest generators, recognises the size of generator so that the technical connection requirements are proportionate to the impact that the generator will have on the network.

Industry code developments

1.49. During the development of British Electricity Trading and Transmission Arrangements ('BETTA'), which were implemented in April 2005, parties raised a number of issues with the treatment of DG within the transmission charging arrangements. These issues included cost-reflectivity, incentives created by embedded benefits and the interaction with transmission access issues. Ofgem acknowledged that there was a need to review the transmission charging arrangements with respect to DG after BETTA, but also the related issues of transmission access, operation and planning. Since then, Ofgem has published further thoughts on this topic resulting, at the request of industry, in the establishment of the transmission arrangements for distributed generation (TADG) working group. The primary role of TADG was to develop models for enduring access, planning and transmission charging arrangements that reflect the impact of DG on the transmission system. In considering changes it focused on the applicability of agency models which enable DG to use an agent, such as their supplier or DNO, to deal with transmission-related issues.

1.50. We continue to believe that agency models, whether DNO or supplier based, may provide an appropriate means for smaller DG to deal with transmission issues, as they could help reduce burden on DG and take into account diversity of generation. We also think that in the short term the development of such models should make use of existing interfaces and align with the current placement of responsibilities. However, it is also important to take into account the evolution of those responsibilities in the long term, e.g. the development of more active management of the distribution networks with more dynamic and wider interfaces between the DNO and DG. These issues are currently being progressed by National Grid Electricity Transmission (NGET) in conjunction with industry. We note that,

[17] G59 covers DG connecting at or below 20kV and where the plant does not exceed 5MW.
[18] G75 covers DG with output greater than 5MW or at system voltages greater than 20kV.

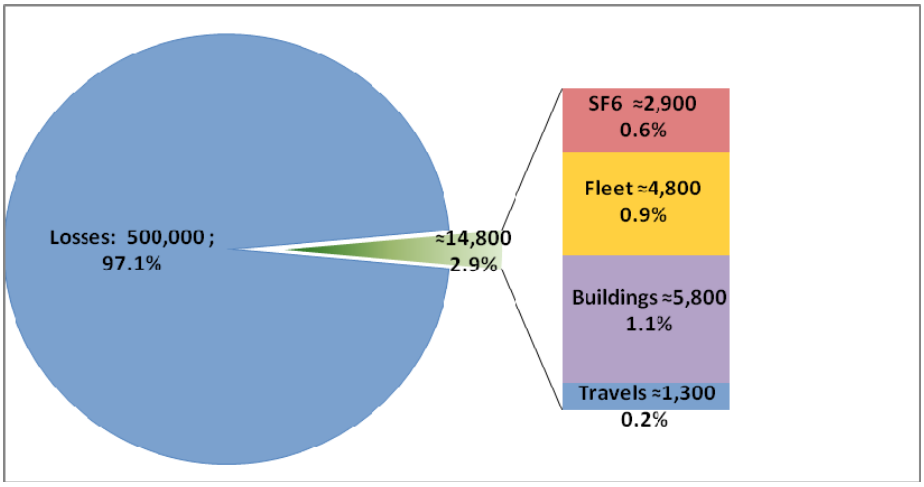
following on from the work of TADG, National Grid is undertaking a review of embedded benefits and an amendment to the Connection Use of System Code (CUSC) CAP167, has been raised which seeks to build upon the DNO agent role introduced by CAP097 in dealing with the circumstances in which a DG connection leads to transmission works. We will consider CAP167 and any other proposals in due course, on their merits and based on the information available to us at the time.

1.51. In terms of an enduring transmission charging solution for generators connected to the distribution network, we remain of the view that there are important issues with the current treatment of DG in the transmission arrangements that need to be addressed. Primarily, it is important that transmission charging reflects the costs imposed on the transmission network and gives appropriate credit for benefits provided. This promotes the economic development of the transmission network and helps to ensure that competition in generation and supply takes place on a level playing field. It is also important that transmission access is allocated in an efficient and coordinated manner. In addition it is important that the administrative and regulatory burden for smaller participants in the market is proportionate.

Losses

1.52. Figure 2 shows that the vast majority of DNO greenhouse gas (GHG) emissions are related to electricity losses (around 97 per cent of total DNO GHG emissions).

Figure 2: Average DNO GHG emissions by activity (tCO_2e, %)[19]



1.53. Losses comprise a mixture of technical losses and unaccounted for consumption. Technical losses are the electrical system losses (i.e. heat loss from current carrying network equipment) and the auxiliary supplies of electricity to

[19] Updated from initial consultation document to reflect more recent reported data.

network equipment and its related infrastructure. The unaccounted for losses are normally referred to as commercial losses and arise from a number of areas including theft, un-billed accounts, estimated customer accounts and errors due to the approximation of consumption by un-metered supplies. Some aspects of commercial losses adjust over time during the settlement process making real time comparison between electricity entering and leaving the system difficult.

Current incentive

1.54. Following the initial consultation, some DNOs argued that the current loss incentive is inadequate in that it does not provide them with a positive return for investing in low loss equipment. We therefore tested this assertion by creating a simple spreadsheet to compare the revenue stream of investing in a typical low loss transformer versus that of a standard one (using DNO manufacturer data).

1.55. We found that if the DNOs were in a commercial setting where they experienced losses as a cost of lost energy, depending on the transformer specification, it would be cost effective for them to invest in a more expensive low loss transformer, since the loss savings generated would payback the extra investment within the life of the transformer.

1.56. We then tested our example against the DPCR4 regulatory framework, and found that DNOs should receive an adequate incentive to invest in a higher cost, lower loss transformer.

Unmetered supplies

1.57. There are certain small supplies, such as street lights, illuminated bus shelters etc. where the cost of metering would be prohibitive. Therefore the owner is charged based on an estimated usage for their inventory of equipment. However this means that errors can occur through incorrect inventory and incorrect usage estimation resulting in the electricity billed not equalling the electricity used.

1.58. However, we note that unmetered supplies represent approximately one percent of the electricity being distributed, which means than any error in unmetered supplies will be a very small fraction of a DNO's losses. We also note that the introduction of an annual reconciliation of inventories to that held in settlement has improved the situation.

Substations energy usage

1.59. At present there is an inconsistency in the treatment by DNOs in their methods for dealing with the electricity consumed within their substations for heating, lighting and ancillary supplies. Electricity used at substations is unmetered in the majority of cases. Some DNOs pay a supplier for this unmetered consumption.

1.60. During environment working group (EWG) discussions, DNO representatives agreed a consistent approach should be adopted across the industry. We are exploring options around how this could be implemented.

Business carbon footprint (BCF) reporting methodology

1.61. We are proposing to introduce reporting requirements for the DNOs' BCF. We have presented this proposal at the EWG and we intend to continue engaging with the industry on this issue. We consider that it is important for DNOs to be aware of their overall environmental impact and to focus their attention on opportunities for reducing their carbon footprint, where proportionate.

1.62. We are mindful of the main concerns DNOs have raised with us, in terms of the proportionality of administrative costs associated with data collection. For this reason we propose to base the methodology for BCF reporting on the Greenhouse Gas Protocol, an internationally recognised tool which provides guidance on how to set up a corporate reporting methodology and framework[20].

1.63. In the following sub-paragraphs we set out some details of our proposed methodology.

Organisational boundaries

1.64. We propose to adopt an 'operational control' approach: DNOs shall report 100 per cent of GHG emissions from operations on which they have operational control, i.e. the full authority to introduce and implement its operating policies.

1.65. We consider that this approach enables the capture of emissions from activities outsourced to independent contractors (this might require a new round of contractual negotiations to incorporate environmental reporting in contracts) and avoids need for recalculating emissions baselines every time a currently outsourced operation is then in-sourced (or vice versa).

1.66. It is difficult to assess at present the administrative effort and relevance of different outsourcing and subcontractor relationships.

Operational boundaries

1.67. We propose to restrict reporting to direct GHG emissions ('Scope 1'- emissions from sources owned or controlled by the company, e.g. during processes and operations) and electricity indirect GHG emissions ('Scope 2'- emissions related to

[20] GHG Protocol Corporate Standard, available here: http://www.ghgprotocol.org/files/ghg-protocol-revised.pdf

generation of purchased electricity). Scope 2 of the protocol would require DNOs to report the emissions from electricity both for business usage and lost on the networks: we expect losses to be reported separately from end-use emissions[21].

1.68. We propose that other indirect emissions ('Scope 3', i.e. consequences of the company's activities but from sources not owned nor controlled by the company) shall be excluded, on the grounds of proportionality.

Conversion factors

1.69. We consider that direct measurement of emissions is likely to be prohibitively expensive and disproportionate to benefits. Therefore emissions will be estimated from input data such as miles travelled, electricity consumed etc. The input data is then converted using Defra's conversion factors and guidelines[22]. These conversion factors are updated in June each year. All emissions would then be expressed as tonnes of CO_2 equivalent (tCO_2e).

1.70. The factors are broken down in several sub-categories in order to adhere to many different situations (e.g. for vehicles: commercial/passenger nature, different fuel technology, engine size).

Data submission

1.71. We propose that the annual reporting shall refer to the financial year, starting from 2010-11. We propose that DNOs submit data for 2009-10 and – if available – for 2008-09, for information only, to assist in the development of the reporting framework. Submissions from 2010-11 onwards will be published annually.

Emissions reported

1.72. We propose to report emissions (tCO_2e) against the following headings:

- Losses, based on the losses reported to Ofgem,
- Operational vehicles, based on fuel purchase or vehicle mileage,
- Business travels (with separate indication for different transport means), based on distance (between airports, stations, addresses/cities),
- Building usage, based on energy (gas & electricity) bills,

[21] See appendix A of the above cited document.
[22] Guidelines to Defra's Greenhouse Gas Conversion Factors for Company Reporting, available here: http://www.defra.gov.uk/environment/business/envrp/pdf/ghg-cf-guidelines2008.pdf
Annexes available here: http://www.defra.gov.uk/environment/business/envrp/pdf/ghg-cf-guidelines-annexes2008.pdf

- Sulphur hexafluoride (SF6), based on quantity reported according to ER S38[23], and
- Diesel mobile generation, based on fuel used.

1.73. These categories cover the sources of BCF emissions we have identified, based on information shared by DNOs. This is consistent with the GHG protocol, which is informed by the principle of completeness, i.e. it considers that there are no de minimis thresholds for emissions. If it is decided that additional categories are required, they could be grouped under 'other emissions' (for example some DNOs have suggested hydrofluorocarbons (HFC) emissions from air conditioning).

BCF league table

1.74. While the reporting framework provides the pre-condition for BCF management, the league table aims to focus DNO efforts by creating a reputational driver for improving DNO environmental performance.

1.75. The league table would report DNOs' performance in reducing their BCF against a baseline of their past BCF over time, creating a relative ranking that would recognise the efforts put forward by each DNO. The baseline would be specific for each DNO, and would set the benchmark for assessing DNO performance each year.

1.76. The baseline for the initial phase would necessarily be based on the first year of available reporting, 't0'. Subsequently, for each reporting year 't' the updated baseline can be based on the weighted average between the original baseline at 't0' and the performance in year 't-1'; in this way, a DNO would still see the benefits of environmentally friendly actions in years to come[24]. We are considering whether it is appropriate to start the publication of the league table after the start of DPCR5. A first year of reporting without a published league table would be allowed, to test robustness.

1.77. The ranking of the league table would use the data reported under the methodology developed in the previous subsection. Losses would be excluded since they are already incentivised separately. Building usage would be included even though it is captured within Defra's Carbon Reduction Commitment (CRC) since not all the DNOs qualify for inclusion within the CRC scheme.

1.78. It is important to recognise in the league table the efforts of DNOs that have implemented actions on management of GHG emissions (if proven to be material) before the start of DPCR5. This can be taken into account in several ways:

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[23] The Engineering Networks Association (ENA) Engineering Recommendations ER S38
[24] The alternative would be to use the performance in the previous year to set the baseline for the next period: in this way, however, an outstanding performance in reducing emissions in any year would make it much more difficult to make substantial further savings in subsequent years.

- Experience from pioneering DNOs has shown that emissions can increase in the first few years due to adjustments/improvements in reporting, and then decrease when action against reporting findings is undertaken. DNOs that have already undertaken voluntary reporting would hence benefit from being proactive,

- For specific items of emissions, indicators of early action can be agreed and a proportionate uplifting of the baseline can be allowed. For example, number of hybrid vehicle, energy efficiency certification, videoconferencing facilities.

Undergrounding in Areas of Outstanding Natural Beauty ('AONBs') and National Parks

1.79. Our views on refinements to the current undergrounding scheme proposed by stakeholders are set out in this section.

Extending the scheme to other areas

1.80. The initial consultation document sought views as to whether the scope of the scheme should be extended to other protected or conservation areas. Some respondents suggested there may benefits to other areas of high quality, but not designated, landscape. There were also suggestions that the scheme could be extended to address the issue of noise pollution. Although we recognise that there may be valuable environmental benefits relating to such issues, there is only a moderate allowance available under this scheme. Any extension of the scheme to other areas would reduce the money available for AONBs and National Parks and increase the number of stakeholders that DNOs are required to consult with. Given that the scheme was designed specifically to address the Authority's obligations with respect to National Parks and AONBs we consider that it is most appropriate to maintain the current scope.

1.81. We note suggestions from some stakeholders that the scheme should be mandated to encourage the participation of all DNOs. We do not intend to mandate the scheme on the basis that DNO buy-in is an important contributor to the success of the scheme and stakeholders have an opportunity to influence DNOs' priorities via the stakeholder engagement process.

1.82. The funding of the scheme has attracted most comments from stakeholders, particularly in terms of the limitations of the DPCR4 caps. We have reviewed actual DPCR4 expenditure and details of rejected schemes provided by DNOs and found that a 20 per cent increase on the current caps would deliver a significant proportion of schemes that have been rejected on the basis of cost. Respondents should note that the allowances are not set to provide full funding for a DNO's programme of undergrounding. Given the benefits that DNOs can derive from the scheme, we welcome DNOs providing matching funding and working with stakeholders to seek out alternative sources of funding such as heritage, lottery and EU development funds. Based on our analysis of rejected schemes views are invited on the feasibility of the following revised caps:

- LV - £78 per km,
- HV - £102 per km,
- EHV - £420 per km

1.83. An alternative option to revising the caps would be to remove the voltage caps altogether but maintain the overall cap. This would allow DNOs to underground large iconic schemes subject to a justified and agreed position with stakeholders. However, respondents should note that the cost caps have been put in place to ensure value for money on schemes and reflect that customers' willingness to pay is based on particular volumes of overhead lines. Views are invited on the preferred approach.

1.84. In order to finalise the allowances discussed in chapter 2 we require DNOs to update us on the number of overhead lines in AONBs and National Parks. Questions have been included in the February FBPQ.

1.85. As a minimum, DNOs must be able to demonstrate that they have taken account of advice from local environmental groups and/or planning bodies in deciding how best to prioritise any expenditure on network undergrounding. We note that DNOs' approaches to consulting and communicating with relevant stakeholders have varied during DPCR4. We intend to review how DNOs have met this requirement early in DPCR5 and highlight examples of best practice.

Preventing new overhead lines

1.86. Some stakeholders suggest that the scheme should be used to prevent new overhead lines being built in designated areas (i.e. use the allowance to top up the difference in costs between new construction and undergrounding). We are not minded to extend the scheme to fund new underground connections in designated areas. The premise that funding is based on the removal of kilometres of overhead lines has been an important feature of the scheme functioning effectively and a feature that we would like to retain. We are also aware that planning and environmental legislation could be prohibitive of new overhead lines in AONBs and National Parks and provide stakeholders with an opportunity to object to the construction of new overhead lines. Notwithstanding this, there is nothing within the remit of this scheme to prevent overhead lines being replaced with more innovative supply solutions such as a renewable system if there is a customer commitment and costs are efficient.

Boundary issues

1.87. Some stakeholders suggest that lines overlapping the visual boundary of the AONB or National Park should be allowed within the scope of the scheme. Our view is that lines removed beyond the AONB/National Park boundary should not be funded by the scheme. The scheme works well mechanistically and we do not consider that incorporating the subjectivity of a visual boundary would add value. We are comfortable that the existing parameters of the scheme provide sufficient choice to stakeholders and DNOs of lines to underground.

Interactions with normal replacement work

1.88. Some stakeholders suggest that the rule that expenditure must be demonstrably in addition to the DNOs' existing programme of work should be removed. Our view is that visual amenity should drive undergrounding expenditure under this scheme rather than quality of supply considerations. Giving stakeholders some discretion over which lines are undergrounded is a good way of demonstrating having met this requirement. Nevertheless, we accept that where overhead lines in AONBs/National Parks form part of the DNO’s normal asset replacement programme, there may be a preference to replace the existing assets with underground cables. In such cases the undergrounding allowance can be used to fund the cost difference between normal replacement work and the new underground solution. However, we stress the need for the replacement of these lines to be driven principally by visual amenity benefits.

DPCR4/5 overlap

1.89. Stakeholders have raised questions as to how projects initiated in DPCR4 but are unlikely to complete until DPCR5 will be treated by the scheme. DNOs are entitled to log up costs for schemes under the DPCR4 funding mechanism where overhead lines are removed on or before 31st March 2010. Where lines are removed after this date, funding will be provided by DPCR5 allowances.

Project officer funding

1.90. Some DNOs have asked that the allowance be used for the funding of a project officer to work on the scheme. Given variations in the volumes of kilometres implied by the allowances and the potential for DNOs not to use the full allowance, we are not persuaded that it would be efficient in all cases to second a project officer. However, if DNOs consider it to be an efficient approach that yields benefits in terms of stakeholder relations, it should be funded by the DNO through its general allowances.

Proposed allowances

1.91. We propose a total of £60.6 million for undergrounding in AONBs and National Parks during DPCR5. The proposed allowances per licensee are set out in table 1. These are based on an average of £/customer and £/kilometre calculations derived from the DPCR5 customer research.

Table 1 - Proposed allowances per DNO for undergrounding in AONBs and National Parks during DPCR5

DNO	Max capex over 2010-15 for undergrounding £m
CN West	£ 5.8
CN East	£ 3.9
ENW	£ 5.0
CE NEDL	£ 4.4
CE YEDL	£ 3.1
WPD S West	£ 8.2
WPD S Wales	£ 3.6
EDFE SPN	£ 6.2
EDFE EPN	£ 5.3
SP Distribution	£ 2.7
SP Manweb	£ 4.3
SSE Hydro	£ 3.0
SSE Southern	£ 5.3
Total	£ 60.6

Appendix 7 - Customers

1.1. The customer chapter (chapter 3) in the main document sets out the key customer issues and areas we want DNOs to focus on during the next price control period including the number and duration of interruptions, broader customer service, worst served customers and connections. This appendix provides more technical detail on our plans for improving the customer service incentive arrangements. It is aimed primarily at DNOs and the industry but it may also be of interest to consumer groups and other bodies.

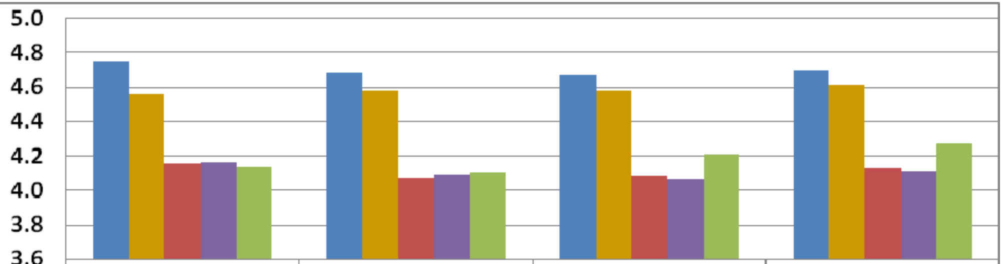
Telephony

1.2. The telephony incentive is based on the results of ongoing customer surveys on DNOs' call handling performance. We propose running the telephony scheme in parallel with the new broad customer satisfaction measure for the early part of DPCR5 with a view to replacing the telephony incentive with a broader customer satisfaction incentive mechanism as soon as is practicable within the price control period. We are seeking to make a number of improvements to the telephony scheme for the years that it will run during DPCR5.

Streamlining the customer survey attributes

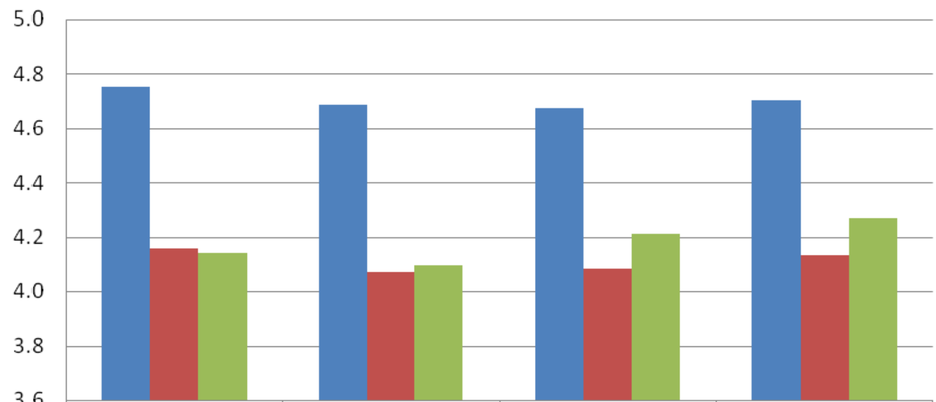
1.3. Given strong correlations between the politeness and helpfulness customer survey attributes and the accuracy and usefulness attributes, we intend to streamline the DPCR5 scheme to three attributes: politeness of staff, accuracy of information and satisfaction with the speed of response. This position was supported by respondents. The impact of this streamlining on DPCR4 average scores is shown in figure 2. Comparing these scores to the current average scores based on all five attributes (shown in figure 1) demonstrates that streamlining from five attributes to three attributes does not have a significant effect on the scores overall.

Figure 1 - Overall mean scores for 5 assessed attributes



	2005/06	2006/07	2007/08	April to October 2008
Politeness	4.8	4.7	4.7	4.7
Willingness	4.6	4.6	4.6	4.6
Accuracy	4.2	4.1	4.1	4.1
Usefulness	4.2	4.1	4.1	4.1
Assessed speed	4.1	4.1	4.2	4.3

Figure 2 - Affect on overall assessed scores of streamlining the attributes



	2005/06	2006/07	2007/08	April to Oct 2008
Politeness	4.8	4.7	4.7	4.7
Accuracy	4.2	4.1	4.1	4.1
Assessed speed	4.1	4.1	4.2	4.3

Inclusion of unsuccessful calls

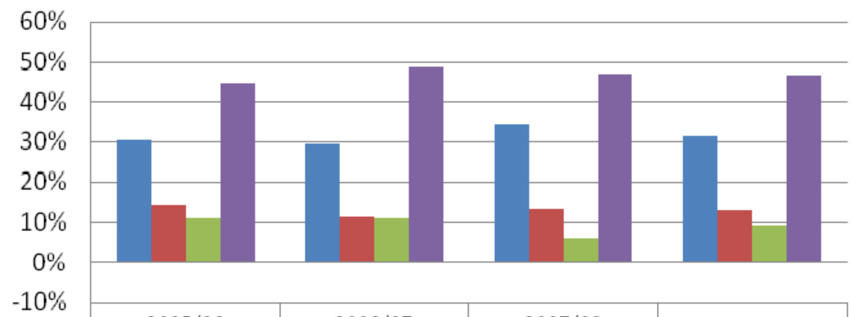
1.4. A number of respondents support the inclusion of unsuccessful calls into the incentive scheme to supplement the telephony survey results. We are concerned that there is potential for two DNOs to achieve the same scores under the survey even though they may have successfully dealt with significantly different percentages of calls over the same period. WPD consistently has the lowest percentage of unsuccessful calls (1 per cent) whilst EDF LPN has the highest percentage of unsuccessful calls in each of the three years (25 per cent, 23 per cent & 17 per cent).

1.5. Table 1 sets out details of unsuccessful calls relating to each DNO over the last three years. To address this we propose scaling the survey scores by the population of successful calls, using the formula: Score = ((politeness + accuracy + speed)/3)* (1 – % unsuccessful calls * 0.75)

1.6. We recognise there may be reasons beyond the DNO's control for calls being unsuccessful. On average the number of calls terminated by DNOs make up 13 per cent of unsuccessful calls while calls not allowed into the queue or flushed make up a further 9 per cent. These figures represent 22 per cent of total unsuccessful calls in each year. Nevertheless, we are keen to ensure that DNOs are incentivised to keep all unsuccessful calls to a minimum, not just those that may appear to be directly within their control. As such we propose a 75 per cent weighting on all unsuccessful calls as we believe that DNOs should be encouraged to work with their local telephony providers to deliver an appropriate level of service.

1.7. Figure 3 shows the breakdown of unsuccessful calls across all DNOs. We invite views on placing a 75 per cent weighting on all unsuccessful calls in the revised telephony metric for DPCR5.

Figure 3 - Proportions of unsuccessful calls broken down by key measures

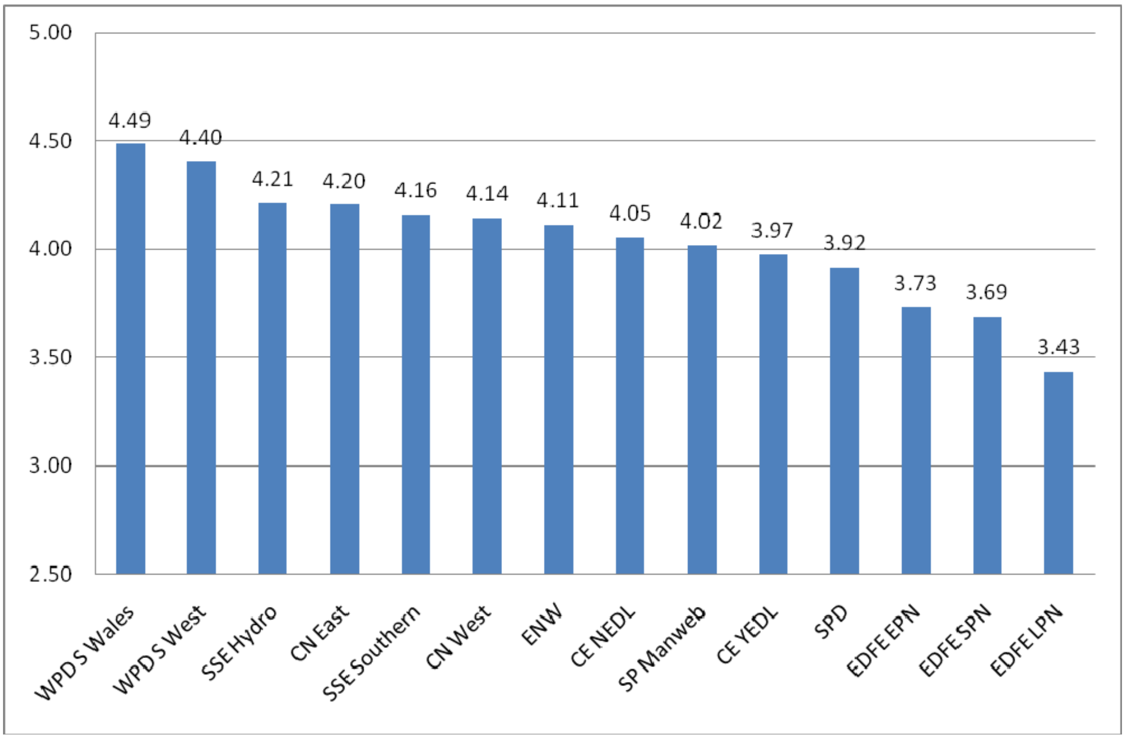


	2005/06	2006/07	2007/08	average
KM5a (total calls not reaching the specified lines)	30%	30%	34%	31%
KM5b (total calls terminated by the DNO)	14%	11%	13%	13%
KM5c (total calls not allowed into the queue or flushed)	11%	11%	6%	9%
KM5d (total calls abandoned by the customer in the queue)	45%	48%	47%	47%

Table 1 - Average assessed scores based on streamlining attributes from five to three and percentages of unsuccessful scores

	Assessed scores (3 attributes)			% unsuccessful calls		
	2005/06	2006/07	2007/08	2005/06	2006/07	2007/08
CN West	4.28	4.30	4.35	3%	7%	5%
CN East	4.36	4.34	4.39	3%	7%	5%
ENW	4.24	4.10	4.38	6%	5%	1%
CE NEDL	4.43	4.44	4.44	13%	7%	14%
CE YEDL	4.32	4.36	4.36	9%	9%	16%
WPD S Wales	4.49	4.49	4.55	1%	1%	1%
WPD S West	4.44	4.40	4.48	1%	1%	1%
EDFE LPN	4.15	4.12	4.02	25%	23%	17%
EDFE SPN	4.28	4.16	4.02	15%	16%	14%
EDFE EPN	4.30	4.24	4.16	17%	18%	12%
SPD	4.11	4.00	4.15	6%	5%	5%
SP Manweb	4.21	4.15	4.28	6%	8%	5%
SSE Hydro	4.58	4.52	4.57	13%	13%	4%
SSE Southern	4.37	4.34	4.40	6%	7%	6%
DNO Average	4.32	4.28	4.32	9%	9%	9%

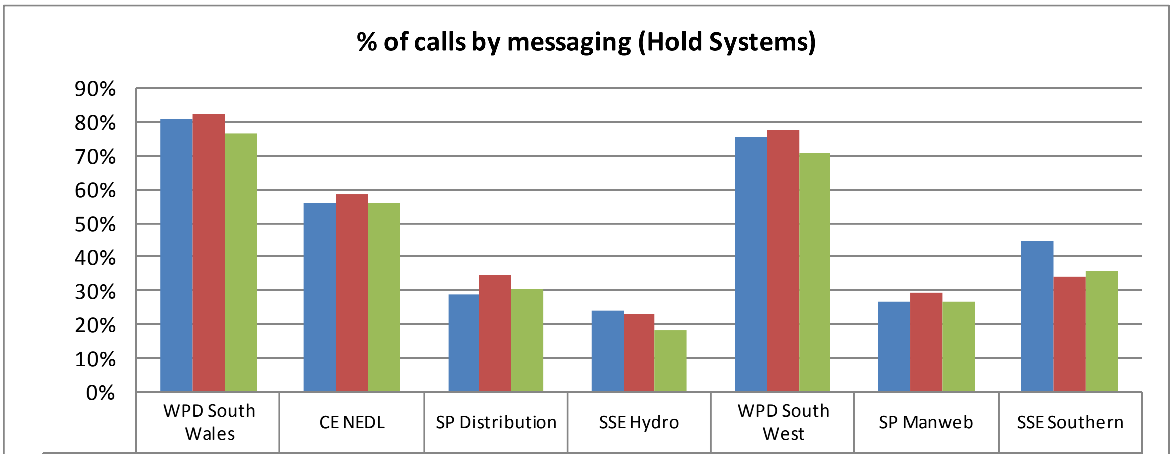
Figure 4 - DNO average scores (2005-08) based on proposed three attributes with a 75% weighting applied to unsuccessful calls



Other issues

1.8. Respondents to the initial consultation document broadly supported Ofgem's proposal to incorporate an incentive on calls dealt with by messaging into the existing scheme. For DPCR5 we propose incorporating customers that have been dealt with by messaging into the survey. Currently, the percentage of calls handled by messaging varies across the DNOs, from 9 per cent to 82 per cent. The graphs below show percentage of calls handled by messaging for DNOs on hold systems[25] only. For DNOs using the hold systems WPD has the highest number of calls by messaging in each year compared to SSE Hydro. For DNOs using the redial systems[26] the figures vary slightly. In 2005-06 CN East had the highest percentage, whilst in 2006-07 and 2007-08 CN West had the highest percentage.

Figure 5 - Percentage of calls handled by messaging on hold systems



	WPD South Wales	CE NEDL	SP Distribution	SSE Hydro	WPD South West	SP Manweb	SSE Southern
2005/06	80%	55%	29%	24%	75%	26%	44%
2006/07	82%	58%	34%	23%	77%	29%	34%
2007/08	76%	56%	30%	18%	70%	27%	35%

1.9. Respondents also support the proposal for DNOs to run their own survey by contracting with one provider using a format specified by Ofgem similar to the gas surveys. We welcome this approach which is expected to help eliminate the issues around data protection and allow a broader cross-section of customers to be surveyed.

[25] DNO telephony system that requires customers to wait for an agent following an automated message.
[26] DNO telephony system where customers are required to dial an alternative number to speak to an agent following an automated message.

Connections

1.10. For the regulatory treatment of connections for DPCR5 we advocate changes to the regulatory framework to further encourage competition where it is feasible and we propose a number of measures to enhance protection for customers with regard to price and service. This section sets out the technical detail of our proposals for allowing margins in competitive segments of the market to facilitate further competition. It also explores the scope and options for further regulation in market segments where competition has not developed and where customers choose the non-competitive route.

Segmenting the market

1.11. Our proposals involve determining which parts of the market are, and are not, potentially competitive. The connections industry can be categorised in several ways; by voltage level/type of connection and by activities that are/are not open to competition[27]. It is important to consider the market segments that are most attractive to competitive providers. We appreciate that competition may not be feasible for all segments of the connections market and that most appetite for competition exists in the LV market (excluding small scale domestic connections) and at HV. These are most likely to be the highest value market segments which understandably make them most attractive to competitive providers. Our initial view is that LV small scale domestic connections (say developments of less than 4 properties) are not currently attractive to new entrants given that uptake of competition in this segment is limited and therefore DNOs should not be permitted to earn margins on activity in this segment. Table 2 sets out our views on the competitive potential of the relevant market segments. Table 3 sets out our initial views on where margins should be allowed.

1.12. There are legislative limits to the scope of activities which are open to parties other than the host DNO. For example, providing a point of connection to the DNO's network can only be carried out by the host DNO and is therefore referred to as a non-contestable activity. The contestable/non-contestable boundary is an important consideration in determining where margins should be permitted[28]. Margins would only be applied to the contestable element of the charge in market segments that are proven to be competitive, regardless of whether the customer opted for the competitive route or not in obtaining a quotation. This should be relatively simple to administer given that DNOs already break quotations down to show the contestable and non-contestable elements of a charge. It will also avoid customers being charged differently depending on whether they request a competitive quotation or request for

[27] Another more complex distinction to make is the route that the customer may choose to obtain a connection (i.e. via competition in connections or by using the DNO as a provider of last resort). In our view it would not be sensible to allow margins where the market is segmented on this basis because of the level of complexity involved and potential to create perverse charging arrangements.
[28] The activities that are currently considered to be non-contestable are described in ' Gas and Electricity Connections Industry Review 2007-08: Appendices' (143/08) 16 Oct 2008.

the DNO to undertake the full scope of works. We do not consider that it is appropriate to allow a margin on non-contestable activities as this would have no positive impact on competition levels and would result in increased charges for customers.

1.13. Views are invited on:

- our approach to segmenting the market as set out in tables 2 and 3,
- the feasibility of competition in each market segment we have identified, and
- the level at which regulated margins should be set on contestable charges.

Table 2 - Initial views on competitive potential of market segments

Market segment	**Market value**[29]	**Competitive potential**
LV small scale domestic (1-4 premises)	£353 million[30]	Unlikely - low value, low margin work
Remaining LV market		High potential
HV	£53 million	High potential
EHV	£45 million	Low volumes, highly specialist, scope for growth
DG	£36 million	Low volumes, scope for growth
Unmetered connections	£45 million	Initial low uptake but growing

Table 3 - Initial views on the scope of allowed margins

Market segment	**Contestable charges**	**Non-contestable charges**
LV small scale domestic (1-4 premises)	Disallow margins	Disallow margins
Remaining LV market	Allow margins	Disallow margins
HV	Allow margins	Disallow margins
EHV	Allow margins	Disallow margins
DG	Allow margins	Disallow margins
Unmetered connections	Allow margins	Disallow margins

Competition tests

1.14. As set out in chapter 3 of the Policy Paper, we propose a number of competition tests that DNOs must meet in order to be able to earn an unregulated margin on connections activities in competitive market segments. The competition

[29] Based on charges levied by DNOs and IDNOs. Totals do not include the value of connections undertaken by independent connection providers.
[30] Total value of LV market.

tests would need to encompass more than just market share. It is possible that some DNOs are retaining market share due to competitive pricing and good service levels, in which case competition is constraining prices and we could allow the DNO to earn an unregulated margin. We propose a number of tests as set out in table 4 to enable us to take a broad view of competition. Further work needs to be done to determine appropriate metrics against each test. We would value respondents' views as to how the metrics should be set, what proportion of the tests should be met and which are the most important tests. For this approach to work there would need to be an incentive on DNOs to continue to maintain effective competition once the tests are met. If there is evidence of competition levels declining once the regulation of margins has been lifted, we will review the need to revert back to regulated margins or consider extending the review period if there are signs of competition developing.

Table 4 - Proposed basis of competition tests

Market share	▪ Number/value of competitive connections ▪ HHI scores[31]
Market penetration	▪ Number of active ICPs/IDNOs (affiliates and non-affiliates)
Price	▪ Average price metric
Investigation findings	▪ Breaches of non-discrimination conditions of licence (SLC19) ▪ Competition Act breaches
Customer awareness of competitive alternatives	▪ Customer survey ▪ Number of competitive quotations issued
Facilitation of competition	▪ Enabling of LV live jointing ▪ Quality of website information
Complaints	▪ ICP complaints to Ofgem/Ombudsman referrals ▪ Other evidence of non-compliance with spirit of competition
Compliance with SLC15 (Standards for the provision of Non-Contestable Connections Services)	▪ 90 per cent compliance specified ▪ Services specified include proving quotations, responding to requests for design approval and completion of works

[31] Herfindahl-Hirschmann index; see 'Market Investigation references: Competition Commission Guidelines' June 2003, http://www.competition-commission.org.uk/rep_pub/rules_and_guide/pdf/cc3.pdf

Proposed timescales

1.15. We propose to allow DNOs to earn regulated margins for three years before assessing whether these arrangements have been successful in encouraging effective competition. DNOs would then have a period of nine months to report the connections data to Ofgem and present a convincing case for effective competition as set out in figure 3.2 of chapter three. However, this does not preclude DNOs from making such a case before that date and applying to have the regulation of their margin lifted. Views are invited on the reasonableness of this approach and the proposed timescales.

Connections provided by the DNO on a non-competitive basis

1.16. A summary of existing protection for customers that do not choose the competitive route to obtain a connection is provided in table 7 below. Options for enhanced protection for connections customers are set out below.

Option 1 – Extend regulation to all connections

1.17. Consultation respondents highlighted the need for a more prescriptive set of connections standards with regard to the provision of quotations (accuracy and timeliness) and the completion of works. Respondents expressed concerns that the standards for non-competitive electricity connections fall short of those in gas and those for the provision of non-contestable services. We propose extending the existing electricity standards of performance[32] to provide protection for customers that experience delays with quotations and the completion of works. It seems logical that the timescales for issuing quotations and completing works for non-competitive connections should mirror those that were introduced to support competition in the market. These are enshrined in SLC15[33] of the electricity distribution licence and summarised in table 5 and table 6. To reinforce compliance with the standards we intend to introduce a licence condition similar to that in gas[34] enabling Ofgem to take enforcement action should DNOs' compliance fall below a minimum average level of performance.

Option 2 – Price regulated segments where competition is unlikely to ever be effective

1.18. DNO consultation responses did not support standard pricing mechanisms on the basis that there is sufficient price protection for customers from the Ombudsman and the Ofgem determinations route. There were also concerns that standard pricing may not be feasible on a national level given volatility in contractor and materials rates. Nevertheless, there was some recognition from some DNOs that there could

[32] The Electricity (Standards of Performance) Regulations 2005, SI No.1019.
[33] Standards for the provision of Non-Contestable Connections Services.
[34] Standard Special Licence Condition D.10 of the Gas Transporters licence.

be standard charging for certain classifications of connections such as urban single premise service connections.

1.19. Competition for urban single premise connections may never materialise due to the low margins associated with this work. Price capping would ensure consistent treatment of these customers and minimise the potential for disputes. Depending on views as to the realistic potential for competition in other segments, there may be a role for price capping in other areas. We note that Local Authority respondents have indicated concerns with the transparency of recent large scale price increases for unmetered connections. We would welcome views on whether we should introduce an average revenue cap for such connections.

Option 3 – Price accuracy scheme

1.20. Gas connections customers currently benefit from a connection charging accuracy scheme[35] which enables customers to challenge the gas distribution networks' (GDNs) connections charges and provides refunds in appropriate circumstances. Given the recent disbanding of energywatch and the informal advice function that they have provided in the past on connection charges, a DNO accuracy scheme could enhance protection in this area. It would also bring some symmetry to redress arrangements for electricity and gas connections and could serve to enhance protection for large business customers that do not have recourse under the new redress arrangements.[36] We invite feedback on the need for such a scheme for electricity connections.

Option 4 – A cost-efficiency incentive on connections

1.21. The capex efficiency incentives are set on a net basis and as such do little to encourage efficiency as the costs of sole use connections are fully recovered from customers. This raises questions about whether customers are getting value for money. One idea is to expose a proportion of total gross connection costs to the capex incentive allowing DNOs to keep a proportion of any cost-efficiency savings made. The main advantage of this approach is that it would provide a stronger efficiency incentive for DNOs which could in turn result in cost savings for customers. Nevertheless, we recognise that the uncertainty of DNO forecasting and price effects could make this a less appealing option. An alternative option would be to introduce a standard pricing mechanism.

[35] Gas Transporters Licence: Standard Special Condition D10 (3).
[36] Definition of 'relevant consumer' pursuant to the Consumers, Estate Agents and Redress Act 2007 is cited in SI No. 2268 ' The Gas and Electricity Regulated Providers (Redress Scheme) Order 2008'

Table 5 - SLC 15 - Provision of quotations

Service	Required Standard (to be achieved within 90 per cent of all cases)
1a) LV demand: For a new demand connection to the licensee's distribution system where the highest voltage of the assets at the point of connection and any associated works is not more than one kV.	Within 15 working days of receiving the request.
1b) LV generation: For a new generation connection to the licensee's distribution system where the highest voltage of the assets at the point of connection and any associated works is not more than one kV.	Within 30 working days of receiving the request.
1c) HV demand: For a new demand connection to the licensee's distribution system where the highest voltage of the assets at the point of connection and any associated works is more than one kV but not more than 22 kV.	Within 20 working days of receiving the request.
1d) HV generation: For a new generation connection to the licensee's distribution system where the highest voltage of the assets at the point of connection and associated works is more than one kV but not more than 22 kV.	Within fifty working days of receiving the request.
1e) EHV demand: For a new demand connection to the licensee's distribution system where the highest voltage of the assets at the point of connection and associated works is more than 22 kV but nor more than 72 kV.	Within fifty working days of receiving the request
1f) Other connections: For a new demand connection or generation connection to the licensee's distribution system that is not included within the preceding sub-paragraphs.	Within three months of receiving the request.

Table 6 - SLC 15 - Final works and phased energisation

Service	Required standard (to be achieved within 90 per cent of all cases)
3a) Low voltage connections: Complete the final works for a low voltage connection	Within 10 working days of receiving the request
3b) High voltage connections: Complete the final works for a high voltage connection	Within 20 working days of receiving the request

Service	**Required standard (to be achieved within 90 per cent of all cases)**
3c) Extra high voltage connections: Inform the applicant of the date by which it is proposed to complete the final works for an extra high voltage connection	Within 20 working days of receiving the request (and complete the works as soon as reasonably practicable
3d) Low voltage energisation: Complete the works required for a low voltage phased energisation.	Within 5 working days of receiving the request.
3e) High voltage energisation: complete works required for a high voltage phased energisation.	Within 10 working days of receiving the request

Table 7 - Summary of regulatory protection for non-competitive electricity connections customers

	LV small scale domestic	**Remaining LV market**	**HV market**	**EHV market**	**Unmetered connections**
Provision of quotations	Guaranteed standard for single premise connections[37] & three months backstop from licence[38]	Guaranteed standard for single premise connections[39] & three month backstop from licence[40]	three month backstop from licence[40]	three month backstop from licence[40]	three month backstop from licence[40]
Completion of connections	Informal monitoring[39]	Informal monitoring[41]	No	No	No
Authority determination	Yes	Yes	Yes	Yes	Yes
Ombudsman powers of investigation	Yes	Domestic and micro-businesses only	No	No	No
Key Performance Indicator regime	No	No	No	No	Yes – for new connections and fault reporting

[37] EGS3 Estimating charges for connection, SI 2005 No.1019 The Electricity (Standards of Performance) Regulations 2005.
[38] Standard licence condition 12.6(c) of the Electricity Distribution Licence.
[39] Quality of Service Regulatory Instructions and Guidance, Version 5, March 2005 Ref:94/05.

Table 8 - DNO market shares by number of connections 2007-08[40]

	LV	HV	EHV	DG
CN West	90%	24%	-	100%
CN East	96%	17%	0%	100%
ENW	65%	82%	-	100%
NEDL	97%	100%	-	88%
YEDL	94%	100%	-	80%
WPD S Wales	99%	100%	100%	100%
WPD S West	100%	100%	-	100%
EDF EPN	100%	91%	100%	87%
EDF LPN	100%	97%	-	-
EDF SPN	99%	83%	-	100%
SP Distribution	46%	35%	-	100%
SP Manweb	62%	72%	-	100%
SSE Hydro[41]	100%	-	-	100%
SSE Southern[42]	99%	-	-	100%

- denotes zero connections undertaken

Guaranteed standards of performance

1.22. Our views on the necessary changes to the standards are set out below taking into consideration consultation responses, our consumer research findings and current performance against the standards.

GS2 Supply restoration - normal conditions

1.23. Initial findings from our consumer research indicated that both business and domestic customers consider the current 18 hour restoration standard is too lenient. Although the follow up willingness to pay research indicated that consumers value rapid restoration of supplies highly, it did not identify a willingness on behalf of consumers to pay more to tighten the standard.

1.24. DNOs report performance against the guaranteed standards to Ofgem on an annual basis. Failures under the EGS2 restoration standard have been minimal as demonstrated by table 9 below. Taking into account recent performance levels it is unlikely that tightening the 18 hour standard would improve protection for many

[40] For details of competition in unmetered connections please refer to Connections Industry Review 2007-08: Appendix 8 (143/08)
[41] SSE is unable to disaggregate LV and HV connections.
[42] SSE is unable to disaggregate LV and HV connections.

additional customers. Also, we are mindful that tightening the standard may have limited impact on DNOs' restoration performance. Given the safety and environmental implications of night working and lack of technological advances to support improvements in restoration times, it is unlikely that DNOs would be able to achieve improvements at a cost that provides value for money to customers. As such, we propose maintaining the current standard of 18 hours and continuing to monitor performance closely.

Table 9 - Percentage of unplanned interruptions lasting 18 hours or more during normal weather

	Total number of unplanned customer interruptions	Total number of unplanned customer interruptions lasting more than 18 hours in normal weather	Percentage of unplanned interruptions lasting more than 18 hours
2005-06	19,547,005	19,290	0.1%
2006-07	20,532,937	36,099	0.2%
2007-08	20,323,610	45,861	0.2%

1.25. DNO respondents expressed concerns over their unlimited exposure to compensation payments EGS2 and suggested that exposure should be capped to limit DNOs' risk during large scale events. Currently under EGS2 DNOs are exposed to £50 for domestic customers and £100 for non-domestic customers for failing the restoration standard and a further £25 for each additional 12 hour period that the customer is off supply with no cap on total compensation for individual customers. Conversely, DNOs' exposure to compensation payments under the severe weather guaranteed standard (EGS11) is capped at £200 per customer. Furthermore, DNOs' exposure to penalties under the interruption incentive scheme (IIS) is capped at 3 per cent of revenue. Further discussion of this issue and potential ways of addressing it are outlined in the IIS section of this appendix.

Guaranteed standard on complaint handling

1.26. The initial consultation document sought views on whether a guaranteed standard on complaint handling should be introduced for DNOs as it has been in gas. We consider that complaint handling is an important aspect of customer service and an area that we expect companies to be focusing on, particularly post-energywatch. We remain concerned about the level of complaints regarding connections that we receive from customers and competitive providers. On 1 October 2008 a new complaint handling standard came into force under the CEAR Act[43] ('the CEAR standard'). We expect the CEAR standard to provide an incentive for DNOs to handle complaints effectively and we will monitor companies' performance against this standard closely. We also intend that the new customer satisfaction metric will

[43] Consumers, Estate Agents and Redress Act 2007.

provide further impetus for DNOs to focus on complaint handling. We intend to collect information from DNOs regarding their compliance with the CEAR standard, including on connections, and by the end of regulatory year 2009-10 we expect to have sufficient information to judge whether DNOs have responded to the new requirement effectively and whether any further action by Ofgem is required. We intend to discuss the scope of our information request with Consumer Focus. If performance is inadequate under the CEAR standard we may seek to introduce a new guaranteed standard similar to that in gas.

Treatment of business customers

1.27. In response to the initial consultation document we received a number of representations from business customers seeking better information, improved reliability of supply, tougher penalties and increased compensation. Our consumer research highlighted that business customers are willing to pay more on top of their current bills to achieve improvements in restoration times. We have also taken account of views put forward by most DNOs that businesses have the option of enhancing the security of their connection or taking out insurance to protect against financial loss caused by power cuts.

1.28. We understand that business customers expect treatment and commercial terms from DNOs akin to what they would be offered in other markets. We also accept that the guaranteed standards regime, which was designed with the interests of domestic customers in mind, may not deliver the redress sought by major energy users. Non-guaranteed standard approaches to addressing business customers' concerns are set out in the IIS section of this appendix.

Other issues

1.29. Although we do not advocate increasing the value of compensation attached to any of the standards, we propose updating the compensation levels to take account of inflation over the past three years. The levels we propose are set out in table 10 below. Current levels of compensation are shown in brackets.

Table 10 - Proposed compensation values as adjusted by inflation rate factor since DPCR4

Reporting code	Service	Performance Level	Penalty Payment
GS1	Respond to failure of distributors fuse (Regulation 10)	All DNOs to respond within 3 hours on a working day (at least) 7 am to 7 pm, and within 4 hours on other days between (at least) 9 am to 5 pm , otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers

Reporting code	Service	Performance Level	Penalty Payment
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made	£54 (£50) for domestic customers and £108 (£100) for non-domestic customers, plus £27 (£25) for each further 12 hours
GS2A*	Supply restoration: multiple interruptions (Regulation 9)	If four or more interruptions each lasting 3 or more hours occur in any single year (1 April – 31 March) , a payment must be made	£54 (£50) for domestic and non- domestic customers
GS3	Estimate of charges for connection (Regulation 11)	5 working days for simple work and 15 working days for significant work, otherwise a payment must be made	£43 (£40) for domestic and non- domestic customers
GS4*	Notice of planned interruption to supply (Regulation 12)	Customers must be given at least 2 days notice, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS5	Investigation of voltage complaints (Regulation 13)	Visit customer's premises within 7 working days or dispatch an explanation of the probable reason for the complaint within 5 working days, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS8	Making and keeping appointments (Regulation 17)	Companies must offer and keep a timed appointment, or offer and keep a timed appointment where requested by the customer, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS9	Payments owed under the standards (Regulation 19)	Payment to be made within 10 working days, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS11*	Supply restoration: severe weather conditions (Regulation 6)	Depending on category of event supply must be restored within 24, 48 or a multiple of 48 hours (see table 2.2 below), otherwise a payment must be made	£27 (£25) for domestic and non domestic customers, plus £27 (£25) for each further 12 hours up to a cap of £216 (£200) per customer

Reporting code	Service	Performance Level	Penalty Payment
GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	£54 (£50) for domestic customers and £108 (£100) for non-domestic customers, plus £27 (£25) for each further 12 hours

* Customers are required to make a claim under these standards. Payments are automatic under other standards.

1.30. In the interests of better regulation, we are keen to ensure that existing standards do not create an unnecessary regulatory burden on DNOs as may be the case if failures against particular standards are minimal. Table 8 in appendix 7 of the initial consultation document sets out number and value of payments made by all DNOs against the guaranteed standards in 2005-06 and 2006-07. We are interested to hear from respondents as to whether any of the current guaranteed standards are unnecessary and should therefore be dropped.

Customer service reward scheme

1.31. This initiative was introduced at DPCR4 to reward DNOs that demonstrate best practice for consumers in areas that cannot be easily measured or incentivised through more mechanistic regimes. Embedding best practice identified during DPCR4 is an important objective for the scheme as we move towards DPCR5. The options for delivering this are set out below and we invite views on the preferred option.

Option 1 - Incorporate best practice examples into the minimum requirements

1.32. The examples of best practice established during DPCR4 could be incorporated into the minimum requirements of the scheme so that DNOs must demonstrate having met them before being considered for a reward. This would raise the bar for DPCR5 performance but may deter DNOs from entering the scheme if they have not adopted all aspects of best practice but perhaps still have valuable contributions to make. One way around this could be to stipulate that a certain proportion of best practice must be met in order to get further rewards.

Option 2 - Incorporate best practice requirements into the licence

1.33. This would make the adoption of best practice mandatory and ensure that all customers benefit from best practice identified at DPCR4. Some of the best practice examples recognised by the scheme may not readily lend themselves to becoming rigid obligations (i.e. commitment and involvement of senior level staff). As such, the obligation could be phrased to allow DNOs to interpret how best practice examples are translated into their businesses. A licence obligation requiring the DNOs to keep appraised of and adopt best practice with regard to serving priority customers may achieve this.

Table 11 - Summary of rewards made under the customer service reward scheme to date

Rewards		
2005-06	Priority customer care	
	Shared by EDF Energy and WPD (£300,000 each)	▪ Work with suppliers and energywatch to improve Priority Service Register and raise awareness of available services. ▪ Support offered to priority customers during interruptions, such as regular updates and additional assistance. ▪ EDF Energy was also commended for its proactive customer research and for incorporating this into staff training to improve services.
	Corporate social responsibility (CSR)	
	WPD (£200,000)	▪ Breadth and depth of initiatives, good governance procedures and holistic approach. ▪ E.g. Staff participation in educational projects which relate to the industry and its work.
2006-07	Priority customer care	
	Shared by CE Electric and EDF Energy (£300,000 each)	▪ Demonstration of the impact of initiatives on customers. ▪ Recognition of the need to serve temporarily vulnerable customers. ▪ Work to update records and provide customers with additional services. ▪ Staff training from relevant organisations. ▪ CE Electric was also commended for its treatment of disabled customers and for senior management involvement in its priority customer care programme. ▪ EDF Energy was also praised for its work with a disability charity to build knowledge of customer needs and for its contact with vulnerable groups through talking newspapers and hospital radio.
	Wider communication strategies	
	CE Electric (£400,000)	▪ Language line providing translation into over 100 languages. ▪ Distribution of update newsletters to parish councils. ▪ Work with community groups, MPs and media to raise customer awareness.
2007-08	Corporate social responsibility	
	Central Networks and EDF Energy (£350,000	▪ Exceeding obligations within local communities to mitigate the environmental and social impacts of electricity networks. ▪ Wider business commitment to CSR, senior level engagement and innovative initiatives demonstrated.

Rewards		
	each)	
	Wider communication strategies	
	Central Networks and WPD (£150,000 each)	▪ Responding to the specific communication needs in their communities, in particular hard to reach customers. ▪ Wider business commitment to communicating with hard to reach customers and senior management engagement with the cause.

Table 12 - Summary of best practice examples from the customer service reward scheme to date

Best practice
Corporate social responsibility (CSR)
▪ Staff induction programmes to improve the local community.
▪ Active participation in the community and establishment of links with other agencies/stakeholders.
▪ A strategic approach to CSR with active senior management involvement and commitment above and beyond reporting responsibility.
▪ A range of initiatives related to the business such as addressing potential skill shortages, mitigating environmental impacts, safety awareness campaigns and initiatives to prevent doorstep crime.
▪ Inclusion of contractor performance within the company's CSR programme and active encouragement of staff involvement.
▪ Partnership work with local organisations to provide training and development opportunities for disadvantaged young people.
Priority customer care
▪ Partnerships with voluntary groups or parish councils to offer support during power interruptions.
▪ Customer support vehicles and winter packs to provide assistance during interruptions.
▪ Customer research to better identify the needs of priority customers.
▪ Initiatives to ensure priority customers are kept informed of progress or offered assistance during unplanned interruptions.
▪ Partnership with a home oxygen equipment provider to raise awareness of the Priority Service Register among oxygen dependent customers and co-ordinate emergency care.
▪ Work with community partners to expand the Priority Service Register and initiatives to ensure information is accurate and up to date.
▪ Active promotion of the Priority Service Register.
▪ Work with relevant organisations to ensure that staff are properly trained to help vulnerable customers.
▪ Commitment and involvement of senior staff.

Best practice
Wider communication strategies
▪ Work with local radio to reinforce and extend coverage, enabling radio updates during storms and power interruptions.
▪ Other partnership work with parts of the community, such as Post Offices, MPs and media.
▪ Proactive use of materials and communication techniques such as easy-to-read, audio and Braille formats.
▪ Proactive use of customer complaints and customer research.
▪ Provision of live network information during interruptions enabling customers to check estimated restoration times.
▪ Media training for key staff members.
▪ Initiatives that recognise the specific communication needs of the company's particular communities including hard to reach customers
▪ Use of employee feedback in targeting communication strategies
▪ Sharing established partnerships with other DNOs to facilitate the sharing of best practice
▪ Bespoke customer service training initiatives to empower staff to respond to the needs of customers with learning difficulties.

Worst served customers

1.34. Ofgem is looking at ways to incentivise DNOs to improve the service given to worst served customers.

1.35. Ofgem considers that changes to the guaranteed standards of performance would be unlikely to deliver the desired outcome of improvements in performance for worst served customers and would principally result in changes in the level of compensation. As worst served customers represent such a small proportion of the total customer base, the cost of improvement programmes would outweigh the cost of reasonable penalty payments. Therefore, the customers would continue to receive additional penalty payments but would most likely see little or no improvement in performance. We do not consider that changes to the GS are an appropriate mechanism for improving performance to worst served customers. Ofgem invites views on this conclusion.

1.36. As discussed in chapter 3, we have investigated both a defined allowance for improving worst served customers and an incentive approach. A set allowance is proposed with the possibility of incorporating or moving toward an incentive in the future.

1.37. In DPCR4 the DNOs were given interruption cost allowances. These allowances were split between capex and opex and totalled approximately £225 million over the five year period. If similar allowances were to be provided in DPCR5 it may be possible to set aside a proportion specifically for the worst served customers.

Customer numbers

1.38. It is important to develop an appropriate definition of worst served customers. Both customer interruptions and customer minutes lost were investigated and are discussed in chapter three. Three potential methods for defining the worst served customers are given below. Due to the limits on the information available through current outage monitoring systems, it was decided that only higher voltage interruptions would be considered. Information from the first three years of DPCR4 was used:

- Customer interruptions per year experienced by a given percentage of the total Customer Base (0.5 per cent or 1 per cent)
- The number of customers experiencing greater than or equal to a given number of interruptions per year (5,7,8,9 or 10)
- Customer interruptions per year experienced by a fixed number of customers (1000, 2000, 3000, 4000 and 5000)

Table 13 - Customer numbers for various definitions of worst served customer

	Customers experiencing greater than or equal to X interruptions					**X per cent of total customer base**	
X	5	7	8	9	10	0.5%	1.0%
CN West	67,051	15,849	8,194	4,329	1,398	12,077	24,155
CN East	36,890	7,390	3,275	1,600	683	12,746	25,491
ENW	19,383	4,483	2,576	954	680	11,626	23,252
CE NEDL	11,326	1,363	879	122	46	7,746	15,493
CE YEDL	15,010	2,593	509	177	37	11,126	22,253
WPD S Wales	27,518	8,398	5,387	3,339	1,350	5,403	10,807
WPD S West	22,528	5,323	2,039	980	395	7,491	14,982
EDFE LPN	-	-	-	-	-	11,067	22,135
EDFE SPN	33,477	4,070	1,515	729	184	11,090	22,181
EDFE EPN	17,147	3,639	1,627	936	125	17,288	34,577

	Customers experiencing greater than or equal to X interruptions					**X per cent of total customer base**	
SP Distribution	22,638	5,914	3,039	1,894	1,300	9,938	19,877
SP Manweb	12,761	2,622	1,223	647	417	7,398	14,796
SSE Hydro	25,368	7,889	4,673	2,446	1,446	3,552	7,104
SSE Southern	26,803	4,582	2,102	1,055	295	14,245	28,490
Total	337,900	74,116	37,039	19,206	8,355	142,795	285,590

Note: This information in the table above was based on the average of three years worth of DPCR4 frequency of interruption information. Due to the limitations of this information, it should not be assumed that the same customers experience these interruptions each year.

1.39. The level of performance within a given percentage of total customer base, can vary significantly. Furthermore, the fluctuation in total customer base adds further volatility. We consider the most appropriate definition of worst served customers is those customers that experience greater than or equal to a given number of interruptions within a year. We propose a threshold of greater than or equal to five interruptions (on average over a three year period) to be most appropriate. This balances the impact of performance for such customers with the overall numbers allowing specific circuits to be targeted.

Defined allowance

1.40. Various options were investigated for determining an appropriate allowance. These options were:

- Allowance based on undergrounding - average cost per customer for undergrounding in National Parks and AONBs (Option 1),
- Allowance based on worst served customer project proposals - Average cost per benefiting customer (Option 2), and
- Allowance based on an upper limit for cost per benefiting customer. Based on similar amounts to those already paid for quality of service (Option 3).

1.41. The first option uses the costs submitted for undergrounding schemes undertaken in DPCR4. Project costs for various proposed undergrounding projects were used to determine an average cost per customer (total customer base for all

DNOs excluding EDFE LPN). This average cost was then used to calculate the total allowance for various worst served customer bases. The customer bases were defined in terms of percentage of total customer base (0.5 per cent or 1 per cent), number of interruptions experienced (greater than or equal to 7, 8, 9 and 10) and fixed customer number (1,000, 2,000, 3,000, 4,000 & 5,000).

1.42. This option was considered to be too expensive both in terms of cost per total customer and per benefiting customer.

1.43. The second option involved taking the average cost per benefiting customer from worst served customer project proposals put forward by DNOs. One DNO used real circuits that had been classified as worst served through a variety of definitions. The DNOs then had a suite of improvement projects and their associated costs. Across all of the projects costs put forward, the average cost per benefiting customer was in the region of £2,000. This cost is disproportionately high compared to the amount that every customer currently spends on quality of service.

1.44. The final option involved setting an upper limit on the cost per benefiting customer. It was believed that the cost per benefiting customer should be in the same order that all customers currently pay for quality of service. The information was based on the net reward/penalty information from the IIS in DPCR4 along with the capex and opex allowances. The costs also took into consideration the opex costs that would be saved as a result of a decrease in interruptions. The total costs were calculated over both the five year DPCR5 period and the assumed 20 year life of the asset.

1.45. This option was seen found to be the most reasonable way of setting the total allowance. The option gave a value of £42 million across all of the DNOs.

1.46. There are a variety of ways in which the allowance could be structured and some of the options considered were:

- Common allowance for all DNOs (option 1),
- Varied allowance based on total customers (option 2),
- Varied allowance based on number of worst served customers(option 3),
- Varied allowance based on worst served customers as a percentage of the total customer base (option 4).

Table 14 - Allowance distribution options

	Customers with >=5 interruptions per year (3 year average)	Total customers	£m Option 1	£m Option 2	£m Option 3	£m Option 4
CN West	67,051	2,415,484	8%	9%	20%	15%
CN East	36,890	2,549,112	8%	10%	11%	8%
ENW	19,383	2,325,155	8%	9%	6%	4%
CE NEDL	11,326	1,549,259	8%	6%	3%	4%
CE YEDL	15,010	2,225,253	8%	8%	4%	4%
WPD S Wales	27,518	1,080,697	8%	4%	8%	14%
WPD S West	22,528	1,498,199	8%	6%	7%	8%
EDFE LPN	0	2,213,479	0%	0%	0%	0%
EDFE SPN	33,477	2,218,054	8%	8%	10%	8%
EDFE EPN	17,147	3,457,682	8%	13%	5%	3%
SPD	22,638	1,987,679	8%	8%	7%	6%
SPM	12,761	1,479,569	8%	6%	4%	3%
SSE Hydro	25,368	710,383	8%	3%	8%	19%
SSE Southern	26,803	2,848,956	8%	11%	8%	5%
Total	33,7900	28,558,962	100%	100%	100%	100%

1.47. Table 14 gives an overview of the various options. There are two major considerations when distributing the allowance. Firstly, it is important that each DNO would receive enough of an allowance to create some schemes that would be able to deliver an improvement. Secondly, it is important to ensure that the customers are not too disadvantaged by the total customer base of their respective DNO or their proportion of worst served customers. With these considerations in mind, Ofgem proposes Option 1 be adopted.

Worst served customer mechanism

1.48. As part this approach, DNOs will be required to submit their proposed worst served customer schemes for approval by Ofgem. From the second year of DPCR5 onward, they will also be required to include an update on completed schemes as part of their submissions. Our initial thoughts on the rules for submissions under this mechanism are listed below:

- The customers benefiting from the proposed projects should have experienced on average greater than or equal to five interruptions per year over the past three years,
- The proposed projects could be pre-existing projects that have been brought forward in order to accelerate the performance improvement for worst served customers,
- DNOs should only submit schemes that achieve a minimum performance improvement of 25 per cent for the targeted customers. Failure to deliver on this improvement could result in adjustments to their future allowance or some recovery of past allowances,
- The average cost per benefiting customer should not exceed £X (a number to be determined) over all projects in DPCR5,
- The £X (a number to be determined) can be calculated based on the net present value (NPV) difference between the original planned date and the accelerated date of a particular project for worst served customers,
- The £X (a number to be determined) should also be calculated taking into account the reduced opex resulting from the proposed reduction in interruptions (i.e. the additional benefit should be netted off).

1.49. We accept that the overall mechanism may need reviewing after the first four years in 2014-15 with a view to inputting into DPCR6. The purpose of the proposals is to provide relative information on the types of projects being implemented and also to ensure that the guidelines have been considered. Given that there is high variability in the costs associated with various schemes, Ofgem proposes to allow the expenditure to be an average cost per benefiting customer. This should allow the DNOs the ability to balance more expensive solutions with less expensive ones. Ofgem proposes that the £X (a number to be determined) per customer is an average over all projects over the entire period. Ofgem invites views on what £X (a number to be determined) per customer should be used.

Interruptions incentive scheme

Review of amendments to the benchmarking methodology

1.50. This section discusses amendments to our approach for benchmarking customer interruptions (CIs) and customer minutes lost (CMLs).

HV

1.51. As outlined in the initial consultation document, we have more years' data with which to carry out the HV benchmarking than was available for DPCR4. By summer next year we will have seven years worth of data available. DNOs suggested either the most recent three years data be used, as was the case for DPCR4 benchmarking, or that five years data be used. Extending the period can dampen year on year volatility but it can also reduce the impact of more recent performance improvements. At this stage we are using the most recent three years' data and are inclined to extend this to four years for the final targets, such that we are using a longer period than previously and all the years' data are based on a consistent set of rules and incentives.

1.52. DNOs have suggested a number of modifications to the disaggregation and benchmarking methodology[44] as explained below. The impact of the changes is shown in table 16 and table 17.

L0 band

1.53. As DNOs have taken different approaches to assigning nominal lengths to zero length circuits we have looked at two possible ways of ensuring consistency across DNOs.

Removing all circuits from the L0 band

1.54. Remove the L0 band from the disaggregation worksheets for the three years of DPCR4 to date by applying a nominal 100 metres length to any zero length circuits. This moves circuits into either the UG1A[45] or UG1B[46] bands, with little overall impact on the benchmarks.

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[44] The comparisons in this section with 'present targets' are those targets discussed with the Quality of Service working group subsequent to the publication of the initial consultation document.
[45] 100 per cent underground circuit of length up to 4km with up to 1000 customer connected.
[46] 100 per cent underground circuit of length up to 4km with greater than 1000 customer connected.

Changing L0 band definition to include circuits of length up to 100.1 metres

1.55. Modify the circuit band definitions so that the L0 band encompasses all circuits up to a length of 100.1 metres. This ensures that zero length and very short circuits are treated separately from the wider population of circuits thereby removing a potential distortion to the benchmarking process. The impact of this approach also has little effect on the targets.

Customer density

1.56. EDF Energy has put forward a case that the current CI benchmarking process does not take account of customer density on each feeder. They have proposed an adjustment to the benchmarking formula to correct for this.

Band dominance/DNO ability to improve fault rates

1.57. Central Networks has suggested that benchmarks in particular bands are dominated by a particular DNO which has superior fault rates. They propose that either the DNO in question is removed from the disaggregation process, or that the current 100 per cent weighting given to industry average fault rate is reduced, particularly for the underground bands where DNOs are less likely to be able influence the fault rates without very high levels of investment.

1.58. A key benefit of the benchmarking methodology is that we are able to compare similar circuits across all 14 DNOs and we are not persuaded of the merits in selectively taking out particular DNOs from the process. We have amended the weighting on fault rates in the benchmarking, to take account of this issue:

- Underground bands (UG) - 80 per cent own; 20 per cent industry,
- Mixed bands (MA) - 60 per cent own; 40 per cent industry,
- Mixed bands (MB) - 40 per cent own; 60 per cent industry,
- Mixed bands (MC) - 20 per cent own; 80 per cent industry,
- Overhead bands (OH) - 0 per cent own; 100 per cent industry.

Reducing linear length correction factor

1.59. A further change suggested by one of the DNOs is to reduce or remove the current one to one performance versus length correction factor applied in the benchmarking. Their analysis suggests that there is an inverse relationship between length and performance for circuits in the UG1 band, which may be being partially affected by the inclusion of zero length circuits and that whilst the relationship in the other bands between length and performance is positive, it is at a rate of about one third of that implied by a linear length correction. Changing the definition of the L0 band to circuits up to 100.1 metres in length in order to capture all the zero length circuits which DNOs had applied a nominal length to should address this, although we intend to carry out further work to determine what the appropriate length correction factor should be for determining the DPCR5 benchmarks.

Calculating the upper quartile

1.60. DNOs have commented that the methodology for determining upper quartile performance should be altered. The methodology used for DPCR4 and embedded in the initial consultation draft targets based upper quartile performance on the upper quartile within each of the 23 circuit bands. The DNOs have suggested that achieving upper quartile performance across all bands is unrealistic and have proposed that the data be summed across all the bands first and then used to derive the upper quartile. We are considering this further, although we note that two of the DNOs outperform the upper quartile in most of the bands. We invite views on how the upper quartile should be derived.

LV

1.61. As set out in the initial consultation document we are proposing to benchmark the number and duration of interruptions at the total LV level. Whilst this approach has attractions in terms of simplicity and addressing differences in reporting mains and service interruptions, a number of respondents have expressed concern that our proposed approach does not take into account DNOs with a higher proportion of underground circuits compared to overhead. Given current reporting arrangements it may not be possible to achieve a clean split into just these two categories, as there are other categories of interruptions which do not necessarily map across, such as switchgear/fusegear. Table 15 below shows the percentage of CI by current LV reporting category. Given the likely complications with trying to split LV interruptions into revised categories we propose to continue with a total LV approach. We invite views on our proposed approach.

Table 15 - Percentage of CI by current LV reporting category

DNO	LV Overhead Mains	LV Underground Mains	LV Switchgear /fusegear	LV Services	LV all other
CN West	7%	48%	1%	27%	18%
CN East	4%	34%	45%	8%	9%
ENW	2%	83%	2%	13%	0%
CE NEDL	3%	42%	3%	16%	36%
CE YEDL	2%	43%	3%	24%	28%
WPD S Wales	13%	38%	24%	21%	3%
WPD S West	13%	31%	37%	18%	2%
EDFE LPN	5%	64%	7%	22%	1%
EDFE SPN	6%	27%	36%	29%	3%

DNO	LV Overhead Mains	LV Underground Mains	LV Switchgear /fusegear	LV Services	LV all other
EDFE EPN	14%	65%	6%	15%	1%
SPD	2%	44%	34%	19%	0%
SP Manweb	10%	44%	24%	23%	0%
SSE Hydro	12%	53%	6%	27%	2%
SSE Southern	8%	78%	1%	12%	0%

EHV/132kV

1.62. As set out in the initial consultation document we propose to use data from 2002-03 onwards adjusted for the customer numbers for the respective years to set the EHV and 132kV benchmarks. We have received responses relating to large one-off events which do not meet the current one-off exceptional events criteria for exclusion and their potential impact on both IIS and guaranteed standards. DNOs have suggested that given this combined exposure they may in certain circumstances 'over-engineer' a scheme in order to mitigate the potential risk of a three per cent IIS penalty and unlimited GS payments.

1.63. For example, as part of the planned replacement of a transformer at a two transformer substation, a DNO could look to alleviate the reduced security by constructing a temporary transformer next to the existing site, or even look to install a third permanent transformer before the planned replacement. Factoring in the uncapped potential liability under the normal weather guaranteed standard may, in certain circumstances, lead to uneconomic expenditure. We are interested to hear views on whether it is appropriate to limit exposure to EHV/132kV events. Possible options to deal with this are:

- Apply a reduced weighting to 132kV and EHV incidents, reflecting DNOs' reduced ability to readily influence these incidents,
- Apply a cap per incident on 132kV and EHV incidents (this could be in terms of fixed value per DNO, return on equity, or the same thresholds as the existing one-off mechanism),
- Broaden the scope of the one-off exceptional events criteria to include incidents 'within the control' of the DNO i.e. incidents due to equipment failure - we would still have the ability to reject a claim if the examiner felt that the DNO had not taken all appropriate mitigating actions before and after the event.

1.64. For customers however, the impact will not vary between different voltages of unplanned interruptions and as such it is debatable as to whether the incentive scheme should do so. Whilst a reduced weighting is applied to the minutes lost associated with interruptions from NGET and other connected networks, this is because these networks are outside of the DNOs' control. The reduced weighting applied to planned interruptions is a result of feedback from our customer research and is intended to reflect the reduced disruption felt by customers when they have been pre-notified of an interruption.

Revised draft 2014-15 benchmarks

1.65. A number of DNOs expressed concern that the DPCR4 benchmarking methodology and that outlined in the initial consultation document would effectively penalise frontier HV CI DNOs when it came to setting their HV CML targets. We have reviewed the impact on frontier HV CI performers of using their own HV CI performance to set their HV CML benchmarks and believe that it is appropriate to amend the HV CML benchmarking for frontier HV CI DNOs, such that an 'assumed' 2014-15 HV CI benchmark is calculated and then used to derive the HV CML benchmark.

1.66. For the HV element of the unplanned targets in the main document we have modified the L0 band definition and applied the changes for both customer density and band dominance. We have also based HV CML benchmarks for frontier HV CI DNOs on their 'assumed' 2015 HV CI benchmarks. We have not applied the change to the upper quartile methodology for CML. The amended benchmarks in tables 16 and 17 reflect the lower of either benchmark or three year average overall unplanned performance.

1.67. The impacts of the changes outlined above on draft unplanned CI and CML targets are shown in table 16 and table 17.

Table 16 - Amended 2014-15 unplanned CI benchmarks based on proposed changes

	Before methodology changes	Lo Band removed	Lo = 100.1	Customer density, no Lo	Customer density, Lo = 100.1	Fault rates, no Lo	Fault rates, Lo = 100.1	Fault rates & customer density, no Lo	**Fault rates & customer density, Lo = 100.1**
CN West	101.1	101.1	101.1	101.3	101.3	102.3	102.3	103.1	**103.1**
CN East	70.0	70.0	70.0	69.8	69.8	70.4	70.4	70.7	**70.6**
ENW	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	**50.8**
CE NEDL	64.0	64.0	64.0	64.0	64.0	63.3	63.3	63.6	**63.6**
CE YEDL	67.4	67.4	67.4	67.3	67.3	66.8	66.9	67.2	**67.1**
WPD S Wales	70.6	70.6	70.5	70.5	70.4	72.7	72.7	73.1	**73.0**
WPD S West	73.1	73.2	73.1	73.1	73.1	73.4	73.5	73.7	**73.7**
EDFE LPN	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	**33.0**
EDFE SPN	74.4	74.2	74.4	74.8	74.9	76.5	76.6	77.7	**77.6**
EDFE EPN	70.0	70.0	69.9	69.7	69.7	70.1	70.0	70.2	**70.1**
SP Distribution	57.9	58.0	57.9	57.8	57.8	58.4	58.4	58.8	**58.7**
SP Manweb	42.3	42.3	42.3	42.3	42.3	42.3	42.3	42.3	**42.3**
SSE Hydro	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3	**68.3**
SSE Southern	70.5	70.5	70.5	70.3	70.4	70.3	70.3	70.5	**70.5**

Table 17 - Amended 2014-15 unplanned CML benchmarks based on proposed changes

	Before methodology changes	Lo Band removed	Lo = 100.1	Customer density, no Lo	Customer density, Lo = 100.1	Fault rates, no Lo	Fault rates, Lo = 100.1	Fault rates & customer density, no Lo	**Fault rates & customer density, Lo = 100.1**	Fault rates & customer density, No Lo, upper quartile
CN West	78.9	78.9	78.8	79.0	78.9	79.4	79.3	79.7	**79.7**	84.9
CN East	57.3	57.3	57.2	57.2	57.1	57.3	57.2	57.5	**57.3**	60.7
ENW	48.1	48.2	47.9	48.1	47.9	47.6	47.2	48.2	**47.7**	50.9
CE NEDL	55.6	55.6	55.5	55.7	55.6	55.3	55.2	55.5	**55.4**	57.3
CE YEDL	60.9	60.9	60.8	60.9	60.8	60.6	60.5	60.7	**60.6**	63.7
WPD S Wales	39.9	39.9	39.9	39.9	39.9	39.9	39.9	39.9	**39.9**	39.9
WPD S West	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	**43.2**	43.2
EDFE LPN	44.7	44.6	44.6	44.7	44.6	38.1	38.1	38.5	**38.5**	43.0
EDFE SPN	56.9	56.8	56.7	57.1	56.9	57.9	57.8	58.5	**58.3**	65.0
EDFE EPN	55.2	55.2	55.1	55.0	55.0	55.0	55.0	55.1	**55.0**	57.5
SP Distribution	50.3	50.3	50.1	50.2	50.0	50.6	50.4	50.8	**50.6**	52.3
SP Manweb	45.0	45.1	45.0	45.4	45.3	48.6	48.6	50.0	**49.8**	51.8
SSE Hydro	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	**58.6**	58.6
SSE Southern	58.5	58.6	58.4	58.5	58.4	58.4	58.3	58.5	**58.4**	61.0

Starting points and glide paths for DPCR5 unplanned targets

1.68. The starting point for DPCR5 will be the lower of either their three year average performance or their unplanned 2009-10 target. The 2014-15 unplanned target will be the lower of either their amended benchmark for 2014-15 or their 2009-10 target.

1.69. The glide-path from the starting point to the 2014-15 target will be, where improvement is required, based on a uniform annual improvement. E.g. a five CI improvement across DPCR5 would mean a tightening of the CI target by one CI each year over the course of DPCR5. The overall impact of the changes outlined above results in draft unplanned CI and CML targets set out in table 18 and table 19.

Table 18 - Draft unplanned CI targets for DPCR5

	Current 3yr average	2009/10	**Start Point**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CN West	111.2	100.1	100.1	100.1	100.1	100.1	100.1	100.1
CN East	75.6	74.0	74.0	73.3	72.6	72.0	71.3	70.6
ENW	50.8	56.4	50.8	50.8	50.8	50.8	50.8	50.8
CE NEDL	64.0	71.0	64.0	63.9	63.9	63.8	63.7	63.6
CE YEDL	73.5	66.6	66.6	66.6	66.6	66.6	66.6	66.6
WPD S Wales	77.8	85.9	77.8	76.8	75.9	74.9	74.0	73.0
WPD S West	73.9	80.6	73.9	73.9	73.8	73.8	73.7	73.7
EDFE LPN	33.0	35.4	33.0	33.0	33.0	33.0	33.0	33.0
EDFE SPN	82.9	81.3	81.3	80.5	79.8	79.1	78.4	77.6
EDFE EPN	70.8	83.2	70.8	70.7	70.5	70.4	70.2	70.1
SP Distribution	59.3	59.5	59.3	59.2	59.1	59.0	58.8	58.7
SP Manweb	42.3	45.2	42.3	42.3	42.3	42.3	42.3	42.3
SSE Hydro	68.3	88.7	68.3	68.3	68.3	68.3	68.3	68.3
SSE Southern	71.1	84.7	71.1	71.0	70.8	70.7	70.6	70.5

1.70. We recognise that the DPCR4 methodology for setting the 2009-10 CML targets applied benchmark CML/CI to actual CI in some cases which differs from our proposed approach for DPCR5. As such we have recast the 2009-10 CML targets based on the DPCR5 approach for EDFE LPN and SP Manweb, as these were tighter than their three year average performance, in order to determine the appropriate glide path for the DPCR5 CML targets.

Table 19 - Draft unplanned CML targets for DPCR5

	Current 3yr average	2009/10	**Start Point**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CN West	89.7	80.4	80.4	80.2	80.1	79.9	79.8	79.7
CN East	65.5	61.4	61.4	60.6	59.8	59.0	58.1	57.3
ENW	48.7	51.2	48.7	48.5	48.3	48.1	47.9	47.7
CE NEDL	58.2	59.8	58.2	57.6	57.1	56.5	55.9	55.4
CE YEDL	68.0	57.6	57.6	57.6	57.6	57.6	57.6	57.6
WPD S Wales	39.9	61.0	39.9	39.9	39.9	39.9	39.9	39.9
WPD S West	43.2	55.4	43.2	43.2	43.2	43.2	43.2	43.2
EDFE LPN	39.1	43.4	39.1	39.0	38.8	38.7	38.6	38.5
EDFE SPN	83.8	60.9	60.9	60.4	59.9	59.3	58.8	58.3
EDFE EPN	62.4	65.3	62.4	61.0	59.5	58.0	56.5	55.0
SP Distribution	66.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1
SP Manweb	53.9	51.1	51.1	50.8	50.6	50.3	50.0	49.8
SSE Hydro	58.6	82.1	58.6	58.6	58.6	58.6	58.6	58.6
SSE Southern	64.8	69.6	64.8	63.5	62.2	60.9	59.6	58.4

Incentive rates and revenue exposure to the scheme

1.71. The division of the three per cent of revenue between CIs and CMLs, currently set at 1.2 per cent and 1.8 per cent respectively has been questioned by one DNO. As CIs are an element of the CML calculation they count for a proportion of the 1.8 per cent in addition to the 1.2 per cent which may place more weight on CIs than customers wish or DNOs are able to deliver. We invite views on the appropriate/preferred split of IIS incentives between CIs and CMLs.

1.72. A number of DNOs have also proposed that equal[47] incentive rates should apply to all DNOs, except where customer research indicates otherwise.

1.73. The DPCR4 methodology for setting the CI and CML incentive rates was based on a fixed percentage of revenue exposure and fixed performance bands around the CI and CML targets. This resulted in significant differences in the CI and CML incentive rates. This is illustrated below:

[47] Equal across DNOs but not necessarily equal between CI and CML

Table 20 - DPCR4 target setting methodology

Element	Constant or varied
Revenue exposure	Constant at 1.2 per cent of revenue
Return on equity	Varied, highest 0.68 per cent, lowest 0.59 per cent
Bandwidth around target	Constant at 25 per cent of target
Incentive rate per CI	Varied, highest £0.327 million, lowest £0.078 million
Incentive rate per customer	Varied, highest £14.77, lowest £4.45
Maximum financial impact per customer	Varied, highest £3.15, lowest £0.98
Impact on average customer DUoS bill	Varied, highest 2.8 per cent, lowest 1.5 per cent

1.74. As explained in the main document differential incentive rates may result in the same initiative intended to deliver the same benefit being economic in one DNO whilst returning a negative NPV in another DNO. As such we have looked at a number of ways to equalise CI and CML incentive rates and the impact this would have on performance bands, incentive rates per customer, revenue exposure and return on equity as set out in table 21, table 22, table 23, and table 24. The examples outlined in this section use CIs to illustrate the effects of the various changes. The effects would also be applicable to CMLs.

Table 21 - Example 1 - use a constant incentive rate per CI:

Element	Constant or varied
Revenue exposure	Constant at 1.2 per cent of revenue
Return on equity	Varied, highest 0.68 per cent, lowest 0.59 per cent
Bandwidth around target	Varied, largest 51 per cent, smallest 12 per cent
Incentive rate per CI	Constant incentive rate of £0.16 million per CI
Incentive rate per customer	Varied, highest £22.53, lowest £4.63
Maximum financial impact per customer	Varied, highest £3.15, lowest £0.98
Impact on average customer DUoS bill	Varied, highest 2.8 per cent, lowest 1.5 per cent

Table 22 - Example 2 use a constant maximum financial impact per customer value of £1.50:

Element	Constant or varied
Revenue exposure	Varied, highest 1.8 per cent, lowest 0.6 per cent
Return on equity	Varied, highest one per cent, lowest 0.28 per cent
Bandwidth around target	Constant at 25 per cent of target
Incentive rate per CI	Varied, highest £0.367 million, lowest

Element	Constant or varied
	£0.044 million
Incentive rate per customer	Varied, highest £16.57, lowest £5.57
Maximum financial impact per customer	Constant at £1.50 per customer
Impact on average customer DUoS bill	Varied, highest 3 per cent, lowest 1.3 per cent

Table 23 - Example 3 use a constant incentive rate per customer of £8.50:

Element	Constant or varied
Revenue exposure	Constant at 1.2 per cent of revenue
Return on equity	Varied, highest 0.68 per cent, lowest 0.59 per cent
Bandwidth around target	Varied, largest 43 per cent, smallest 13 per cent
Incentive rate per CI	Varied, highest £0.294 million, lowest £0.060 million
Incentive rate per customer	Constant at £8.50 per customer
Maximum financial impact per customer	Varied, highest £3.15, lowest £0.98
Impact on average customer DUoS bill	Varied, highest 2.8 per cent, lowest 1.5 per cent

Table 24 - Example 4 use a constant return on equity:

Element	Constant or varied
Revenue exposure	Varied, highest 1.2 per cent, lowest 1.1 per cent
Return on equity	Constant at 0.60 per cent
Bandwidth around target	Constant at 25 per cent of target
Incentive rate per CI	Varied, highest £0.330 million, lowest £0.073 million
Incentive rate per customer	Constant at £8.50 per customer
Maximum financial impact per customer	Varied, highest £3.18, lowest £0.90
Impact on average customer DUoS bill	Varied, highest 2.8 per cent, lowest 1.5 per cent

1.75. Given the draft targets for DPCR5 set out in the main chapter, we believe that, whilst a degree of convergence is required, it remains appropriate to maintain some differential in incentive rates in order to reflect the perceived ease or difficulty in making further performance improvements. As such, a hybrid of the examples above may be appropriate, in order that performance bands, incentive rates per customer, revenue exposure and return on equity do not vary too significantly across DNOs. We may also want to factor in how much customers currently pay for distribution when determining the level of their exposure to IIS.

1.76. Feedback from the customer willingness to pay survey indicated that customers are less tolerant of deterioration in current levels of performance, and would therefore require a greater reduction in their bill, than they would be prepared to pay for an equivalent improvement in service. One option would be to set asymmetric incentive rates, with lower reward incentive rates associated with improvements and higher penalty incentive rates for reductions in performance. Whilst the current scheme has symmetric incentive rates DNOs have commented that they are exposed to greater downside risk, and as such the scheme may already deliver the outcome indicated by the customer research.

1.77. We invite views on which of the variables set out above should be uniform across DNOs and whether we should continue with symmetric rewards and penalties.

Pre-arranged interruptions

1.78. As set out in the initial consultation document, we are looking to better understand the relationship between the work that drives the need for pre-arranged interruptions and the level of pre-arranged interruptions required by the different types of work. We have collected initial information on pre-arranged interruptions as part of the August FBPQ and will be gathering additional information in the main FBPQs due to be submitted in February.

1.79. We would welcome views on the following options:

- Including pre-arranged interruptions in DNOs' targets, with the current reduced weighting. The level to be included would be built up from an analysis of forecast work and the associated interruptions impact. Additionally, we could include a driver so that the targets flex upwards if additional planned work is carried out and downwards if forecast work does not materialise.

- Set a zero allowance for pre-arranged interruptions in DNOs' targets, the costs associated with mitigating pre-arranged interruptions would be included in the capex/opex allowances and pre-arranged interruptions would continue to be exposed to a reduced incentive rate in the scheme.

Treatment of exceptional events

1.80. All DNOs see merit in maintaining the exceptional events mechanism. There was some support for re-introducing a materiality test for severe weather events and doing so would ensure symmetry between one-off and severe weather exceptional events. Such a test would work as now for the one-off event mechanism, whereby only those CI and CML above their respective thresholds would be eligible for exclusion. The impact on DPCR4 claims to date of introducing CI and CML materiality tests set at the same level as the one-off tests would reduce the excluded CI by over half and the excluded CML by a quarter.

1.81. Given that most severe weather events affect overhead networks and therefore draw upon overhead line resources one DNO has suggested that the severe weather thresholds should be based on a multiple of daily average overhead higher voltage incidents, rather than the current multiple of daily average total higher voltage incidents. If we were to move to this methodology then it would also seem appropriate that future severe weather exceptional events only comprise overhead line incidents. They have also suggested updating the threshold on an annual basis. Such changes could also necessitate the recasting of the benchmarking data used for setting the DPCR5 targets. We invite views on whether the severe weather thresholds should be based on overhead line incidents, and if so, whether future severe weather events should be restricted to only overhead incidents. We also invite views on whether the thresholds should be updated annually.

1.82. The same DNO suggested that the current severe weather mechanism could be applied from a lower exceptionality level with a reduced level of exclusion through to a full exclusion at the current Category 2 threshold. They feel that this would mitigate potentially perverse effects on IIS performance of investment in network resilience and would also remove the 'knife-edge' effect of the current 'all or nothing' thresholds. The analysis provided by the DNO indicated that whilst the total number of events that would have passed under their proposal increased substantially, there was little difference in the total CI and CML to be excluded. Additionally, there is significant benefit in customers being given a clear message as to whether and what level of compensation they may be entitled to following severe weather and we would not want introduce a system that hindered this clarity for customers.

1.83. We acknowledge that there can be events at the boundary which are either fully removed or stay entirely in IIS under the current mechanism but believe that the re-introduction of a materiality test should help to alleviate this.

1.84. Amendments to the severe weather thresholds will have an impact on the number and size of exceptional events in DPCR5 and DNOs have suggested that the IIS targets would need to be adjusted accordingly.

1.85. Under the changes to the ESQCR DNOs are required to undertake additional tree cutting work both for continuity of supply and network resilience. Any additional costs arising from these obligations are funded through the DPCR4 reopener and will be taken into account in setting revenue for DPCR5. We are currently considering how this should be taken into account in setting targets for DPCR5 and the exceptional event thresholds.

1.86. We invite views on the overall risk DNOs should bear under IIS due to one-off and severe weather exceptional events and whether:

- Large one-off events should be eligible for exclusion, irrespective of cause,
- Targets should be relaxed if the severe weather mechanism is made more onerous,
- Targets should be tightened given the ESQCR related expenditure on tree-trimming and network resilience.

Audits

1.87. Respondents were generally supportive of auditing by the voltage splits proposed in the initial consultation document and shown in table 25 below, although they raised concerns that smaller sample sizes could lead to more volatile results. One option could be to audit an increased number of 132kV and EHV incidents and a similar number of high voltage and low voltage incidents as now, but with more unannounced incidents so that there is not an increase in pre-audit preparation for DNOs.

1.88. One DNO has suggested the audit accuracy thresholds in table 25 which we believe would be appropriate and would welcome views on.

Table 25 - revised reporting accuracy thresholds

Voltage	Overall Accuracy	Initial stage Accuracy (smaller sample)
EHV & 132kV	97%	99%
HV	95%	97%
LV	90%	93%

1.89. We did not receive any opposition to our proposal to conduct expanded audits at each DNO on one occasion during DPCR5 (along with the streamlined audit for the other four years) and consider that given the importance of IIS and the reduction in the regulatory burden achieved through the streamlined audit approach in recent years, our approach strikes a reasonable balance for customers and DNOs.

Short interruptions

1.90. There was a strong feeling from DNOs that the increase in un-incentivised short interruptions as a result of improvements in incentivised customer interruptions was to the benefit of customers. We are broadly in agreement with this but note that as customers experience fewer long interruptions and more short interruptions, they may desire a reduction in overall interruptions. This would require the inclusion of short interruptions within IIS so that DNOs could make the relevant cost/benefit trade-offs.

1.91. We will continue to monitor customer expectations in this area and propose a work stream for DPCR5 aimed at developing more robust short interruption data to facilitate the introduction of an incentive in DPCR6 if this were required.

Voltage quality

1.92. Respondents were not supportive of changes to the voltage quality standards and given the low number of voltage complaints we are proposing to make no changes in this area.

Non-domestic customers

1.93. Non-domestic customers have expressed concerns that the current IIS does not differentiate between different classes and sizes of customers and the impact of interruptions on them. As a result DNOs may prioritise the restoration of large number of small users (e.g. households) at the expense of a small number of large users (e.g. factories). Current IIS reporting mechanisms do not require DNOs to identify whether customers interrupted are domestic or non-domestic. We intend to introduce new requirements to support this going forwards. We would welcome views on this.

1.94. Non-domestic customers have identified communication as a major element of their relationship with their DNO and we are pleased to note that DNOs do provide tailored services, such as priority lines and identified points of contact, for many of their larger customers. We invite views as to whether this practice should be offered as standard to all large customers, possibly through a sign-up mechanism.

Appendix 8 - Cost assessment methodology

1.1. This appendix sets out further details of our approach to the comparative efficiency analysis work for setting operating costs and our methodology for determining requirements for network investment.

Comparative efficiency analysis

1.2. We consider that there is continued value in benchmarking operating costs as part of this review, particularly in the light of the significant increases in cost being forecast by the DNOs. We intend to continue with comparative efficiency analysis as the core of our methodology for setting cost allowances for network operating costs, non-operational capex and total indirect costs for the DPCR5 period.

1.3. We have been discussing our approach to cost benchmarking with a number of academics as well as the DNOs and are looking to develop the range of techniques we are using in line with best practice for other regulators taking into account the availability of data. We will be using a mixture of top-down and bottom-up regressions using corrected ordinary least squares (COLS) regressions, panel data techniques and data envelope analysis (DEA). Where we consider that specific costs are less suitable for regression techniques we will be using expert review or other bottom-up analysis. We will review and assess the results of all these approaches in forming a view of efficient future costs.

1.4. There are a number of key steps in carrying out our comparative efficiency analysis and setting our forecasts for operating costs. While some of the steps are dependent on others before they can begin, others can be run concurrently.

- gathering appropriate cost and other data from the DNOs through the annual cost reporting exercise, FBPQs and other data requests as necessary,
- determining which costs should be assessed through benchmarking techniques such as regression analysis, panel data techniques and DEA and which costs should be assessed through expert review and other bottom up analysis,
- carrying out the benchmarking analysis which involves:
    - adjusting the base data to remove inconsistencies and addressing company specific factors,
    - determining appropriate cost groupings and associated drivers,
    - carrying out appropriate statistical testing or other analysis,
- carrying out expert review or other bottom-up analysis for relevant areas of costs,

- forecasting the impact of changes in activity on costs for the DPCR5 period, and
- applying 'catch-up', ongoing efficiencies and adjustments to input prices to roll forward benchmark costs into allowances.

Cost reporting

1.5. A key objective of the cost review work since 2005 has been to obtain consistently reported costs at an appropriate level of detail to allow for improved comparative efficiency analysis at DPCR5. We have made significant progress in identifying and resolving inconsistencies in the data. This provides a stronger foundation for the comparative analysis for DPCR5.

Determining the approaches to be applied for different areas of costs

1.6. Table 1 summarises the approaches we will adopt for different areas of costs.

Table 1 Approach for cost assessment

Regression analysis, panel data, DEA	Bottom-up review of costs/DNO assumptions	Expert review
Faults	Tree cutting costs	IS
I&M	Road occupation costs	Property Management
Engineering Indirects (excluding wayleaves)	Wayleaves	
Network support (excluding training)	Insurance costs	
Business support (excluding insurance)	Training costs	
	Other costs including submarine cables, island generation and unmetered substation electricity	

1.7. We are in the process of appointing consultants to carry out a review of information system (IS) and property management costs

Benchmarking based on statistical techniques

Exclusions and normalisation adjustments

1.8. We consider that it is appropriate to make adjustments to DNOs' data prior to carrying out benchmarking for the following reasons:

- to exclude elements of the costs from the regression analysis that are, or are largely, outside the control of the DNOs, and
- to address company specific factors such regional labour costs (normalisation).

1.9. During the recent cost visits to the DNOs we discussed our latest thinking on adjustments and exclusions to determine the base cost data for our regression analysis. Our latest thinking is set out in table 2.

1.10. The first column lists those costs where we consider it appropriate to undertake regression analysis, both including and excluding the adjustments, to determine whether the results are significantly affected. This should give us increased confidence in the results and help us to understand how particular factors impact on the outcomes and come to a more informed view of how they should be treated.

1.11. The second column shows the other adjustments we intend to make for the regression analysis to normalise the reported costs.

Table 2: Latest thinking - exclusions and normalisation adjustments

Possible exclusions (analysis carried out both with and without the costs)	Normalisation
Related party margins	Non-Operational Capex
Pensions	Labour Regional
Atypicals	Contractors Regional
	In-Outsourcing
	Accruals

Related Party Margins

1.12. In DPCR4 related party margins were excluded from the costs for comparative efficiency analysis using the '75 per cent rule'.[48] Related party margins were removed for any affiliated business that received less than 75% of its turnover externally.

1.13. Most DNOs consider that related party margins should be included within the comparative analysis and that any excessive margins would be removed through benchmarking. We are giving this further thought but have some concerns that this may result in additional costs to customers because of the way regression analysis is undertaken. Our concerns are somewhat mitigated by the fact that we now have three years of data and are able to identify where we think margins may be excessive.

[48] Our general policy developed as part of DPCR4 is that related party margins are removed unless the related party earns 75 per cent of turnover externally and charges are consistent with those for external customers.

1.14. We propose to run the comparative analysis work with margins included and again with them excluded using the DPCR4 rule. We will then be able to determine whether the inclusion of margins has a material impact on our results.

Pensions

1.15. We discussed the treatment of pensions for comparative analysis at a meeting with the DNOs earlier this year and at the cost visits. The DNOs hold very different views on this subject and we have identified significant issues in relation to any chosen treatment of pensions.

1.16. Some DNOs were in favour of including pensions at the current rates because this reflects the business decisions about insourcing or outsourcing that the DNOs face and best reflects the way the businesses are managed. Other DNOs were in favour of excluding pensions for practical purposes because of the difficulty of identifying all the required adjustments if they remain within the analysis; while others favoured exclusion because of the different timing and attitudes to risk of the independent actuarial valuations and pension trustees. In the Gas Distribution Price Control Review, gas distribution networks (GDNs) and related party pension costs were normalised to a standard contribution rate for the analysis.

1.17. We have identified advantages and disadvantages of each of these approaches and are of the view that no single approach is ideal at this time. We are considering running the comparative analysis work with pensions included, with pensions excluded and with a 'normalised' contribution rate for DNOs' own and related party employees.

Atypical Events (including Severe Weather)

1.18. In our annual cost reporting it is clear that DNOs have interpreted the definition of some atypical costs differently. To ensure consistency we intend to adjust the costs for some DNOs and will be undertaking further analysis over the coming months to make such adjustments.

1.19. In some cases atypical costs will have been incurred because of specific circumstances that will not recur. In such cases it may not be appropriate to use those costs to ultimately help set allowances in the future. In other cases, DNOs incur costs that are defined as atypical on an ongoing, if infrequent, basis. In such cases we need to make an allowance for an average expected level of costs in setting allowances.

1.20. We propose to undertake further analysis to identify which costs that have been reported as atypical should be included within the regression analysis.

1.21. At DPCR4 we set separate allowances for atypical storm related costs outside of the base regressions. In DPCR5 we propose to run the regressions both with and without the inclusion of severe weather events to determine the impact those costs have on the regressions and to help determine how allowances for such costs should be set.

1.22. The following table sets out possible variations of the comparative analysis dependent on which elements of costs are included or excluded.

Table 3: Possible variations of the comparative analysis

Comparative Analysis	RP Margins	Pensions	Severe Weather Events
1	Included	Included	Included
2	Included	Included	Excluded
3	Included	Own labour normalised rate	Included
4	Included	Own labour normalised rate	Excluded
5	Included	Excluded	Included
6	Included	Excluded	Excluded
7	Excluded	Included	Included
8	Excluded	Included	Excluded
9	Excluded	Own labour normalised rate	Included
10	Excluded	Own labour normalised rate	Excluded
11	Excluded	Excluded	Included
12	Excluded	Excluded	Excluded

Normalisation adjustments

1.23. We have asked the DNOs to identify appropriate normalisation adjustments accompanied by sufficient justification and estimation of the costs involved. To date there has been relatively little response, apart from EDFE providing detailed estimates of regional labour adjustments for both direct and contract labour. Where DNOs consider that such costs are material and are seeking some form of adjustment they must provide appropriate analysis as part of their February FBPQ responses.

Non-Operational Capex

1.24. We are of the view that non-operational capex costs should be redistributed across the activities which they support to negate the differences in reporting dependent on the procurement policies of the DNOs.

Labour & Contractors Regional Adjustment

1.25. We have discussed with the DNOs how we might make appropriate adjustments to take account of the different labour costs across the country.

1.26. Our current view is that we should make adjustments to costs based on the market cost of those resources where they are location specific activities. Where activities are not location specific not adjustment should be made.

In-Outsourcing

1.27. The costs reporting rules allow for costs to be reported differently, i.e. attributed to different activities, depending on whether those costs are outsourced or not. Depending on the drivers used there may be a necessity to adjust costs to take account of this difference in reporting to ensure costs are assessed on a consistent basis.

Accruals

1.28. Where we or the DNOs have reported costs that relate to a different reported year we will adjust those cost to ensure the analysis uses the correct costs for each year.

Grouping costs and determining cost drivers

Summary

1.29. We have developed the analysis from previous reviews to include bottom-up and top-down modelling. Together with the DNOs we have undertaken extensive work to understand the main cost drivers for each activity. We have then used this to guide our view of those activities that we should group for benchmarking purposes.

1.30. Table 4 shows our current view of cost groupings and appropriate cost drivers. We expect our view of the groupings and cost drivers to develop in the lead up to our methodology and initial results paper in May 2009 and further until the Initial Proposals consultation in July 2009.

Table 4: Current view of cost groupings and drivers

Cost Grouping	Driver
LV & HV Underground Faults	Fault Numbers
LV & HV Overhead Faults	Fault Numbers
Tree cutting	Based on the reopener analysis of unit costs at each voltage
Inspections and Maintenance	Further work needed on appropriate drivers
Network Policy, Network Design, Project Management System Mapping	Network Investment Activity
Engineering Management, Control Centre, Call Centre, Stores, H&S and Operational Training	Network Investment and Network Operating Costs Activity
Vehicles & Transport, HR and Non-Operational Training	Insourced Network Investment and Network Operating Costs Activity

Cost Grouping	Driver
Finance & Regulation, CEO Etc	Network Scale

1.31. As noted above we are excluding traffic management act (TMA) costs, wayleaves, unmetered electricity, submarine cable, island generation, insurance, property management and IS from the statistical benchmarking and considering them separately. Despite the efforts of both the DNOs and ourselves we have not been able to determine logical main cost drivers that explain the differences in costs for all the remaining areas. These areas are listed below:

- EHV and 132kV Faults,
- LV and HV plant Faults,
- Non Quality of Service Faults,
- Non-operational capex.

1.32. The next section of this appendix addresses each of the areas listed to explain our current view of why we have not included them within the bottom-up comparative efficiency review groupings to date. We then set out our current view of the appropriate cost drivers for each of the groupings for the bottom-up modelling as listed in table 4.

Costs currently excluded from the groupings

EHV & 132kV Faults

1.33. The average spend on typical faults for EHV and 132kV assets over the three years 2005-06 to 2007-08 is just £18.6m across all the DNOs. The three year average on a per DNO basis was between £0.4m and £2.8m. This broad difference in the results reported suggests very different experiences of these faults and/or differences in reporting.

1.34. The circumstances of any fault at those voltages can have a significant impact on the cost of faults that make a cost per fault analysis unsuitable. Three years of data is not considered enough to ameliorate the result of specific high cost events. For these reasons we do not consider EHV and 132kV faults costs to be suitable for regression analysis.

1.35. We will continue to consider the appropriate means to determine efficient levels of spend on these assets in the coming months.

LV and HV Plant Faults

1.36. The average spend on typical faults for LV and HV plant over the two years 2006-07 and 2007-08 is just £10.6m across all the DNOs. The three year average cost on a per DNO basis was between £0m and £2m. The small level of total costs and the difference in reported values suggest these activities are inappropriate for comparative analysis because of the susceptibility to allocation errors and the materiality threshold in reporting.

1.37. Our current view is that these costs should not be included in the regression analysis with other activity costs because the drivers of these costs are different. We will continue to consider how we should treat these costs for determining efficient cost levels and allowances for DPCR5.

Non-Quality of Service Faults

1.38. The average spend on Non-Quality of Service faults over the three years 2005-06 to 2007-08 was £41.8m across all the DNOs. The three year average spend on a per DNO basis was between £0m and £7.8m.

1.39. As part of the high level forecast business plan questionnaire (HLFBPQ) we asked DNOs to provide us with a further breakdown of those costs to allow us to undertake further analysis with the intention of determining where there are inconsistencies in reporting. We will carry out additional analysis using this data and report the results in the Methodology and Initial Results paper which we will publish in May 2009.

Non-Operational Capex

1.40. Non-Operational Capex is made up of a number of distinct cost areas including vehicles, IT, small tools & equipment and property. By its nature non-operational capex spend tends to be 'lumpy' and on an annual basis is not appropriate for comparative analysis.

1.41. We have already noted above our intention to appoint consultants to assess property management costs and this will include property related non-operational capex. We will also be appointing specialist consultants to assess IS costs.

1.42. We have identified two potential approaches to obtaining the data we need for comparative analysis purposes including:

- using statutory non-operational depreciation, or
- asking DNOs to identify their 'smoothed' spend on non-operational capital items for each of the three years.

1.43. There are issues with both of the approaches identified and both would require an additional data request and review of the outcome of the work. We are seeking views on which approach is the most appropriate to identify 'normalised' non-operational capex spend for the years 2005-06 to 2007-08.

Activity groupings and cost drivers

1.44. We have already discussed the possible groupings of costs with the DNOs during the cost reporting visits in September and October this year and considered the comments we received at that time. This report provides the opportunity for the DNOs and other interested parties to comment on our current view as amended after those discussions.

1.45. We have only tried to identify the prime driver of particular costs rather than attempting to identify every driver for each particular aspect of an activity, quantified or otherwise. We are of the view that this is appropriate for comparative efficiency purposes on a bottom-up and top-down basis

LV and HV Underground Faults

1.46. Our current thinking is that it is most appropriate to undertake benchmarking of HV and LV underground faults together using the number of faults as the main cost driver. Both the DNOs and ourselves have identified some issues with the quality of cost reporting of faults for individual asset categories and we therefore have concerns about undertaking the analysis at a greater level of disaggregation. One of the issues relates to reporting services costs separately from LV mains. Our concerns relate to whether DNOs are reporting service joints consistently.

1.47. DNOs have identified that in some cases their reporting systems are inadequate to report pressure assisted underground cable faults from non-pressure assisted cable faults. In such cases those DNOs have used management judgement to attribute costs across those two categories. We have made it clear that we expect DNOs to augment their systems but to date this has not been done in some cases.

1.48. The total expenditure on faults in 2007-08 as reported in the RRP was £305m. Of this LV and HV underground faults accounted for £187m (61 per cent).

LV and HV Overhead Faults

1.49. Total expenditure for LV and HV overhead faults in 2007-08 was £39.3m, 13 per cent of the total. We consider that these costs should be grouped together for the comparative analysis with the number of faults as the main cost driver.

Network Policy, Network Design, Project Management, System Mapping

1.50. Our current view is that the prime driver of these costs is the level of network investment activity. There are a number of means of determining network investment activity, the easiest to determine being the costs reported in the RRP. However, we are of the view that using costs directly as the driver would not be appropriate.

1.51. We intend to build a network investment driver based on the level of activity in terms of the assets added to the network each year multiplied by an adjusted unit cost which gives the relative weightings of those assets. We will need to adjust those unit costs to ensure the driver is not skewed toward assets that incur the highest costs (e.g. primary transformers). This development will be dependent on discussions with the DNOs to develop those adjusted unit cost figures.

Engineering Management, Control Centre, Call Centre, Stores, Health and Safety and Operational Training

1.52. Our current view is that the prime driver of these costs is the level of network investment together with the level of network operating costs activity. We will be developing a further measure of activity for these costs over the coming months with the co-operation of the DNOs.

Vehicles & Transport, HR & Non-Operational Training

1.53. Our current view is that these costs are primarily driven by the network investment and network operating cost activity undertaken by the DNO in-house and its related parties. Where activities are undertaken by contractors those costs will, in most cases, be reported under the direct activities to which they relate rather than under indirect costs.

Finance & regulation and CEO etc

1.54. These costs have a fixed element plus a variable element dependent on the size of the business. At DPCR4 we used a 'network scale' driver (combining network length, customer numbers and units delivered) as a proxy for the size of the business and there are a few alternative models now available to us. We will continue to develop our understanding of these network scale variables to determine the most appropriate one to use for these costs in DPCR5.

Inspections and maintenance

1.55. The average spend on inspections and maintenance over the 2005-06 to 2007-08 period is £102.7m across all the DNOs. These costs exclude items such as unmetered substation electricity, emergency back-up arrangements and dismantlement. The figures reported are consistent for the whole of the industry over that period.

1.56. Despite the overall consistency in costs across the industry over time there does not seem to be a similar level of consistency across the assets over the years or across DNOs for any specific assets.

1.57. The majority of the inspections and maintenance spend (59 per cent) is on plant (switchgear, transformers & substations) but this percentage varies between 46 per cent and 82 per cent across different DNOs. Ofgem and the DNOs have been working on developing appropriate drivers for inspections and maintenance costs over the past two years. We will be continuing this work over the period up to initial proposals.

Tree cutting

1.58. The key tree cutting analysis has been undertaken on a unit cost basis as a part of the DPCR4 reopener. We expect the results of that analysis to identify appropriate allowances for DPCR5 and intend to use the comparative efficiency analysis work to confirm that the unit cost work is appropriate.

Benchmarking techniques

1.59. We have been discussing our approach to the cost benchmarking with a number of academics as well as the DNOs and are looking to develop the range of techniques we are using in line with best practice for other regulators taking into account the availability of data. To achieve this we will use a number of techniques including:

- Panel/Time Series Data
- Bottom-Up and Top-Down Analysis.
- International Data
- Ordinary Least Squares (OLS)
- Data Envelope Analysis (DEA)

1.60. Together these approaches will allow Ofgem to assess the relative efficiency of the DNOs on a robust basis, because they offer different strengths and provide sense checks against one another. In particular, the bottom up benchmarking will allow Ofgem to explore the insights offered by the more detailed data that have been generated since the last Price Control through the RRP. Meanwhile, the top down benchmarking will allow Ofgem to capture trade-offs between the different activities carried out by the DNOs as well as making international comparisons possible. We are committed to transparency and using reasonable judgements in how we combine these techniques. We are aware that the empirical results of the different benchmarking techniques must be comparable, or, where there are significant differences in the results they must be understood before the benchmarking results are used in the overall assessment of costs.

Panel/time series data

1.61. We have collected RRP data from 2004-05 and have just completed the review of the 2007-08 data. Although the data for 2004-05 is reported on the same basis as the other years it was the first full year of developing the RRP and the quality of data is considered to be not of sufficient standard to be included in the analysis. We therefore have three years of data for the fourteen DNOs providing us with forty-two data points for our analysis. By the Initial Proposals document next year we will have an additional year's data.

Bottom-up *a*nalysis

1.62. We intend to use OLS, pooled regression and panel data techniques for bottom-up analysis not only to produce comparative efficiency results but also to develop our understanding of the cost drivers within the DNO businesses and thereby to develop relevant cost drivers for the activity groupings. The use of bottom-up analysis has already benefited our understanding of cost drivers and identified anomalies in the reported data. We believe this has helped to improve the quality of the reported data in the annual RRPs.

Top-down analysis

1.63. In addition to the bottom-up analysis we will undertake top-down analysis of the data using OLS and Corrected Ordinary Least Squares (COLS), Data Envelope Analysis (DEA) and panel data approaches. We will use a combination of these techniques to determine appropriate efficiency benchmarks.

International data

1.64. For the top down benchmarking, we intend to gather data about international comparators in order to improve the breath of the efficiency analysis as well as the sophistication of the measurement techniques. The Office of Rail Regulation took this approach in their recent determination for Network Rail.[49] It also provides a stronger match to the analytical approach in the academic literature and latest consultancy reports.[50] Drawing on information about electricity DNOs from other countries, and extending the number of DNOs for comparison, might make it possible to use more sophisticated statistical and non-parametric techniques, which will strengthen the rigour of the analysis.

1.65. So far, we have focused on gathering data about DNOs in the North East of the United States (US). The reasons for this focus are that data is relatively easily available from the US regulators' websites and the climate of the North East US provides the best match to that of the UK.

1.66. We recognise the inherent difficulties in comparing UK data with that from other countries, not least the labour rate differences and using exchange rates to compare costs in different currencies. However, preliminary results indicate that the North Eastern US DNOs are reasonable comparators to UK DNOs.

1.67. We intend to extend our sample to include European DNOs. Initially, we will concentrate on gathering data about Scandinavian DNOs because the regulatory authorities in these countries have already undertaken benchmarking analysis at a national and international level. To the extent we can draw on previous work, it is likely to strengthen our analysis and minimise our independent effort.

1.68. We are likely to carry out top down international benchmarking on both operational expenditure and total expenditure. Data availability is likely to mean that our cost drivers will consist of customer numbers, network length and units distributed. We will carry out regression analysis (including both COLS and stochastic frontier analysis (SFA)) and DEA. We will investigate whether we have adequate data to carry out meaningful panel analysis, which would exploit that we have data about the same DNOs over time to draw more robust conclusions about their relative efficiency.

[49] ORR 2008, Periodic Review 2008: Determination of Network Rail's outputs and funding for 2009-14 and ITS 2008, International benchmarking of Network Rail's maintenance and renewal costs: an econometric study based on the LICB dataset.
[50] London Economics 1999, Efficiency and benchmarking study of NSW distribution businesses and Forsund, F. and Edvardsen, D. 2001, International Benchmarking of Electricity Distribution Utilities.

Areas for expert review and bottom-up quantitative and qualitative analysis

1.69. The section below sets out our latest thinking on other areas of costs which we consider are more appropriately assessed through expert review or other bottom-up analysis, but are less suitable for regression work. In some cases it may be appropriate to include the costs in the top-down analysis.

Property management and related non-operational capex

1.70. Since privatisation DNOs have diversified their resourcing of non-operational buildings. DNOs retain some buildings owned at the time of privatisation but also utilise other accommodation and incur rental charges to external bodies for such properties. DNOs also differ in their reporting for property costs because service charges are in some cases included within the rental charges for properties and in other cases they are not.

1.71. We will be appointing specialist consultants in this area to review DNO costs and advise us how best to set allowances for DPCR5. As part of this work, the consultants will be asked to prepare a detailed inventory of the DNOs' property portfolio as it evolved from privatisation in 1989 to the present day. This will provide us with more comprehensive information on the value and timing of property purchases, transferrals and disposals, including details of any leasehold arrangements. The consultants will undertake an assessment of property costs for the period 2005-06 to 2008-09, particularly work space deployment, facilities management and the costs of work space such as rents and costs per full-time equivalent (FTEs). The consultants will also undertake an assessment of the likely workspace requirements for the DPCR5 period and together we expect this work to provide a projection of efficient property costs for each DNO through to 2015.

IT & Telecoms and related non-operational capex

1.72. The IT and Telecoms activity and related Non-Operational Capex is subject to significant differences in approach between DNOs. Not only are IT & Telecoms costs incurred to assist the business as a whole, specific hardware and software can be developed and implemented to make other specific activities more efficient.

1.73. In the past three years we have collected data on IT & Telecoms on a disaggregated level to assist our understanding. Our intention is to employ consultants to assist in the DPCR5 analysis of IT & Telecoms. We will be collecting additional information in a specific data request to assist those consultants with their work.

1.74. The consultants will be required to review the overall systems framework within the DNOs and the costs of key applications and infrastructure. They will also need to carry out comparisons across DNOs and any relevant external benchmarks.

Insurance premia and insurance management

1.75. The scope and extent of insurance is a specialist area with very different practices across the DNOs. Insurance can be viewed as a means to protect the financial wellbeing of a DNO in the case of unexpected loss by means of a regular payment. The impact on the costs reported in the RRP should be that the costs are still reported but that any retrieval from an insurance policy is shown as a cost recovery.

1.76. Our current thinking that the specialist nature of these costs and the degree of difference between the DNOs means that this should be looked at separately from the main comparative analysis. We therefore propose to exclude these from the cost regressions and undertake a separate assessment based on a bottom-up approach.

Apprentice training

1.77. We collect data from each DNO on the number of apprentices undertaking 'classroom based' training and the cost of those apprentices. The evidence from the RRPs shows that not only are there differences in the throughput of apprentices but that some DNOs currently do not train apprentices.

1.78. All DNOs are forecasting increases in direct costs in the DPCR5 period and across the industry there is recognition that the ageing workforce and major increases in capex work is leading to significant increases in training needs. Energy Utility Skills together with the DNOs have presented evidence of training apprentice and training requirements for all DNOs.

1.79. Although the amount of training undertaken is within the control of the DNO we are of the view that it would be unfair to include these costs in the main benchmarking analysis because it would show those DNOs that are already investing in training to be relatively inefficient. The same argument could be extended to apprentices doing 'in the field' training but this would be much more difficult to quantify.

1.80. We propose to exclude the costs of apprentices while undertaking 'classroom based' training from the regression analysis and undertake a separate assessment of the training needs data provided by the DNOs to determine appropriate levels of training costs in the DPCR5 period.

Road occupation charges

1.81. The fees payable for Road Occupation Charges are, to some degree, at the discretion of the various highways authorities and therefore partially outside the control of the DNOs. Specific road occupation charges in the form of a congestion charge are payable in Central London and there is an expectation that similar schemes may be introduced in other metropolitan areas in future years, although the timing is unknown.

1.82. We propose to undertake separate analysis internally to assess the appropriate level of costs for each DNO.

Overstay fines

1.83. The charging of 'overstay fines' are also, to some extent, at the discretion of the highways authorities. The majority of overstay fines are incurred as a result of load and non-Load related work and will therefore be included within the scope of the modelling for those costs. However, some costs have been reported that relate to Network Operating Cost activities.

1.84. We propose to undertake separate analysis internally to assess the appropriate level of costs for each DNO.

Other Traffic Management Act (TMA) costs

1.85. There is still uncertainty as to the timing and extent of permit schemes and penalties under the Traffic Management Act. As a result some DNOs have begun to invest early in IT systems and others have not. To include any such investment would appear to make those DNOs that have invested appear less efficient.

1.86. We propose to exclude any set-up costs for TMA from the regression analysis. We will continue to monitor costs and forecasts over the next year as TMA begins to be implemented across the DNO areas and intend to carry out bottom-up analysis to determine allowances for traffic management as a whole.

Wayleaves

1.87. Easement (Servitude) costs are incurred within the Load and Non-Load Activities and are therefore to be considered as part of the modelling of those costs. Wayleave costs are reported in the RRP under the Engineering Management & Clerical support Activity.

1.88. The value of wayleave costs incurred is impacted by a number of factors including the number of 'agents' working to maximise the income for landowners from network operators. There is some evidence that the wayleave payments are usually on a schedule of rates accepted across the country but we do not have any information about the amount of network for which a wayleave could be payable but for which the DNO incurs no such costs. Further, there is an opportunity for DNOs to convert wayleaves into easements but we do not have any evidence that this practice is happening more or less at any of the DNOs.

1.89. The total reported costs for wayleaves across the DNOs in 2007-08 was £33m. We will undertake further work to understand the reasons behind the level of wayleave costs incurred by the DNOs over the next year but propose to exclude wayleave costs from our general benchmarking analysis. We will make a separate assessment of the appropriate level of wayleave costs for each DNO.

Unmetered electricity used at substations

1.90. In the RRP some DNOs report charges for electricity used at substations while for other DNOs the costs are incurred via the losses incentive under the DPCR4 rules. This different treatment makes comparative analysis of unmetered electricity cost across the DNOs impractical. Further work on unmetered electricity at substations is being undertaken by our policy team. Our treatment of these costs for allowance setting purposes will be driven by that work.

Submarine cables

1.91. Some DNOs have submarine cables on their networks while others do not. The costs of repairing these assets can be significant and would unfairly impact the comparative analysis. We will determine an appropriate approach for dealing with submarine cable costs over the following months.

Island generation

1.92. These costs relate to maintaining standby generation in the event that a single feed line fails. Only a few of the DNOs incur such costs. We will determine an appropriate approach for dealing with those costs over the following months.

Allowance setting

1.93. We use the results of the comparative efficiency analysis as the starting point for determining a set of opex forecasts for each of the DNOs. To achieve this we will:

- review and combine the results of the regression analysis,
- reverse some of the normalisation adjustments (e.g. labour adjustment)
- exclude any residual pensions costs within the analysis,
- add back the results of the quantitative and qualitative reviews undertaken by ourselves or our consultants,
- determine the potential and projected impact on costs of our expectations of changes in activity in the DPCR5 period, and
- apply 'catch-up', ongoing efficiencies and adjustments in real prices to roll forward benchmark costs into allowances.

Assessment of network investment

Load-related investment

1.94. Load-related investment covers all expenditure on the networks to increase network capacity (including fault level capacity) in response to changes in demand or generation. In addition for DPCR5 we are including expenditure on non-rechargeable diversions, easements, conversion of wayleaves to easements and injurious affection[51] payments in the load related investment assessment as these costs are similar in nature to investment in capacity as they are usually triggered by user requirements and the DNO has limited control over them. Previously this expenditure was categorised as non-load related.

1.95. In DPCR4 load related investment was assessed through both high level top down modelling (benchmarked across the DNOs) and a review of specific schemes and consideration of known load changes. The top-down modelling used units distributed and customer numbers as drivers for gross load related expenditure, including expenditure on new connections and reinforcement but excluding expenditure on generation connections. A 50 per cent weighting was applied to each driver. The model scaled historical expenditure per new customer and per additional unit using the Modern Equivalent Asset Value (MEAV) per customer and per additional unit for each DNO. This was then benchmarked across DNOs. The benchmarked cost per new customer and cost per additional unit was then used to project expenditure for the DPCR4 period using projections of customer numbers and units distributed.

1.96. In the context of a levelling off of units distributed and an economic downturn causing significant uncertainty in forecasts of units distributed and customer numbers we are looking at alternative methods of load-related modelling for DPCR5. In particular units distributed and new customers no longer appear to be the most suitable drivers of load related expenditure and the modelling applied at DPCR4 cannot account for the levels of expenditure being forecast in the August FBPQs. Instead DNOs are citing high levels of load growth in localised areas or 'hotspots' as the main driver of load related expenditure.

1.97. To take account of these issues we are considering an alternative approach to load related modelling using different techniques for the customer specific and general reinforcement building blocks. We will also consider modelling LV and HV general reinforcement requirements differently to EHV and 132kV general reinforcement requirements.

1.98. Required network investment which can be directly attributed to identifiable new connections (customer specific demand investment), is clearly very dependent on the volume of new connections. With current uncertainties around future volumes it may be appropriate to link the associated network expenditure allowances directly to volumes using an investment driver. Allowed network investment expenditure will then rely on developing a cost per connection based on historical levels of expenditure. We are also considering the scope for benchmarking these costs, taking into consideration regional and network specific factors.

1.99. For general reinforcement costs at LV and HV we are considering the use of top down modelling techniques similar to those employed at DPCR4 but updated for more appropriate drivers.

[51] Injurious affection is where compensation is recoverable not only for the value of land taken, but for consequential damage to other property.

1.100. For EHV and 132kV general reinforcement we are developing a model based on measures of growth on individual, more highly loaded substations as drivers. As part of the Regulatory Reporting Pack (RRP) the DNOs already report data relating to substations loaded to more than 80 per cent of firm capacity on an annual basis. We have developed the February FBPQ to include details of these substations and collect additional information about the historical and forecast loading of the substations. We are also collecting information on the additional MVA of firm capacity that the DNOs forecast during the DPCR5 period. This information will allow assessment and benchmarking of load related expenditure (LRE) based on a more disaggregated view of demand increases.

1.101. In addition where possible we will look to link the modelling of general reinforcement to the development of load related output measures.

1.102. We are giving consideration to treating very large, more uncertain EHV and 132kV general reinforcement schemes separately. Details of these schemes will be separately captured in the February FBPQ. We are looking at the potential to identify triggers for additional expenditure allowances for these schemes and will be working with our consultants to assess these schemes and develop appropriate triggers.

Non-load related - asset replacement

1.103. In DPCR4 one of the tools used to assess asset replacement volume and expenditure was top down asset replacement modelling. Asset replacement modelling uses assumptions of average asset lives (average lives at which assets are replaced based on condition information or failure), the distribution around those average lives and the DNOs' asset age profiles to forecast a volume of asset replacement required due to condition. Outputs from the model were adjusted for factors which the modelling did not take into account by benchmarking them against the DNOs' forecasts. The forecasts were also used to inform discussions with the DNOs.

1.104. The DNOs submit asset age profiles in the RRP. These are their best view of the years of installation for all assets on their network. The DNOs also submit their views on average asset lives and their distribution in the RRP.

1.105. In DPCR5 we will use asset replacement modelling again to inform allowances, together with the DNOs' own forecasts. The asset replacement model and the mathematics behind it are well understood by the industry. The key to producing more accurate forecasts of asset replacement volumes is not in the workings of the model but in the input assumptions used. In particular, the assumptions used for average asset life and distribution have a large influence on the output of the model and will be the primary focus of detailed analysis in DPCR5.

1.106. We are currently considering a range of approaches to assessing asset lives. These include:

- Adjusting asset life assumptions to match historical levels of asset replacement (both at an individual DNO level and at a total industry level),
- Analysing asset lives implied by DNO volume forecasts presented in the FBPQ (again at a DNO and industry level),
- Analysing the asset lives implied by forecast that have been developed through the use of health indices, and
- Benchmarking of DNO asset lives, comparison with previous price controls (transmission and distribution) and international comparisons.

1.107. We will consider separate modelling of overhead lines taking refurbishment cycles into account.

1.108. We recognise that asset replacement modelling is just a tool for forecasting volumes without taking full account of actual known condition of individual assets. Any output of the model will be benchmarked at both the volume and total costs level to provide an Ofgem 'modelled view'. The Ofgem final view will also be the subject to an expert review and a level of judgement which will be informed by discussion with each DNO.

1.109. The DNOs are currently in the process of building up databases of Health Indices (HI) to capture the condition of individual assets. Where DNOs' forecasts are materially higher than the volumes output by the model we will look for the DNOs to provide evidence for increased replacement requirements such as detailed condition information such as health indices.

Other non-load related

1.110. For other areas of investment, proportional to the level of investment, a combination of top down modelling and benchmarking and bottom up assessment will be used. It may also be appropriate to use a general adjustment factor based on the outcome of the assessment of load related investment, asset replacement modelling and our unit costs assessment.

HILP (High Impact Low Probability events)

1.111. The DNOs have forecast considerable expenditure on mitigation of HILP events. We seek views on the how the appropriate levels of this expenditure should be assessed. As part of their stakeholder engagement the DNOs have encountered varying views on whether the costs of HILP should be met by the local stakeholders or by consumers generally. We would welcome views on how the costs relating to HILP event mitigation should be funded.

Unit costs

1.112. The assessment of unit costs will be carried out with the help of our consultants as a separate work stream. This analysis will consider use of benchmarking of DNO unit costs, international and industry comparisons and assessment of actual tendered contract costs.

1.113. The benchmark unit costs will be used for both the load related capex (LRE) and non-load related capex (NLRE) modelling. For the LRE modelling the units costs will be used to calculated a modern equivalent asset value (MEAV) of the network to be used in the benchmarking of incremental LRE expenditure. For NLRE the units cost will be multiplied by the volume of asset replacement to calculate a total modelled cost for asset replacement.

1.114. The benchmarking of DNOs' unit costs will include both a review of the unit costs provided by the DNO in the FBPQ and analysis of the implied historical and forecast unit costs. The implied unit costs are calculated by taking actual or forecast expenditure on a given asset and dividing by the actual or forecast volume of replacement.

1.115. In the August FBPQ the DNOs were requested to submit unit costs on a direct cost basis. The range of costs for similar items of equipment was very large, typically two to one for many categories of assets but considerably more in some categories. Other than errors and misinterpretations, there are three possible reasons for the degree of variability:

- the price paid by the DNO for the equipment,
- whether the equipment is installed by direct labour or a contractor, and
- the scope of the work being undertaken.

1.116. The first reason may be largely discounted since the degree of variability is so large. The second reason could be significant since the unit cost table only includes direct costs and there would be a difference between direct costs based on internal labour and those that include fully absorbed contractors' costs. Therefore to avoid this issue we will look to benchmark unit costs including a level of overheads to account for the different allocation of costs between direct labour and contractors.

1.117. The third reason may be more significant. A DNO may carry out more extensive work than another in replacing an item of equipment. For instance, one DNO could replace an outdoor breaker with a similar modern equipment and leave all existing secondary equipment, multi-core cabling, protection and control equipment etc in place if considered serviceable. Another DNO may have a policy of replacing the complete switchgear bay including civil refurbishment or indeed replacement on a new site where new substation infrastructure has to be established. Each of these approaches may be justified under different circumstances.

1.118. A DNO may also submit unit rates for equipment replacement based on a like-for-like replacement of the primary plant but cost with secondary equipment replacement and indeed civil refurbishment separately. The company may possibly have separate work programmes covering the secondary equipment or civil work.

1.119. To assure consistency in this area we will undertake a survey of all DNOs to understand their assumptions with regards to the scope of work and the level of secondary equipment and civil costs included in their unit costs. Based on the responses to the survey we will issue further guidance in the New Year for completion of the February 2009 FBPQ unit cost tables.

Appendix 9 - Information Quality Incentive

Summary

This appendix sets out further details of our current thinking on the Information Quality Incentive.

Information quality incentives

Background

1.1. In recent price controls, including DPCR4 and GDPCR, we introduced a number of refinements to the RPI-X framework to address issues of variations in the strength of incentives throughout the price control period and risks associated with companies earning high returns through submitting high capex forecasts and then significantly underspending these forecasts.

1.2. The Information Quality Incentive (IQI) places more weight on DNOs' forecasts whilst encouraging them to forecast expenditure at more realistic levels. The IQI matrix for DPCR4 is set out below.

Table 1 - Electricity distribution sliding scale matrix

DNO:PB Power Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0.200%	0.168%	0.130%	0.090%	0.046%	-0.004%	-0.062%	-0.124%	-0.192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

1.3. The DPCR4 IQI matrix takes the form of two incentives. Firstly, DNOs are allowed to earn an additional income on their RAV based on how close their forecast is to our baseline (in DPCR4 this was termed the 'PB Power view'). The second part of the incentive sets the incentive rate for future efficiency savings based again on how close the DNO's forecast is to our baseline. Under the incentive a DNO with an inflated capex forecast is able to keep a lower percentage of any capex underspend than a DNO with a more accurate forecast.

1.4. DNOs earn the highest income by accurately forecasting their intended capex spend (this is highlighted in blue). For example in table 1, suppose the PB Power baseline is £100m. If the DNO expects to spend 100 per cent of the PB Power forecast it will earn an income of £4.5m by not inflating its forecast. This is calculated as (£105m-£100m) x 40 per cent + £2.5m. In comparison if it inflated its bid to 140 per cent of the PB Power forecast it would only earn an income of £0.6m as it loses out on both the additional income incentive and the efficiency incentive.

1.5. We consider that the IQI was beneficial in terms of encouraging both EDFE and SP to submit revised forecasts at DPCR4, reducing capex by approximately £200m. Some DNOs are also forecasting to out-turn very close to their DPCR4 allowances. However, we have concerns that some of the other DNO groups who submitted relatively high forecasts at DPCR4 have spent significantly less that their allowances to date and may out-turn significantly below their allowances by the end of the period.

Responses to the initial consultation

1.6. Responses to our consultation documents and other papers have highlighted two main issues with the IQI mechanism:

- It assumes risk neutrality by management and shareholders. In practice management may be risk averse and looking to protect themselves against increases in costs. Under the DPCR4 IQI mechanism a DNO can obtain relatively cheap insurance by submitting a slightly higher forecast. For example, assume that the Ofgem baseline for capex is £100 million in table 1. The DNO considers that it needs £110 million. If it moves its forecast one column to the right it obtains insurance for higher costs through its allowance increasing by £1.25 million. Its overall return under the IQI is only reduced by £0.1 million.
- Giving companies complete freedom to reforecast through successive FBPQs may undermine the IQI incentives. A DNO may submit a high forecast at an early stage to influence Ofgem's baselines and then submit lower forecasts to benefit from higher cost incentive rates and cash rewards under the scheme.

1.7. A number of suggested changes to the IQI matrices have been put forward to address these issues which have received mixed views across the industry. CE and Frontier Economics have suggested that risk averse managers need a greater reward in order to accept stronger incentives where overspends are possible. They suggested that we could revise the IQI matrix to make accurate forecasts relatively more rewarding to address risk-aversion. This may involve introducing some asymmetry into the scheme between under-spending and over-spending to provide greater protection against the risk of cost over-runs.

1.8. Centrica has suggested that under spending currently receives too much reward relative to an accurate forecast. It suggests that DNOs could be rewarded if their initial business plan is within a certain proportion of the Ofgem baseline. It also indicates that companies that have under spent by more than a certain percentage should be subject to much more intrusive scrutiny of their business plans for DPCR5.

1.9. EDFE and NERA note that the IQI was set up to encourage more accurate forecasting of capex, not lower forecasts. The IQI does not offer rewards for deliberately over-forecasting capex with the intention of undercutting the forecast. They suggest that underspending does not provide any evidence of deliberate over-forecasting.

1.10. Both CE and Centrica have also argued that there should be some limit on DNOs' freedom to rebid along the lines of those adopted by Ofwat. Submissions should be consistent and wholesale changes to forecasts at the final stage should not be allowed.

1.11. NERA suggest that the Ofwat rules do not add anything new to the Ofgem process.

1.12. CN focus more on the IQI as a mechanism for addressing uncertainty. They argue that it allows a DNO to choose the level of risk they wish to take on during the price control period. They can choose a higher forecast which gives them weaker incentives but greater protection against a rise in costs. CN argue that the IQI could be revised to provide greater protection against uncertainty as an alternative to other measures such as cost pass-through, indexation or greater use of cost drivers. They suggest that there should be lower sharing factors around the allowance where a higher degree of uncertainty exists and stronger sharing factors for larger variations from allowances. In addition where there are very high levels of unpredictability, such as for input prices, it may be appropriate to include some triggers beyond which indexation applies.

1.13. Both Centrica and SSE have raised issues with extending the existing IQI mechanism to opex. Centrica considers that there is little case for extending the mechanism until it has been improved. SSE is concerned that expanding the IQI to include certain operating costs could lead to the development of a total cost model. They note that this would have significant implications for the price control, potentially undermining the DNOs' incentive to invest and out-perform. SSE highlights that in DPCR4 opex allowances were determined using historical regression analysis and a benchmarked approach. It does not believe that this methodology is compatible with an incentive to drive accurate forecasts. It considers that the IQI should focus on elements of load-related and non-load related capex and if it is extended to opex, this should be as part of a separate IQI.

Further thinking

1.14. We consider that there may be merit in revising the IQI to deal with issues of risk aversion and the risk of overspending. For example, for companies which have submitted reasonable forecasts we could maintain strong incentive rates closer to the forecasts and include less powerful incentive rates (sharing factors) where the actual spend is further away. This would provide protection against large cost over-runs. We consider that such an approach should be symmetrical and provide protection for both DNOs and customers. Alternatively if further protection is only given for overspending this may have consequences for the cost of capital or the basis on which we set our baselines.

1.15. An example of such a revised IQI matrix based on work carried out by Frontier Economics is set out in table 2 below.

Table 2 - Example of an IQI mechanism to address issues of risk aversion

DNO:Ofgem ratio	100	105	110	115	120	125	130	135	140
Actual expenditure (% Ofgem view)	Rewards								
70	16.51	15.26	13.91	12.76	11.81	11.06	10.51	6.86	4.51
75	14.86	13.81	12.56	11.41	10.46	9.71	9.16	5.81	3.61
80	13.11	12.26	11.21	10.06	9.11	8.36	7.81	4.76	2.71
85	11.26	10.61	9.76	8.71	7.76	7.01	6.46	3.71	1.81
90	9.31	8.86	8.21	7.36	6.41	5.66	5.11	2.66	0.91
95	7.26	7.01	6.56	5.91	5.06	4.31	3.76	1.61	0.01
100	5.26	5.06	4.81	4.36	3.71	2.96	2.41	0.56	-0.89
105	3.21	3.26	3.01	2.71	2.26	1.61	1.06	-0.49	-1.79
110	1.26	1.31	1.36	1.06	0.71	0.26	-0.29	-1.54	-2.69
115	-0.59	-0.54	-0.49	-0.44	-0.79	-1.19	-1.64	-2.59	-3.59
120	-2.34	-2.29	-2.24	-2.19	-2.14	-2.54	-2.99	-3.64	-4.49
125	-3.99	-3.94	-3.89	-3.84	-3.79	-3.74	-4.19	-4.69	-5.39
130	-5.54	-5.49	-5.44	-5.39	-5.34	-5.29	-5.24	-5.74	-6.29
135	-6.99	-6.94	-6.89	-6.84	-6.79	-6.74	-6.69	-6.64	-7.19
140	-8.34	-8.29	-8.24	-8.19	-8.14	-8.09	-8.04	-7.99	-7.94

DNO:Ofgem view ratio	100	105	110	115	120	125	130	135	140
Incremental capex (% Ofgem view)	Marginal incentive rate (%)								
70-75	0.33	0.29	0.27	0.27	0.27	0.27	0.27	0.21	0.18
75-80	0.35	0.31	0.27	0.27	0.27	0.27	0.27	0.21	0.18
80-85	0.37	0.33	0.29	0.27	0.27	0.27	0.27	0.21	0.18
85-90	0.39	0.35	0.31	0.27	0.27	0.27	0.27	0.21	0.18
90-95	0.41	0.37	0.33	0.29	0.27	0.27	0.27	0.21	0.18
95-100	0.40	0.39	0.35	0.31	0.27	0.27	0.27	0.21	0.18
100-105	0.41	0.36	0.36	0.33	0.29	0.27	0.27	0.21	0.18
105-110	0.39	0.39	0.33	0.33	0.31	0.27	0.27	0.21	0.18
110-115	0.37	0.37	0.37	0.30	0.30	0.29	0.27	0.21	0.18
115-120	0.35	0.35	0.35	0.35	0.27	0.27	0.27	0.21	0.18
120-125	0.33	0.33	0.33	0.33	0.33	0.24	0.24	0.21	0.18
125-130	0.31	0.31	0.31	0.31	0.31	0.31	0.21	0.21	0.18
130-135	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.18	0.18
135-140	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.15

1.16. We are also giving further consideration to the alternative of 'deadbands' or setting weaker incentives around the allowances as part of the IQI. This may address concerns that the companies' that forecast closest to our view stand to bear the highest percentage of any overspend. However, we are concerned that this may reduce incentives to manage costs if DNOs are operating close to the allowance.

1.17. Our work to date has shown that it is difficult to preserve the incentive compatibility of the mechanism (i.e. to maintain the result that the best outcome for a DNO is to forecast in line with actual spending) at the same time as applying deadbands. We would not introduce such an approach if there is not a way of keeping incentive compatibility.

1.18. The detailed parameters of the IQI will depend on a number of factors. If we adopt a RAV additions approach that entails capitalising a fixed percentage of all cost types, then we already have an effective efficiency incentive, and the interaction of this with the results of the IQI need consideration. For example if

78 per cent of all costs were capitalised, then unless we specifically introduced a rolling opex incentive, DNOs would bear 22 per cent of any overspend even before application of the efficiency incentive resulting from the IQI.

1.19. In the Networks chapter we noted that there are currently imbalances between the opex and capex incentives and that we are considering a number of options for equalising incentives. If we adopt the same capitalisation rules for network costs and indirect costs or certain subset of these costs it would also be appropriate to adopt the same approach for the IQI. For example, if we are looking to have the same cost incentives for faults and I&M as for load-related capex and asset replacement it would make sense for all these costs to be included in the IQI. Comparative analysis of DNOs' historical costs is one of the core elements in developing our forecasts of operating costs, but we also give consideration to DNOs' forecasts.

1.20. We do consider that there are benefits in applying rules for re-forecasting along the rules proposed by Ofwat and have already announced this in our November 2008 letter.

1.21. We are still considering the appropriate scope of the IQI and which building blocks it will apply to. However, we will ensure that both the baseline and the forecasts used for the mechanism have the same scope and relate to the same output assumptions.

1.22. If we introduce full or partial indexation of input costs, or volume drivers for certain cost categories, we are already mitigating the risks to DNOs, and stronger efficiency incentive rates may be appropriate.

1.23. As discussed in the Networks chapter, we are intending to distinguish between Type 1 companies that provide us with a robust set of measurable output targets that we can relate to their forecasts and then track through the price control period, from Type 2 companies that are unable to do so. One way of doing this is via the IQI. For example, we could give a lower additional income to the latter group. This additional income is effectively compensation for additional risk entailed in a higher efficiency incentive. Without robust outputs, a DNO may have more scope to defer capex in one area where another area is over budget and so the company faces a lower risk of cost overrun. Also, we might set a lower factor for the increase in allowed expenditure as the ratio increases, to reflect the fact that the case for additional capex is likely to be less convincing where it is not backed up by robust outputs. We could also consider the impact of applying different incentive rates, especially for underspending. Finally, although not visible from the IQI parameters, the way we set the baseline may be affected by whether a DNO has good justification for its cost forecasts in the form of the outputs it will deliver. There is likely to be a need for further challenge of forecasts where they are not sufficiently supported by output measures.

1.24. Tables 3 and 4 below are examples of different IQIs for companies that have robust and less robust outputs respectively. The parameters used are designed to illustrate the potential relative treatment of the different types of DNOs, rather than a guide to the eventual parameters we may choose. Compared to those in table 2, the parameters in table 3 are less generous for both the additional income and the allowed expenditure. This results in all outcomes being lower for the DNOs with less robust outputs by 1.5 per cent of our baseline (but it may be easier for that DNO to achieve a better outcome). This effectively extends menu regulation to output measures. Companies can self-select a better outcome by providing more robust output information. We consider that this may address some of Centrica's concerns that the rewards for underspending are too strong. Under this approach DNOs will only be able to obtain high rewards for underspending through genuine efficiencies.

Table 3 Example of IQI matrix for DNO with robust outputs

DNO:Ofgem Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.5	2.0	1.4	0.7	0.0	-0.8	-1.6	-2.5	-3.5
Rewards & Penalties									
Allowed expenditure	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Actual Exp									
85	8.5	8.1	7.5	6.8	6.0	5.1	4.0	2.8	1.5
90	6.5	6.2	5.8	5.2	4.5	3.7	2.8	1.7	0.5
95	4.5	4.3	4.0	3.6	3.0	2.3	1.5	0.6	-0.5
100	2.5	2.4	2.3	1.9	1.5	0.9	0.3	-0.6	-1.5
105	0.5	0.6	0.5	0.3	0.0	-0.4	-1.0	-1.7	-2.5
110	-1.5	-1.3	-1.3	-1.3	-1.5	-1.8	-2.3	-2.8	-3.5
115	-3.5	-3.2	-3.0	-2.9	-3.0	-3.2	-3.5	-3.9	-4.5
120	-5.5	-5.1	-4.8	-4.6	-4.5	-4.6	-4.8	-5.1	-5.5
125	-7.5	-6.9	-6.5	-6.2	-6.0	-5.9	-6.0	-6.2	-6.5
130	-9.5	-8.8	-8.3	-7.8	-7.5	-7.3	-7.3	-7.3	-7.5
135	-11.5	-10.7	-10.0	-9.4	-9.0	-8.7	-8.5	-8.4	-8.5
140	-13.5	-12.6	-11.8	-11.1	-10.5	-10.1	-9.8	-9.6	-9.5

Table 4 Example of IQI matrix for DNO with less robust outputs

DNO:Ofgem Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	1.0	0.8	0.4	-0.1	-0.6	-1.3	-2.0	-2.9	-3.8
Rewards & Penalties									
Allowed expenditure	100	100.5	101	101.5	102	102.5	103	103.5	104
Actual Exp									
85	7.0	6.6	6.0	5.3	4.5	3.6	2.5	1.3	0.0
90	5.0	4.7	4.2	3.7	3.0	2.2	1.3	0.2	-1.0
95	3.0	2.8	2.5	2.1	1.5	0.8	0.0	-0.9	-2.0
100	1.0	0.9	0.7	0.4	0.0	-0.6	-1.3	-2.1	-3.0
105	-1.0	-0.9	-1.0	-1.2	-1.5	-1.9	-2.5	-3.2	-4.0
110	-3.0	-2.8	-2.8	-2.8	-3.0	-3.3	-3.8	-4.3	-5.0
115	-5.0	-4.7	-4.5	-4.4	-4.5	-4.7	-5.0	-5.4	-6.0
120	-7.0	-6.6	-6.3	-6.1	-6.0	-6.1	-6.3	-6.6	-7.0
125	-9.0	-8.4	-8.0	-7.7	-7.5	-7.4	-7.5	-7.7	-8.0
130	-11.0	-10.3	-9.8	-9.3	-9.0	-8.8	-8.8	-8.8	-9.0
135	-13.0	-12.2	-11.5	-10.9	-10.5	-10.2	-10.0	-9.9	-10.0
140	-15.0	-14.1	-13.3	-12.6	-12.0	-11.6	-11.3	-11.1	-11.0

Appendix 10 - Pensions Background and Application Issues

Background to pensions review

1.1. In setting total revenue we consider and assess the efficient level of and the treatment of pension costs. In 2003[52] we set out six principles for the treatment of pension costs, in particular those arising from defined benefit (DB) schemes and have applied these with minor refinements through three price controls - electricity distribution (DPCR4), transmission (TPCR4) and gas distribution (GDPCR).

1.2. The DB schemes were originally the pension schemes of the nationalised gas and electricity industries prior to privatisation. At privatisation employees were given certain protected rights but most of the schemes are now largely closed to new employees. The aggregate DB current funding allowance[53] set for the monopoly networks is £441 million per year. The regulatory treatment provides that we allow the companies to recover their actual pension costs, provided that they are economic and efficiently incurred, at the subsequent price control. For DNOs actual deficit repair payments and normal contributions are forecast to exceed the DPCR4 annual allowances by around 7 per cent and we are advised by DNOs to expect further cost increases. We expect to see a similar trend of pension costs exceeding the price control allowances that have been set for the transmission companies.

1.3. In addition to increased deficits, there have been significant developments in the UK pension environment since 2003, including the Pensions Act 2004, which led to the introduction of The Pensions Regulator and the Pension Protection Fund (PPF). There have also been changes in mortality, investment yield assumptions, and the introduction of scheme specific funding. Since we set the principles we have continued to observe a sharp rise in employer contribution rates and deficit repair payments.

1.4. Given these changes in the UK pension environment, we considered it appropriate to review the working of the 2003 principles. To do this we issued a consultation in August - *Price Control Pension Principles*. In it and a subsequent seminar on 8 October, we consulted on a number of matters. As well as asking whether respondents would support any changes, we asked for views on when we should implement any changes. This could be achieved from the start of the next electricity distribution price control in April 2010 or, to consider them as part of our major review of our approach to network regulation through our 'RPI-X@20' project that is due to report in 2010.

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[52] Developing Network Monopoly Price Controls May 2003 (54/03)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=41&refer=Networks/Policy
[53] In GDPCR specific contribution rates were set rather than specific allowances.

1.5. Our aim is to assess whether the licensees and scheme sponsors are responding correctly to incentives to mitigate and manage pension costs effectively. We are concerned about the risk of creating the wrong incentives although we recognise that there may be a number of inbuilt protections against this risk. We are keen to understand the extent to which we can rely upon the fact that trustees are formally independent of the sponsor and that many of the schemes also include a significant number of members whose costs are funded by non-regulated businesses and as such have incentives to keep costs down.

1.6. In addition to the wider questions regarding the appropriateness of our pension principles, we also consulted on a number of more practical issues, including: setting an appropriate period for funding any deficit recovery payments; how pension costs and ex post adjustments interact with the Regulatory Asset Value (RAV); and the treatment of pension administration costs, including the PPF levy. Our current view on these issues is set out below.

Clarification on the application of our Pension Principles

1.7. In addition to the wider issues, the pensions consultation raised a number of application issues that both respondents and Ofgem agree require clarification as part of DPCR5.

Deficit recovery periods

1.8. Deficit recovery plans agreed with the Pensions Regulator arising for the 2007 triennial valuations of the Electricity Supply Pension Scheme (ESPS) have been set at anything from 3.4 to 8 years for funding the deficits. Some of these deficits will therefore be recovered in the remaining two years of DPCR4, and be subject to an ex post adjustment, with the balance in DPCR5. Whilst pension costs are trued up ex post and as actual deficit recovery periods vary, we consider that it is in the interest of consumers that the period over which deficits are to be funded in setting price control allowances should be generic rather than scheme specific. Under the principles these costs will be funded in due course. We are currently reviewing our approach to what might be an appropriate period. This is unlikely to exceed ten years (on an net present value (NPV) neutral basis) as that is the trigger applied by the Pension Regulator.

Ex post adjustments for DPCR4

1.9. Pension costs will follow the basis set out in DPCR4 Final Proposals and will be adjusted to actual net of tax. To the extent that 57.7 per cent was allowed into RAV, future revenues will be affected by over or under-funding. The adjustment is net of tax and we propose to use actual corporation tax rates, i.e. 30 per cent for the first three and 28 per cent for the last two years. These rates will apply to both the opex and capex elements as the cash costs of pensions are 100 per cent tax deductible as incurred. For the balance of 42.3 per cent of pension costs treated as opex, we are reviewing whether it is appropriate to spread the adjustment over one or five years and will finalise our view for initial proposals.

Capitalisation into RAV

1.10. Respondents have argued that deficit repair costs should be treated as opex, as passing any into RAV spreads the cash recovery over too long a period and does not incentivise employers to minimise costs. In DPCR4, deficits were spread on the same basis as normal contributions. These were not an issue at GDPCR. The DPCR5 treatment will be influenced by how we set RAV.

1.11. We are minded to continue the capitalisation into RAV of normal pension costs mirroring the treatment of total employment costs. This treatment may vary dependent on how we set RAV.

Appropriate actuarial valuation for setting price control allowances

1.12. Our practice has been to use the last triennial valuation when setting price control allowances. With the ongoing turmoil in the financial markets, since the last valuations were concluded, together with reports that deficits have increased significantly as a result, we invited views on what was the appropriate actuarial valuation to use when setting price control allowances. We were also mindful of the fact that valuation dates now differ across DNOs, which can affect the timing of funding deficits. DNOs consider it inequitable to fund pension costs based on only the latest valuation as funding levels would vary and some would suffer a cashflow disadvantage before the next price control true up. Also in DPCR5, most DNOs will face two further full valuations at March 2010 and March 2013.

1.13. We consider that there are three options to this issue:

- continue to use the latest available triennial valuation as this would reduce the cost to customers in the short term, accepting the potential true up in DPCR6 could or could not be a material amount, dependent on market conditions and investment strategies adopted by trustees,
- 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, or
- introduce a re-opener when a new regular full triennial valuation is published, provided that it will lead to material changes in contributions.

1.14. We would like to invite views on which option is appropriate.

Severance – Early Retirement Deficiency Contributions (ERDC)

1.15. As set out in the DPCR4 final proposals, these are paid for by shareholders as from 1 April 2004 and we intend to ensure adherence to this principle. We thus intend to examine whether there have been cases where deficit due to the pre-April 2004 ERDCs (which were in part disallowed in DPCR4), may have been recovered from the deficit payments made during DPCR4. We will work with licensees on an appropriate mechanism to compute this.

Pension administration costs and PPF Levy

1.16. Views were sought on our reviewing these for efficiency. Respondents have stated that trustees are sufficiently incentivised to ensure that the schemes' costs are efficient. We acknowledge this and, as the total costs are not material we will not benchmark them. We will review and normalise pension administration costs borne by the licensees compared to those that are funded through increased employer contributions.

1.17. We do not rule out subjecting the PPF Levy to an efficiency review but recognise that it is not necessary at this moment nor is it cost effective given the amounts involved. This is especially so for the risk based element which is outside the control of sponsors and trustees being dependent on the requirements of the PPF administrator. In addition, we will have a common and consistent treatment of the levy in setting RAV additions, which will follow the treatment of pension costs.

Treatment of scheme mergers

1.18. The application of the existing principle will be developed to ensure that the split of costs between regulated and unregulated members is reviewed and agreed with Ofgem at that time; and this will also apply to deficit repair payments. We are mindful that it may not be cost effective to have an annual actuarial assessment of this split. Accordingly, we will work with DNOs to agree the appropriate attributions.

Treatment of additional contributions to fund deficits following acquisition of a participating licensee or its group

1.19. Respondents agreed that there is scope for further improvement on the application of the principles in how these should be treated. We will develop a specific principle, including dealing with additional payments and the spreading thereof in setting allowances and the ex post adjustment. The principle should be flexible enough to cover most situations, but will allow for treatment on a case-by-case basis to cater for any unforeseen complexities.

Stranded surplus

1.20. Respondents agreed that both licensees and trustees take the potential for a stranded surplus to arise seriously. We intend monitoring schemes and expect symmetry in the treatment of a surplus with that for funding deficits. As such, if a scheme were in surplus for a given period we would consider our options when setting allowances such that consumers would benefit and the shareholders would cover the cost if contribution levels were not adjusted. Sponsors' and trustees' decisions would not be fettered, although they may be influenced by our treatment, as we do not have or seek the power to direct them.

New principle required on buyouts

1.21. The treatment of a buy-in or buy-out or the cost of the purchase of an annuity, is not covered by the existing principles. At present this is considered unlikely but may be an option in the future. We are minded to propose a new principle for consultation.

Summary of responses to the pensions consultation

1.22. The consultation posed a number of specific questions but many of the respondents also made a number of valuable general observations. The following section summarises these responses and observations. Where Ofgem has specific views on these issues, these are included in the main part of the policy paper and in appendix 10 above.

General

1.23. There was a general acceptance that it was appropriate to review the operation of our pension principles. Many respondents felt that the pension principles were fit for purpose and that it was the adherence to them that should be reviewed. One respondent felt that the principles failed to protect customers and set sufficient incentive to networks to reduce pension costs. Some companies also argued that as a proportion of their pension scheme members were not part of the regulated business, these schemes were already subject to commercial pressures.

1.24. Several respondents pointed out that Pension Trustees are independent with specific duties and responsibilities. The consultation paper did not intend to provide any guidance regarding the trustees' decisions and we can confirm that we are fully cognisant of the important role performed by Pension Trustees.

Specific questions – Chapter 3 Alternative approaches and new issues

Question 1: Have we identified the key issues with the current pension principles?

1.25. Nine licensees and twelve other respondents answered this question. Many respondents felt that the key issues had been identified. One DNO suggested that the treatment of ERDCs should be re-considered. One respondent felt Ofgem should address the risks in underlying pension scheme investment strategies whilst another responded that if Ofgem were to define an appropriate strategy for an industry or specific scheme this would change the balance of responsibilities between companies, trustees, regulator and pensions regulator.

Question 2: Do the principles need amending, and if so, what changes are required?

1.26. Nine licensees and nine other respondents answered this question. Most respondents were of the opinion that the principles worked well and expressed concern that changes would add instability and risk with potential implications for the cost of capital. Benchmarking of pension costs was seen as difficult (with some respondents strongly against) with one respondent suggesting that benchmarking of total employment costs could be undertaken to achieve this. Another respondent suggested licensees could take steps to reduce PPF levy costs and that failure to address these costs could be reflected in efficiency challenges. Most respondents only saw the need to provide clarification, where appropriate, in the application of the principles. Generally respondents wished to maintain the status quo to maintain regulatory certainty.

Question 3: Which issues should be addressed as part of DPCR5 and which issues are better dealt with as part of the RPI-x@20 review?

1.27. Eight licensees and three other respondents answered this question. The general view was that any major changes should be dealt with as part of the RPI-X@20 review; that the existing pension principles should not be changed prior to the end of the review as RPI-X@20 is the most appropriate vehicle for major change. Many respondents stressed the stability benefits of a long term set of principles and felt these should remain. One respondent identified that a consistent set of agreed principles should be valid under any form of regulatory control.

Specific questions – Chapter 4 Application issues

Question 1: Should we set a generic deficit funding period, e.g. maximum assumed by the Pension Regulator, or accept that proposed by the individual scheme actuaries?

1.28. Nine licensees and five other respondents answered this question. Many respondents identified the conflicting demands and duties of licensees, regulator and pension trustees as a major practical difficulty and the general consensus was that a scheme specific approach is required. It was suggested by one respondent that a joint approach with the Pensions Regulator might be beneficial.

Question 2: Views are invited on the approach to the treatment of full funding of a deficit and what alternatives there are to ensure consumers are not disadvantaged in any given price control period.

1.29. Seven licensees and one other respondent answered this question. Most respondents supported the status quo with deficits being funded over a reasonable period based on specific circumstances. One respondent felt that deficits should be funded over shorter periods since they generally related to a historic catch up and another that there were circumstances where making accelerated payments ahead of funding is efficient for companies.

Question 3: Should ex post adjustments be calculated by reference to the amount of the allowance, which takes no account of the impact of changes in defined benefit salary scheme costs, or by reference to the contribution rate, which automatically adjusts for such changes?

1.30. Nine licensees and three other respondents answered this question. There was general support for the existing system with concern that without ex-post adjustments the forecasting and setting of allowances would become crucial. One respondent suggested that additionally, as the DPCR5 period contains two revaluations for most companies, there should be a reopener or trigger to enable pass through on a year on year basis.

Question 4: What are respondents' views on the capitalisation of pension costs into RAV; and, whether there are any circumstances in which normal and deficit repair costs should be treated differently for RAV?

1.31. Nine licensees and three other respondents answered this question. Respondents agreed that there is scope for improvement on the application of the principles in how deficits should be treated. Many respondents felt that the treatment of pension costs should be consistent with other salary costs with respect to recovery through RAV. Conversely, six licensees identified deficit repair costs as operating cash costs in their financial reporting which called for funding on a pay-as-you-go basis. Some respondents argued that it was inappropriate to capitalise deficit repair costs since this was at variance with the treatment enforced by accounting convention.

Question 5: Are any steps taken to mitigate the risk based element of the PPF levy just deferring payment across time or can permanent savings be achieved?

1.32. Nine licensees and two other respondents answered this question. Respondents argued that trustees are sufficiently incentivised to ensure that a scheme's costs are efficient. Some respondents identified the PPF levy as being in the nature of an insurance premium. As such it was possible to mitigate the impact of the risk based elements of the levy. Other respondents felt that the levy is beyond their control or that they have already done what they can to reduce it. One respondent suggested that lobbying of the Pensions Regulator by Ofgem would be beneficial.

Question 6: Views are invited on the treatment of pension scheme administration costs (including the PPF levies) to ensure consistency, whether they should be subject to an efficiency review, and the treatment in RAV.

1.33. Nine licensees answered this question. Nearly all who responded to this question considered benchmarking unnecessary with one suggesting that schemes are already obliged to benchmark once every three years to ensure efficiency.

Question 7: Where schemes have been merged, should issues arising from applying the principles be dealt with on a case-by-case basis or should rules be developed to provide guidance?

1.34. Nine licensees and three other respondents answered this question. Most respondents felt that, because of the range of possible merger circumstances, it would be impossible to have set rules for dealing with such cases. Each merger should be treated on a case-by case basis. One respondent suggested that consumers should be entitled to benefit from any mergers immediately.

Question 8: Should it be obligatory to require an actuarial assessment of ongoing contributions and deficit repair payments to the individual constituent regulated and non-regulated businesses?

1.35. Nine licensees and three other respondents answered this question. Many respondents expressed concern that such an assessment would be difficult, costly and not particularly accurate. One respondent proposed that actuarial assumptions should be independently reviewed by Ofgem advisors.

Question 9: Where a licensee is taken over do the principles effectively deal with the treatment of any additional pension deficit repair payments?

1.36. Nine licensees answered this question. There was a difference of opinion as to whether the principles cover this. Some respondents said that they could be applied and that the takeover would be merely a timing change for the required deficit payment. Others felt that either the existing principles were not explicit or that a specific principle should be developed.

Other specific issues:

Buy-out of scheme liabilities

1.37. Eight licensees and eight other respondents commented on this issue. Views on this subject were varied but with a recognition that it is a complex area where there are few case studies to guide opinion. There was a commonly expressed opinion (seven respondents) that this is an unlikely option for most schemes in the short to medium term due to the size of the (currently) evolving market, the number of large schemes involved and the estimated cost (suggested by one licensee to be more than the total value of its existing scheme assets). Three respondents suggested greater clarity from Ofgem would enhance consideration of such matters.

1.38. One respondent argued that buy-outs can be more expensive than paying contributions to the fund. Another respondent suggested that, in view of the size of the schemes, any change to the principles should be looking at the gradual introduction of alternative de-risking strategies.

Common valuation basis

1.39. Five licensees and three other respondents commented on this issue. Moves towards applying common actuarial assumptions in setting price control allowances were not supported and concerns were expressed that such a move would influence trustees. One respondent felt that the Pensions Regulator states that trustee funding bases should reflect scheme specific investment strategies, mortality and demographic experience. As such, it argued that it would be inappropriate for Ofgem to impose a different basis to influence or use pension allowances to try to set the funding policy adopted by individual trustees.

1.40. One respondent thought that benchmarking would encourage short-termism but that Ofgem could highlight extreme outliers in terms of assumptions and/or valuations.

Stranded surpluses

1.41. Seven licensees and seven other respondents commented on this issue. Respondents to this subject argued that any surplus that arises is controlled by the trustees and not the licensee. Some observed that both employees and employers contribute to schemes and that any surplus would not necessarily reduce employer contributions thus benefiting consumers. Many respondents considered it unlikely for surpluses to arise in the future. This was on the grounds that trustees have set duties and would be more likely to de-risk their scheme rather than return any surplus; and at best consumers may expect a partial reduction in future contributions. One licensee claimed that treatment of deficits and surpluses are asymmetric with companies obliged to make good deficits but with no access to surpluses.

1.42. Some respondents expressed the view that consumers had benefitted from lower contributions rates in the past.

1.43. One respondent suggested that if surpluses did arise in the future, Ofgem could indicate that it will allow for only a reduced level of contribution (regardless of how much is actually paid into the scheme). This reduced level could be determined by reference to an efficient level of contribution into a scheme which holds such a surplus; this would be a factor which the trustees should properly take into account when settling the contribution rates with the employer.

Appendix 11 - Return on regulatory equity methodology

Introduction

1.1. As part of DPCR5, we have examined the performance of DNOs in DPCR4 in order to identify potential areas of improvements. A key part of this exercise is to make an assessment of each company's return on regulatory equity (RORE) over the price control period compared to the assumed return used in setting allowed revenues (7.5 per cent, post-tax, real[54]). We carried out this analysis by comparing the actual (for the first 3 years) and forecast (for the remaining 2 years) regulatory returns against the relevant items of the DPCR4 settlement.

1.2. The results obtained follow consultation on the methodology and source of data with the industry. The results are provisional and will be updated as necessary in the light of new data and any methodology considerations at initial proposals.

1.3. Our analysis addresses the following causes of material variance:

- opex
- capex
- tax rate
- interest rate
- incentives
- volume variances

1.4. Variances arising from differences between actual and modelled gearing are not being addressed at present as this could lead to misleading conclusions, bearing in mind that gearing (particularly with reference to the licensee's own gearing level) is essentially at the discretion of the owners.

1.5. Calculations are at 2002-03 price levels as with the DPCR4 modelling.

1.6. Pensions (for which we make ex post adjustments for differences between actual and forecast contributions) and pass-through items such as business rates have been stripped out of opex and capex expenditure. These items are fully recoverable either in the year the expenditure was incurred or in the subsequent price control, and so do not generate variances to returns.

1.7. Variances take account of the ex post adjustment of capital expenditure through the capex roller mechanism (see below). They do not take account of other ex post adjustments such as a pensions true-up, excess gearing claw-back, or re-openers relating to the period. The exclusion of pensions is discussed above.

[54] The IQI generated an additional income figure for each DNO, which was expressed as an additional return. However, since this was granted ex ante, it is not a factor in assessing the outturn variance, and for simplicity has been excluded.

The gearing claw-back is not material on current calculations. Re-opener income (for additional ESQCR[55] and TMA[56] costs) is available for some companies but not yet all, though this issue is due to be resolved in the next four months. Since we have not removed the costs for which this additional income will be allowed, returns will improve when the income is also taken into account, which we will do once we have figures for all DNOs and so can put them on a comparable footing.

Profiling

1.8. Price control revenues for DPCR4 were, broadly speaking, calculated as a five year total and applied evenly, in PV terms, throughout the period, a process known as profiling. So as to make meaningful comparisons, variances have been calculated for the total period rather than year on year. 'Actual' values are derived from outturn costs for the first three years and high level forecast business plan questionnaire (HLFBPQ) forecasts for the last two, with both outturn and forecast being updated as more up to date information becomes available.

1.9. Where forecasts are not available from responses to the HLFBPQ, projections for the two final years are made along the lines set out below for each variance. In the following sections we set out definitions of each of the above variances.

Splitting RAV between Equity and Debt

1.10. The equity and debt components of RAV have been split on the basis of the notional 57.5 per cent gearing in DPCR4. This follows the logic of the financial model, and provides stable base case RORE values for the period.

Opex and Capex

1.11. The outturn opex and capex figures (2005-08) have been taken from the RRPs, after adjustments to comply with our reporting rules. We have therefore excluded certain actual costs, such as restructuring costs that may be legitimately incurred by companies, but that do not meet our qualifying criteria. Forecast capex values (2008-10) have also been taken from the RRPs, with adjustments for pensions and related party margins. The RRP forecasts also allow us to derive opex figures, with certain limited assumptions (the cost categories used in the HLFBPQ differ in some respects, so are of limited use in assessing DPCR4 performance). The capex figures are then subject to the capex rolling incentive mechanism, which reduces the variance to between 29 and 40 per cent of the gross difference, depending on the DNO's incentive rate.

Tax Rate

1.12. Tax rates for both Corporation Tax and Writing Down Allowances reflect the new rates introduced in 2007. All other variances have been calculated as post-

[55] The Electricity Safety, Quality and Continuity Regulations 2002
[56] Traffic Management Act 2004

tax returns applying these actual rates. To the extent that the treatment of individual DNOs' capital expenditure is different from that assumed in the price control settlement, there may be further variances not captured here. There are, however, considerable practical difficulties in accurately quantifying these variances, which are typically timing rather than permanent differences in any case.

Interest Rates

1.13. We used market interest rates[57], deflated by actual annual RPI to arrive at the actual real interest rates to replace the assumptions in the weighted average cost of capital (WACC) calculation. Forecasts for 2008-2009 and 2009-2010 are the average of the values for the preceding years. Some DNOs have suggested that this may not take sufficient account of the extremely high capital costs currently observed in capital markets. We note this point, but also note that most DNOs have long-term funding arrangements in place, with a high proportion at fixed rates, so that their average cost of debt will not change significantly unless there is a sustained period of higher capital costs.

1.14. We are aware that specific funding decisions by individual DNOs mean that their actual finance costs will not exactly match a market benchmark. We have considered using actual debt costs in this calculation, but there are a number of complications. One is that differences in gearing may allow a DNO to achieve a higher credit rating and thus a lower interest cost than our modelled assumption, and so this cannot be considered in isolation from consideration of gearing differences. Another is that some DNOs are funded via intercompany loans, and so we would have to look outside the licensee to determine the ultimate financing costs (and indeed the ultimate gearing), which may not be straightforward.

Incentives

1.15. Losses and Quality of Service incentive schemes are compared with DPCR4 assumptions and a variance computed. Forecasts for 2008-2009 and 2009-2010 are the average of the values for the preceding years. DNOs have submitted alternative forecasts, but we have not had an opportunity to fully evaluate them. However, substituting these would not materially affect the overall picture. The impact of other incentives (additional income from connecting distributed generation, or creating regional power zones, discretionary rewards, the 20 per cent of innovation funding that must be financed by the DNO) is relatively immaterial.

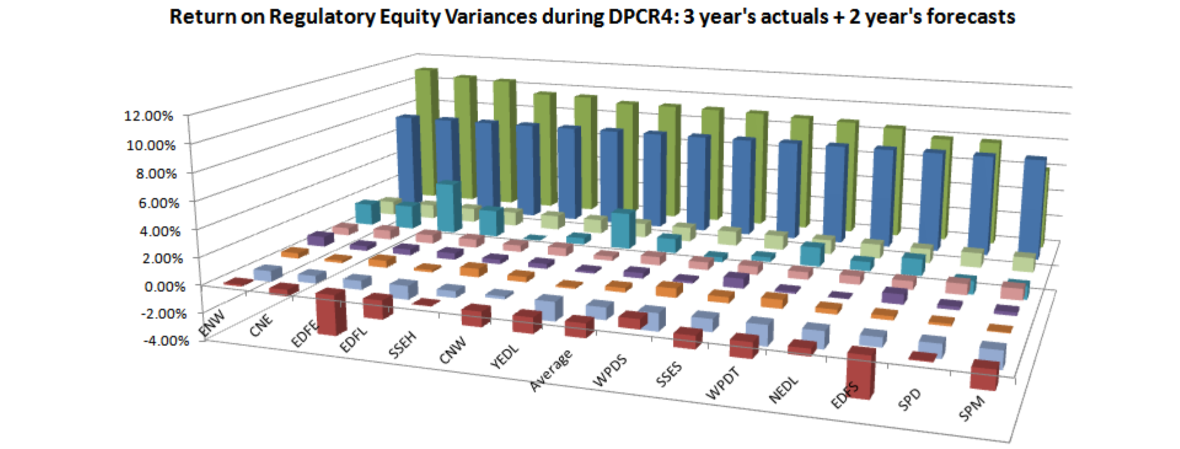
Volume variances

1.16. Actual volume-derived revenue, as reported, has been compared with DPCR4 assumptions. In this case, as there is a consistent divergence between forecast and actual values, the forecast years have been extrapolated from the first three years' outturns. DNOs have submitted alternative forecasts, but we

[57] Market interest rates are defined as the nominal 10 year trailing average yield of A and BBB-rated 10 year bonds, as reported by Bloomberg

have not had an opportunity to fully evaluate them. However, substituting these would not materially affect the overall picture.

Figure 1 Forecast RORE split by component variance



	ENW	CNE	EDFE	EDFL	SSEH	CNW	YEDL	Average	WPDS	SSES	WPDT	NEDL	EDFS	SPD	SPM
Opex	-0.13%	-0.48%	-2.93%	-1.36%	-0.03%	-1.08%	-1.13%	-1.01%	0.69%	-0.91%	-1.11%	-0.51%	-2.85%	0.08%	-1.34%
Revenue Drivers	-0.79%	-0.56%	-0.65%	-1.00%	-0.49%	-0.20%	-1.39%	-0.88%	-1.28%	-0.91%	-1.47%	-1.23%	-0.68%	-0.99%	-1.27%
QoS Incentive	0.40%	0.18%	0.52%	0.18%	0.62%	0.38%	-0.12%	0.32%	0.66%	0.42%	0.63%	0.34%	0.28%	0.17%	-0.06%
Capex	0.75%	0.36%	0.44%	0.48%	0.33%	0.36%	0.16%	0.39%	0.16%	0.71%	0.15%	0.03%	0.71%	0.23%	0.24%
Tax rate changes	0.57%	0.69%	0.65%	0.63%	0.49%	0.62%	0.32%	0.62%	0.57%	0.61%	0.54%	0.60%	0.62%	0.79%	0.82%
Losses Incentive	1.64%	1.80%	3.84%	2.02%	-0.02%	0.49%	2.71%	1.07%	-0.37%	0.34%	1.41%	0.68%	1.24%	-1.00%	-1.00%
Actual real interest rates	1.06%	1.06%	1.06%	1.06%	1.07%	1.06%	1.07%	1.07%	1.07%	1.06%	1.07%	1.07%	1.06%	1.08%	1.06%
DPCR4 ROE allowed	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
DPCR4 ROE achieved allowing for opex, capex, losses, QoS, volumes, tax, real interest	11.01%	10.55%	10.42%	9.52%	9.48%	9.13%	9.13%	9.08%	9.00%	8.83%	8.73%	8.48%	7.88%	7.85%	5.95%

CNE	Central Networks East Midlands	CNW	Central Networks West Midlands
EDFE	EDF Energy Networks East	EDFL	EDF Energy Networks London
EDFS	EDF Energy Networks South	ENW	Energy North West
NEDL	CE Electric UK North East	YEDL	CE Electric UK Yorkshire
SPD	Scottish Power Distribution	SPM	Scottish Power Manweb
SSEH	SSE Power Distribution Hydro	SSES	SSE Power Distribution Southern
WPDS	Western Power Distribution South Wales	WPDT	Western Power Distribution South West

Appendix 12 - DNO stakeholder engagement

1.1. In our initial consultation document we stressed that we expected all DNOs to undertake stakeholder engagement on a regional basis in order to inform their business plans. Outlined below is a summary of the stakeholder engagement completed by each DNO to date and a brief interim review of how useful this has been from Ofgem and the DNOs' perspectives.

1.2. We will publish further details of the DNOs' work in this area and the impact it has had on their business plan submissions in the initial proposals document in July 2009.

CE Electric

1.3. CE Electric split their stakeholder engagement into two stages. Stage one was qualitative research to review stakeholders' views of business priorities and was used to develop and prioritise specific costed options so that these could be discussed in stage two. Stage one involved a consultation document sent to approximately 6,000 stakeholders and which was also available online, six workshop events, MP engagement and six domestic customer focus groups.

1.4. For stage two, CE Electric undertook quantitative research which used the costed options developed during stage one to inform the right balance of business priorities. This stage comprised an online survey for business customers and face-to-face surveys with approximately 1,000 domestic customers.

1.5. The stakeholder workshops were held around the region with 75 attendees, ranging from local authority councillors and officials, major customers (demand and connections), energy consultants and environmental groups. Specific meetings were also held with regional development agencies (RDAs), North East Chamber of Commerce and the Engineering Employers' Federation. In addition to the regular engagement with MPs, all MPs were sent copies of CE's consultation document. Separate meetings were held with three MPs with particular energy interests.

1.6. Copies of the consultation document were also sent to local authority councillors and chief executives, trade bodies, major customers, environmental groups and RDAs. The consultation document could also be accessed via CE's website, where a dedicated page had been posted since January 2008. The customer survey was added to the website in August 2008.

1.7. Formal feedback was gathered from workshop attendees with attendees asked to rate the session on a scale from very useful to not at all useful. 72 per cent of responses reported that the workshops were useful and only one respondent found the sessions not useful. The consultation document mail-out, focus groups and customer surveys were all rated as very useful although it was noted that business customers were more difficult to engage, with CE suggesting that a more useful primary approach in future might be through trade bodies such as Confederation of British Industry (CBI), Chambers of Commerce and the Engineering Employers' Federation. The MP events and the website were rated as useful.

Ofgem attendance

1.8. Ofgem attended the stakeholder event in Newcastle. The event was attended by around 25 attendees. CE opened the day with a general presentation followed by a number of individual presentations focused on the main topics outlined in their stakeholder consultation document. Each presentation was followed by a question and answer session.

1.9. The presentations by CE were clear and informative with the most benefit being gained if the consultation document had been read prior to the workshop. During the question and answer sessions the questions were wide ranging and not always related directly to the CE presentation. In some cases the questions where dominated by stakeholders with very specific interests. In all cases CE provided answers that addressed the question which led to a good, lively debate.

Central Networks

1.10. Central Networks (CN) designed their stakeholder engagement programme to enable a wide group of representative stakeholders to discuss and provide feedback via facilitated sessions on their DPCR5 investment proposals. CN used a variety of methods including a mail-out to selected stakeholders, workshops targeting different interest groups, representation at relevant conferences and a drop-in session with MPs in London. CN also used bilateral meetings with local authority resilience planners, distributed generation (DG) developers, external service providers, demand-side management developers, suppliers and trade unions. CN also set up a website outlining high-level principles relating to its proposals and a questionnaire seeking responses. This was supplemented by promotion in local press and on local radio and a prize-draw campaign on the E.ON UK intranet.

1.11. The stakeholder events comprised a presentation of their investment plans followed by discussion workshops. Each event focussed on different areas of interest including flooding, high impact low probability (HILP) events, customer representatives, DG and investment plans. Additionally, CN attended and presented at the Energy Networks Association (ENA)/ Renewable Energy Association (REA) DG workshop, the National Association for Areas of Outstanding Natural Beauty (NAAONB) conference, the East Midlands Expo 2008 and the E.ON Energy Services Developer Day. DPCR5 was also featured as a presentation and discussion topic at CN's supplier day.

1.12. The big challenge noted by CN was engaging 'ordinary' domestic customers. The MP event in July 2008 was not well attended and hence was rated by CN as not being as useful as it might have been. Mail-out invitations to attend workshops required follow-up phone calls in order to be effective. Generally the website, mail-out and bilateral meetings were considered to be useful with the stakeholder workshops, and particularly the DG workshop, rated as being very useful.

1.13. CN suggests that through their stakeholder engagement programme they have been able to foster and improve existing contact with key stakeholders. The process has helped to shape and direct their stakeholder engagement strategy for the future; particularly by underlining the success of targeting contact to key groups on specific topics and communicating with them through workshops and bilateral meetings.

Ofgem attendance

1.14. An Ofgem representative attended CN's DG workshop. The format for the event involved presentations followed by a feedback/discussion on specific questions. There were four tables of around eight people per table, with a recorder and facilitator at each table. At the conclusion of this part of the workshop each facilitator reported back to the group. The workshop was well organised, involved a reasonable mix of stakeholders and this led to a good, lively debate.

1.15. Ofgem representatives also attended the workshops on flooding and customers. CN were able to get a good spread of attendees to their customer workshop. They provided sufficient explanation via power point presentations to facilitate useful discussions amongst the group and maintain interest of the stakeholders throughout the event. Some of the attendees expressed an interest in maintaining a dialogue with CN during DPCR5 and beyond. The flooding workshop was targeted at EA, Local Authorities and other utilities. There was useful discussion around sharing of flooding information, overlapping flood defence works and funding, with agreement for further discussions and bilateral meetings.

EDF Energy

1.16. EDF Energy formally launched its stakeholder engagement process on 1 July 2008 with the publication of the consultation document 'Planning for the future of our networks'. This provided a detailed summary of the network development plans for their three Distribution Networks (London, South East and East of England). EDF Energy contacted 1,700 stakeholders who were given the opportunity to comment through 15 structured questions on an on-line questionnaire and through three regional workshops. The consultation website was developed and hosted by an external company to ensure that the consultation remained independent and all responses were captured and represented fairly. The consultation was live for the best practice benchmark of 90 days. Of the three workshops that were run in early September; the first was focussed specifically on the topic of capacity headroom, whilst the other two provided an opportunity for stakeholders to understand further and comment upon EDF Energy’s plans for each of its 3 DNOs in DPCR5.

1.17. EDF Energy also held a specific meeting for MPs and further face to face and telephone meetings with key stakeholders who were unable to attend the formal events. Both of these were considered to be useful in providing further feedback.

1.18. EDF believe that these mechanisms were very successful in getting feedback from stakeholders, with more than 120 participants who provided 270 individual responses. Every response was carefully considered with full and non attributable transcripts published on the external EDF Energy website. EDF Energy has now published its consultation response document on this website. This provides a clear insight for stakeholders to understand how EDF Energy proposes to incorporate their feedback into the final forecast business plan questionnaire (FBPQ) submission in February 2009. Each stakeholder who participated in the consultation has also been provided with a copy of this report and where required EDF Energy has contacted stakeholders directly to answer company specific questions and issues.

1.19. EDF Energy would like to continue with a formal stakeholder consultation process as part of future price reviews.

Ofgem attendance

1.20. Ofgem attended a stakeholder meeting focussed on headroom capacity which was well run and aimed to maximise participation. EDF Energy had identified headroom capacity as an area of concern to certain stakeholders and organised a meeting to address this specific issue, in addition to the general DPCR5 stakeholder workshops.

1.21. EDF Energy used a third party to organise and facilitate the event and tried to maintain a background/information only role in the meeting. This worked effectively. During the meeting there was a lot of interaction, participation and discussion by attendees.

Electricity North West

1.22. Electricity North West (ENW) used a series of three workshops to consult with regional stakeholders in conjunction with individual, national and regional key stakeholder meetings. The workshops were intended to allow stakeholders to be involved in progressive debate and to become familiar with the issues being discussed and provide feedback on ENW’s Investment Plans. These workshops were held between April and October 2008. ENW also met individually with a number of key MPs. ENW generated the invitation list for the workshops from their own stakeholder database which was reviewed before each event.

1.23. ENW found the workshops to be very useful as they generated lots of interaction with stakeholders providing useful feedback. Also, positive feedback was received from stakeholders who indicated that the events were mutually beneficial. The feedback received by ENW broadly confirmed support for their proposals with particular emphasis on HILP and flood protection issues.

1.24. ENW found that engagement with stakeholders via their website was not as useful although it has been used for publishing materials related to the stakeholder engagement exercise. ENW are continuing to receive positive feedback and useful responses to their consultation on ENW's Strategic Direction Statement. ENW intend to publish a summary of how all stakeholder interactions and feedback have been utilised in developing their Forecast Business Plan. ENW have found it difficult to engage with MPs and the local authorities as a group, and found individual meetings easier to arrange. For the future, ENW will consider more targeted events for specific stakeholder groups.

Ofgem attendance

1.25. Ofgem attended two of the stakeholder engagement workshops run by ENW. They were well attended and consisted of initial presentations following by roundtable discussions and feedback by the moderators on each table. The first workshop focused on the key issues facing the DNOs and this was an opportunity for both the DNOs and the stakeholders to get to know each other and exchange information and contacts. The second workshop focused on key areas such as the environment, customers and HILP and considered both the requirements of the networks, potential cost impacts and customers' willingness to pay. Both workshops were well run and there were lively debates amongst the participants.

Scottish Power

1.26. SP Energy Networks (SP) used their programme of stakeholder engagement to provide details of their proposed business plans and to gather stakeholder views on these, with the intention of incorporating these views into the final plans submitted to Ofgem. SP used a wide variety of media and methods to attempt to engage with as wide an audience as possible. These included stakeholder events held in Chester and Glasgow (over 800 invited - circa 20 attendees at each event), direct mailings, website information, customer focus groups and one to one engagements with a sample of key individuals, including business and community leaders and local councillors. SP are holding parliamentary / assembly events (for MPs, MSPs and Welsh Assembly Members) in December 2008 and January 2009.

1.27. SP deemed the stakeholder events and interviews to be very useful with slightly less value placed on focus groups. The attendees at all events provided valuable qualitative ratification of the business plans and were positive about the meetings. The customer focus groups revealed that there was confusion as to the role of a DNO but the events gave useful insight into the expectations of domestic customers. The website and mailings generated no direct response. Energy suppliers were invited to attend the stakeholder events but did not engage.

Ofgem attendance

1.28. An Ofgem representative attended the Glasgow workshop, which had around 30 attendees. The session began with presentations from SP and then split into three breakout groups covering DG, environment and competition in connections. The presentations by SP were clear and informative. However, there was little discussion or feedback from attendees following the initial presentations or during the DG workshop, which the Ofgem representative attended. Attendees were all encouraged to complete a questionnaire which was circulated by SP and this tried to capture their views.

Scottish and Southern Energy

1.29. Scottish and Southern Energy (SSE) focussed their stakeholder engagement on seeking feedback from stakeholders on their proposed business plans. They consulted with their stakeholders through their website, a mailing list, two stakeholder events, a number of multilateral events with developers and environmental groups and numerous bi-lateral meetings. SSE found that most of these methods gave very useful feedback, but found it difficult to engage with MPs and consumer groups. SSE received strong feedback from stakeholders suggesting that they were keen for the communication to continue. This was further demonstrated by the active stakeholder participation at all the sessions that were held (bi-lateral, multi-lateral and seminars).

1.30. The mailing list included Ofgem, local authorities, environmental groups, developers, renewable energy developers, suppliers, consumer groups, National Farmers' Union, MPs and MSPs. There were no specific events for MPs and MSPs however they were invited to the stakeholder events/seminars but they showed no interest. The details of the stakeholder events/seminars were posted on the SSE website and invitations were sent out through the mailing list.

Ofgem attendance

1.31. An Ofgem representative attended one of the stakeholder events. The seminar was well run and involved representatives from most of the stakeholder groups. The seminar began with presentations from SSE on key issues and investment areas which gave relevant background information for the subsequent discussion groups. The attendees were split into two groups and were asked a series of detailed questions. Each group then presented their thoughts at the end of the session.

Western Power Distribution

1.32. Western Power Distribution (WPD) used their programme of stakeholder engagement to provide stakeholders with a high-level summary of their business plans and engage with them in order to gather views on stakeholders' priorities. WPD launched their stakeholder engagement on 30 May 2008 and over 2,000 stakeholders were contacted personally by letter or email, including parish and community councils, MPs, large customers, suppliers, environmental bodies and emergency services. Four events were organised in July 2008 at Westminster, the Welsh Assembly, Cardiff and Exeter. WPD also attended the relevant forums such as the CBI and Emergency Planning to highlight the consultation.

1.33. WPD felt that the mailing worked well while the website also attracted responses from customers that had not been contacted directly. WPD were surprised by the level of response which was greater than expected and by the level of support for increased expenditure. As a result, they have included more additional initiatives in their draft Business Plan than they expected to.

1.34. WPD also feels that it got a better understanding of what the National Park and AONB groups want them to do in order to improve amenity although this option was not supported by other stakeholders.

1.35. There was a low response from the generator community to the initial consultation and further work was carried out in this area to inform the detailed business plan. Going forward, WPD would look at different ways of engaging with MPs, industrial customers, suppliers and generators to achieve a better response.

Ofgem attendance

1.36. Ofgem attended the stakeholder event in Cardiff. This was the first time that WPD had organised such an event and they hired a specialist consultant to run it. The event began with a presentation on the part of WPD regarding the various capex options, followed by a discussion at each of the two tables about the desirability of these options. A consultant representative sat at each table and a 'thermometer' system was used to identify the importance of each issue to the participants. At the end an 'average' view was reached by combining the outcomes of each table.

1.37. Overall the event was well organised and WPD were keen to engage in the discussion. Attendance, however, was lower than expected, which was a bit of a disappointment for WPD although they were pleased with the attendance at the Exeter event.

Overall summary

1.38. The general feedback from stakeholders seems to show general support for the business plans put forward by each DNO, although engagement with stakeholders has revealed that a higher level of DG is due to be connected than the DNOs had expected.

1.39. Workshops that were focussed on specific issues either for the entire session or through the use of breakout discussions, seem to have been the most valuable in gathering views and stimulating debate. There also seems to be a benefit in consulting with stakeholders using specific costed options as this allows them to understand the specific impact of an issue and to prioritise the items that they most value.

1.40. Ofgem believes that the introduction of further output measures would allow stakeholders to become more engaged in this type of engagement with their DNO, as this provides an understandable measure of performance and of the changes in the network over time.

1.41. At a recent Ofgem workshop, all of the DNOs discussed their views of the stakeholder engagement that they had undertaken to date. The DNOs are working together to share best practice in this area.

Appendix 13 - Consumer Challenge Group

Purpose

1.1. The Consumer Challenge Group was set up to assist Ofgem in ensuring that the consumer view is fully considered during the Electricity Distribution Price Control Review. We already have a programme of consumer research as part of the review but wanted to bring in additional consumer expertise for the following purposes:

- To enable us to get consumer input into some of the more complex issues that we are unable to address through market research, and
- To provide a 'critical friend' from the consumer's perspective ensuring that we have not missed any key issues and that the final package is a fair one for consumers.

1.2. The Group acts in an advisory capacity to help inform the Authority's decision-making process. The need for this Group was increased due to the abolition of energywatch in October 2008. Ofgem has committed to taking the Group's views seriously and giving them due weight in the deliberation process but we are not obliged to act on the views expressed. The Group (or representatives of the Group) will be given the opportunity to present at key intervals to the Committee of the Authority with the same frequency as the distribution network operators (DNOs).

Programme of activity

1.3. The programme of activity will centre on the key documents that the team will issue throughout the review process. The Group will also meet with the Committee of the Authority each time the DNOs are invited in to make representations

1.4. We expect the programme to progress as outlined in the table below, although this is subject to review.

Table 1 – Programme of meetings for the Consumer Challenge Group

Meeting 1: July 2008 Introduction / background meeting	▪ General discussion on the March consultation document ▪ Presentations and discussions from Ofgem on each of the key strands: customers, environment, networks, financial. ▪ Particular focus on the Group's comments on the Customers chapter testing, in particular, whether we have identified the key issues of concern to consumers and whether there are areas that have been missed.
Meeting 2: October 2008 Committee of the Authority meeting	▪ Challenge Group to meet with the Committee of the Authority to give their views on the March consultation document ▪ A pre-meet with the Ofgem team was arranged
Meeting 3: Autumn 2008 Discussion on draft Ofgem position on policy matters	▪ Particular focus on consumer policy ▪ Discussion of areas of particular interest to the Group as identified at the first meeting
Meeting 4: Spring 2009 Discussion of draft initial proposals	▪ Discussion regarding where the overall package is heading re: costs Vs outputs and customer service. ▪ Particular focus on key issues identified by the Group and the Ofgem team (e.g. pensions/business costs/stakeholder engagement by DNOs)
Meeting 5: Summer 2009 Committee of the Authority meeting	▪ Presentation of Group's views
Meeting 6: Autumn 2009 Discussion of draft final proposals	▪ Primary aim to ensure Ofgem has got the overall balance in the package right
Meeting 7: Early winter 2009 Committee of the Authority meeting	▪ Presentation of Group's views

The issues

1.5. We have held a series of four meetings with the Group so far. Ahead of the first meeting, the Group were provided with a copy of the initial consultation document and the supplementary appendices. Through discussion with the DPCR5 team, the Group devised a list of key areas to focus on for their first meeting with the Committee of the Authority. These were:

- the consumer research,
- worst served customers,
- measures of customer satisfaction,
- connections,
- losses,
- the impact of environmental issues on the DNOs, and
- output measures.

1.6. We are considering whether the Consumer Challenge Group should have a roundtable meeting with the DNOs to discuss the Group members' key areas of interest.

Appendix 14 - Initial impact assessment on proposed treatment of DG connected pre-2005

Summary

1.7. This initial impact assessment presents a high level analysis of the potential impacts of our proposal that DG connected pre-2005[58] should pay the same use of system (UoS) charges as DG connected post-2005. Since significant uncertainties remain, at this stage it is only possible to present an outline impact assessment. A fully quantified and detailed impact assessment will be published as part of the DPCR5 initial proposals.

1.8. At 31 March 2005[59] there was 12.9GW of distributed generation capacity which connected under the 'deep' connection policy and is covered by the current generator distribution use of system (GDUoS) exemption for the duration of DPCR4.

1.9. Pre-2005 connected DG represents the vast majority of current embedded generators, since only 442MW of 'relevant' DG has connected in the first three years of DPCR4[60]. This figure is far below DNOs' forecasts that around 10GW of DG capacity would connect during DPCR4[61], however the general sentiment is that DG uptake will accelerate over the remainder of DPCR4 and DNOs forecast about 7.7GW of DG will be connecting during DPCR5[62].

Key issues and objectives

1.10. The objective is to ensure the most efficient use of the system, which could be achieved when all users are liable for cost reflective UoS charges.

1.11. The following key issues shall be considered:

- A substantial amount of DG (almost 13GW) is currently not exposed to economic signals for ongoing use-of-system,

[58] Pre 2005 connected DG refers to DG that connected or received a connection offer before 1 April 2005.
[59] Source: ENA website http://www.energynetworks.org/spring/engineering/pdfs/DGSG/Connection_Activity_DNOs_Dec2005_rev3.pdf
[60] According to ENA's data (not directly comparable), a total of 967MW of DG connected during the first two and a half years of DPCR4.
[61] Forecast and actual figures are contained in appendix 9 of the DPCR5 initial consultation document.
[62] Source: Our processing on DNOs' forecast business plan questionnaire (FBPQ) submissions, August 2008.

- Revised charging arrangements for all DG shall recognise the different treatment of reinforcement costs before and after 1 April 2005, due to the shift in the connection boundary from deep to 'shallowish'.

Options

Option 1 - Do nothing

1.12. This option would continue the current charging framework, where only DG that connected after 1 April 2005 ('relevant DG') is liable for GDUoS charges.

Option 2 - Mandate revised charging arrangements

1.13. We propose to mandate DNOs to implement revised charging arrangements for all DG by 2012[63]. Such revised arrangements would make all DG liable for GDUoS charges, irrespective of their connection date, and may include compensation mechanisms where appropriate and proportionate.

1.14. Around 12.9GW of DG capacity that connected before 1 April 2005 is exempted from GDUoS charges until the end of DPCR4 and therefore do not take the costs (or benefits) they impose on the network into account in their operating decisions. As a consequence, the DG subsequently connecting would receive distorted signals from the charges they pay, since a significant proportion of DG is not paying charges.

1.15. Since the value of network capacity is not currently reflected to pre-2005 connected DG, this may lead to an inefficient level of network reinforcement costs which would be borne solely by the new connectees; which could in turn act as a disincentive. Alternatively a new generator could find it too expensive to generate in a location because existing generators are already located in the vicinity. Since 8GW of DG is forecast to connect in DPCR5 this is clearly a material cost issue and may have environmental impacts.

Impact on consumers

1.16. Option 2 is likely to result in a step change in the individual level of GDUoS charges, in so far as application of GDUoS charges is extended to a new category of network users. The direction of redistributions depends on the final UoS charging methodology, which at present is unknown. We note that the new methodology intends to implement more cost reflective charging, which would ensure that the charges paid by a DG operator recognise any network benefits it provides in terms of deferred investments. The proposal also changes the degree to which costs are socialised among all DG as opposed to contributed directly from connecting DG.

[63] Such revised arrangements would have to build on a cost reflective charging methodology whose development is under discussion as part of the Structure of Charges project. Hence, we consider it appropriate to allow for a delayed implementation of revised charging arrangements for DG.

1.17. Option 2 does not affect the overall revenue stream available to DNOs to recover their efficient costs. It merely determines a change in the timing of recovery of such costs: compared to option 1, there would be a greater proportion of costs that, under the revised arrangements, would be recovered on an ongoing basis through GDUoS charges rather than upfront via connection charges.

1.18. We consider that in principle the efficient use of the system promoted by exposure to cost-reflective GDUoS charges under option 2 would in the long-run reduce overall costs to consumers.

Impact on competition

1.19. We consider that competition in generation is promoted when all generators face a common charging framework, as would be the case under option 2. Cost-reflective GDUoS charges, which could in principle be positive or negative, do not distort competition in generation as they fairly reflect the different costs imposed by different users.

1.20. Under option 2, DNOs shall develop appropriate compensation arrangements to ensure that pre-2005 connected DG is treated fairly and would be on a level playing field with newly connected DG.

1.21. We consider that the continuation of differentiated charging arrangements under option 1 would not be as effective as a common UoS framework in promoting competition in generation.

Impact on sustainable development

1.22. Exposure to a cost reflective charging methodology shall ensure the most efficient use of the system and hence can limit the need for network reinforcement. In this sense, option 2 may limit the environmental impact of electricity distribution networks. Under option 1 it would not be possible to send economic signals to existing DG in order to promote efficient system use.

1.23. It can be the case that under the proposals some forms of renewable energy sources (RES) that typically connect in remote areas may face positive GDUoS charges (thereby incurring an ongoing cost that they were not previously experiencing). Other DG would instead benefit from negative GDUoS charges. There seems to be no evidence at present that GDUoS charging impacts the feasibility of renewable schemes, nor have we found evidence that this could substantially undermine the feasibility of RES needed to meet EU renewable energy targets.

1.24. Under option 2 it is also possible that electricity losses will be reduced, because of better economic signals: cost reflective GDUoS charges aim to drive efficient decisions for use of and location on (siting or decommissioning) the system, as well as providing an incentive to develop commercial arrangements that may also have the effect of reducing losses at specific times, for example at system peak.

Risks and unintended consequences

1.25. Impacts on individual charges depend on the final UoS charging methodology, which aims to develop more cost reflective charging. For this reason it is not possible at present to quantify the impact of the proposals on different customers.

Other impacts, costs and benefits

Impact on existing DG

1.26. Under option 2, DNOs shall develop charging arrangements that provide pre-2005 connected DG with a fair compensation of the 'deeper than shallowish' element of the charge paid at the time of connection, so as to avoid notional double-charging. As a result, all DG would be on an equal charging framework going forward.

1.27. There is however an element of additional risk under option 2, due to the variability of GDUoS charges over time as compared to the certainty of an upfront deep payment with no associated ongoing GDUoS. Under option 1, instead, existing DG would not face any risk since it is not liable for GDUoS.

1.28. A cost-reflective charging methodology shall ensure that DG, as a group, are charged for the costs they impose on (or the benefits they provide to) the distribution system. However, the level of individual charges cannot be determined at present and could potentially be both positive and negative.

1.29. To limit such risks, it would be possible to agree contractual arrangements between DNOs and DG (e.g. to be constrained on or off at times of system stress, in exchange for lower GDUoS charges), and to develop hedging products against charges volatility.

Impact on DNOs

1.30. The proposals under option 2 entail a review of existing charging arrangements and where appropriate the development of a compensation methodology. We have received mixed responses from DNOs about the feasibility of such a compensation exercise. On the one hand, some DNOs have not expressed particular concerns and one in particular suggested that there are merits in considering the proposal. On the other hand, one DNO estimated that developing revised GDUoS arrangements for all DG in their two DSAs would require two and three man-years respectively. Given the variety of views it is not possible at this time to quantify the impact on DNOs. In any case it is possible that the impact will vary among them.

Appendix 15 - Initial impact assessment - Innovation and future networks incentive mechanism

Summary

1.1. This initial impact assessment presents a high level analysis of the potential impacts of the options we have presented in chapter 2 around encouraging the DNOs to innovate and invest for future requirements. Since the options are still under development, this impact assessment is by necessity very high level and qualitative. A proposal for innovation and future networks will be presented in the DPCR5 initial proposals, which will be accompanied by a fully quantified and detailed impact assessment.

1.2. Under the current regulatory framework there is little incentive for DNOs to change their current 'business as usual' methods of planning and operating their networks. They do not face competitive pressures to innovate and may perceive that they are unlikely to suffer if the future network proves to be inappropriate.

1.3. Innovation involves a risk of the DNOs losing money if a project fails or if additional costs are incurred in developing networks for the future that could be considered after the event to be inefficient. This risk further disincentivises the DNOs from innovating.

1.4. We do not think the existing DPCR4 incentives are sufficient to overcome the low risk, business as usual ethos of the DNOs. Therefore we propose to create a new mechanism which encourages a step change in DNO attitudes and actions.

Key issues and objectives

1.5. Our objective is to encourage the DNOs to anticipate how future changes in energy policy will impact their networks, involve themselves in the debate and be forward thinking in the way they continue to develop and invest in their networks. This could involve investing in equipment to provide more future flexibility or trialling innovative projects or commercial arrangements.

1.6. We have categorised this into two areas, future networks and innovation:

- future networks: we want DNO to consider whether they could invest in more expensive or different types of equipment that will provide more flexibility in terms of future network scenarios than the lower priced conventional alternative, and
- innovation: we want DNOs to consider more innovative alternatives to their usual network investments or commercial arrangements in order to create a long term lower cost and more flexible network. We recognise this means the DNO taking on more risk, which it will need to be compensated for. Our aim is

that this mechanism will encourage a small number of higher cost innovation deployment projects which we recognise will not be guaranteed to succeed.

Options

1.7. The options we are considering are based on three key drivers; when projects are assessed, the level and stage of project funding and whether additional rewards or penalties are applicable, depending on the outcome of the project. The options are not exclusive.

1.8. Option 1 - Ex-ante project funding: DNOs propose more flexible alternatives to current expenditure proposals in the forecast business plan questionnaire (FBPQ). Where proposals are allowed by Ofgem, we would provide assurances that any subsequent underutilisation of these assets due to changing environment would not result in the DNO being penalised or exposed to the full cost.

1.9. Option 2 - Project by project funding during DPCR5: DNOs submit project proposals to Ofgem during the course of the price control period. Ofgem would provide project approval taking into account upfront funding requirements, expected outcomes of the project and reward for successful completion.

1.10. Option 3 - Ex-post assessment of outcomes: At the end of DPCR5 we could provide a significant discretionary reward to those DNOs who have successfully improved their network flexibility or implemented innovative solutions. In addition, or alternatively, having been clear on our expectations of DNO behaviour at the start of DPCR5, we could compare DNOs' network developments at the end of the period, and penalise (through future allowances) any DNO deemed not to have innovated or improved their network flexibility to address the changing environment.

1.11. These options can be compared to a base case option where the existing Innovation Funding Incentive (IFI) and Registered Power Zone (RPZ) are retained but no further incentives are proposed. As explained in chapter 2, we doubt that this option by itself would be sufficient to incentivise the DNOs to invest in equipment to provide future flexibility or trial innovation projects or innovative commercial arrangements.

Impacts on consumers

1.12. This mechanism aims to balance the short term versus long term financial risk faced by consumers.

1.13. Across the three proposal options, there is the risk that some investment or innovation projects may not be fully utilised or successful, and therefore consumers' money will not be usefully employed. However we consider that this risk is significantly less that the risk faced by the consumer under the base case option. In this option, due to the lack of innovation or investment for future flexibility, the future networks may not be able to accommodate the environmental and energy policy objectives (such as significant DG) without incurring restructuring costs that could have been avoided if anticipated earlier, or unnecessary investments may be made in the short term which result in future stranded assets.

1.14. Over and above these macro risks, each of the three proposal options has a different sharing of risk between the DNO and the consumer.

1.15. Option 1: The consumer bears most of the short term risk, since the option provides guaranteed funding ex-ante, with little downside risk to the DNO. This option has a reasonable probability of incentivising the DNO to innovate, since they are not risking their money, although it does require them to anticipate required innovation in advance. Since there is little insurance that the DNOs make the best use of the allowed revenues to prepare for the future, it may be necessary to combine this option with an ex-post assessment based on the outcomes of the projects each DNO implements.

1.16. Option 2: DNOs and consumers would share the short term risk, since DNOs would only be allowed to pass through a percentage of the project cost. Consumers would bear most of the risk, but with the anticipation of longer term financial benefits when the project is replicated across other DNOs. Risk of the DNOs failing to implement the project would be reduced by the DNO financial contribution reward for successful completion.

1.17. Option 3: In this option DNOs bear the short term risk, since they implement the project without guaranteed funding or reward. This may make the DNO less inclined to innovate, thereby increasing the long term consumer risk, although this will be mitigated to an extent through the significant potential reward. This option would allow the DNOs to consider developing their ideas and investment plans over the review period in reaction to changing circumstance, which may make any innovation more appropriate and less liable to failure.

Impacts on competition

1.18. In all options, all DNOs will have equal opportunity to undertake projects, which will be evaluated on a transparent and consistent basis. We will approve or reward projects that are suitable for roll-out in other distribution services areas (DSAs), to provide all DNOs with the opportunity to gain the benefits of the innovation developed.

Impacts on sustainable development

1.19. The objective of this mechanism is to encourage the development of new techniques such as active network management (ANM) and demand side management (DSM) which will assist the achievement of the UK renewable energy targets. ANM techniques will facilitate the connection of distributed generation – both renewable energy and local generation (which can reduce losses). DSM can reduce demand (either overall or at peak) thereby reducing potentially non-environmentally friendly generation requirements. Therefore this mechanism will increase the sustainable development of the networks. As explained before, it is highly unlikely that these techniques would be developed under the base case option.

Impacts on DNOs

1.20. Any successful mechanism will have to overcome the financial risk faced by the DNO shareholders, such as the capex incentive if cost exceeds budget or the quality of service incentive if the customer service is reduced. As explained in the customer impacts section above, each of the options has a different level of risk for the DNO (which is the inverse of the level of consumer risk).

Risks and unintended consequences

1.21. There is a risk that the selected option does not sufficiently incentivise the DNOs, and therefore they do not propose or implement any (or limited) innovation projects. The consequences of this may be that DG cannot connect (due to a lack of network capacity or high cost of connections), the networks have to be reinforced (to enable the DG connection) with customers bearing the cost, DNOs do not optimise the power flows on their networks (causing a higher total cost of power) or customer service degrades.

1.22. Another risk is that only a small proportion of the approved projects are successful. This risk is mitigated by the project approval process and the requirement of the co-funding by the DNO. However, if there is a high failure rate, the consumer will have funded non-useful projects.

Appendix 16 - Initial impact assessment - Worst served customers

Summary

1.31. The initial consultation document raised the issue of improving the performance for the worst served customers and suggested three possible mechanisms to tackle the issue. The three options suggested in the initial consultation document were investigated, however it was decided that they probably would not result in the desired performance improvements. An additional allowance mechanism was also investigated and all four of these options are described in detail later.

1.32. We consider that a defined allowance is the most practical way to encourage investment to improve performance for worst served customers. As discussed in appendix 7, the total allowance would cover the five years of DPCR5 and would be spread equally across all of the DNOs. The major impact will be a more secure and reliable electricity supply for worst served customers.

1.33. The proposed allowance would have no impact on competition and a minimal impact on the environment/sustainability. There may be environmental benefits if DNOs opt for non-network solutions. Depending on the type of solution implemented, some of the proposed worst served customers schemes could help reduce losses and carbon emissions.

1.34. DNOs would be required to submit their proposed worst served customer schemes on an annual basis. A section of these proposals will cover the progress of completed schemes, which will help Ofgem to determine the value for money for the proposed scheme. There will be an overall review of the scheme after 4 years with the view to inputting into DPCR6.

1.35. Table 1 below gives an indication of the overall costs and benefits associated with each of the proposed options. A more detailed overview of the options and respective costs/benefits is given in later sections.

Table 1 - Costs and benefits summary

Worst served customer mechanism	Secondary description	Costs (£m)	Performance improvements	Cost per customer
Option 1 Do Nothing	N/A	0	X	√√√
Option 2a	1 interruption of 6 hours	177.4	X	X
	1 interruption of 12 hours	41.1	X	√√
	1 interruption of 18 hours	8.4	X	√√√
Option 2b(i)	3 interruptions of 3 hours	10.9	X	√√√
	3 interruptions of 2 hours	13.0	X	√√√

Worst served customer mechanism	Secondary description	Costs (£m)	Performance improvements	Cost per customer
	2 interruptions of 2 hours	27.4	X	√√√
Option 2b(ii)	GS2 = 6 hours	30.4	X	√√√
	GS2 = 12 hours	92.8	X	X
Option 3a&b	Maximum increased improvement	16.3	√√	√√
	No improvement	0	X	√√√
	Maximum decreased improvement	-16.3	X	√√
Option 4a	Based on UG costs	74.0	√√	√
Option 4b	Based on projected worst served customer costs	69.0	√√	√
Option 4c	Based on previous QoS costs	42.0	√√	√√

1.36. Table 1 is a high level summary of the associated costs and the likelihood that the mechanism will deliver the desired performance improvements. The costs are in terms of total costs and the cost per customer. The delivery of performance improvements is based on the delivery of reduced interruptions.

Key issues and objectives

1.37. Existing performance related incentives have been successful at improving the average reliability across all customers. These incentives have not been successful at improving the performance of the worst served customers. Providing compensation for customers with poor reliability or encouraging performance improvement should help to reduce the gap between the average and the worst served.

1.38. If the 'do nothing' option is taken, the worst served customers will most likely continue to pay for improvement that they do not receive. Although the performance improves for only the average customers, all customers need to pay for the reward to the DNO. Furthermore, the gap between the average performance and the performance of the worst served customers will continue to widen.

1.39. The objective of this impact assessment is to consider the costs and benefits of compensating customers with poor reliability or encouraging investment to improve the performance they receive.

1.40. The majority of worst served customers are situated on low density/ rural feeders. Under section 3A-(3)(d) of the Electricity Act 1989, Ofgem has an obligation to have regard to rural customers.

1.41. Ofgem also has an obligation to respect those living in rural areas under the Social and Environmental Guidance to the Gas and Electricity Markets

Authority, 23 February 2004. According to the Guidance, the consumers' interests include quality of service provided and the size of energy bills.

1.42. The objective contributes to the following Ofgem duties:

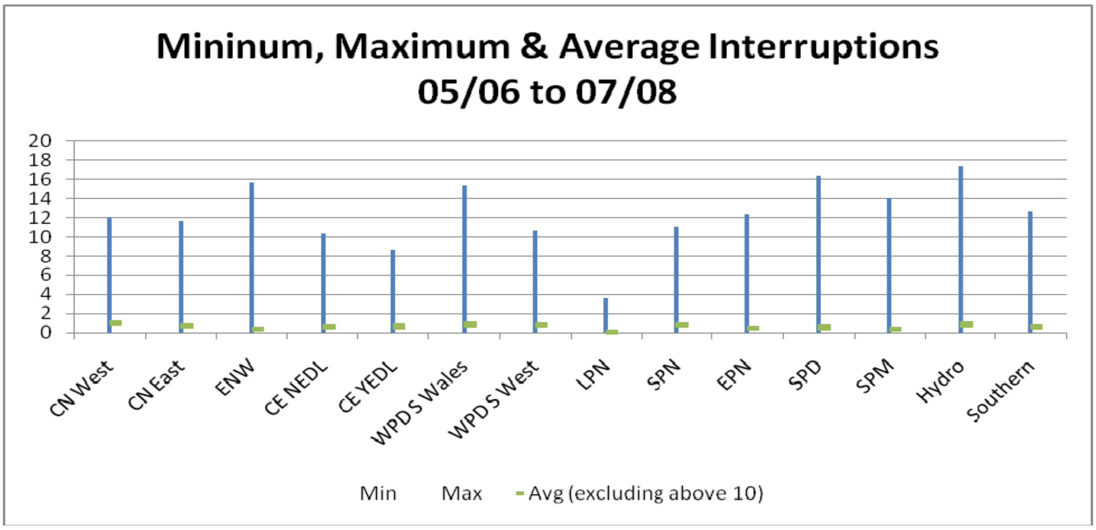
- Protecting the interests of consumers, present and future,
- Protecting the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas,

Options

Option 1 - No regulatory intervention

1.43. Figure 1 illustrates the performance received by worst served customers compared to the average customer. With no regulatory intervention, the performance levels experienced by the worst served customers would continue to be much worse than that experienced by the average customer.

Figure 1 - Average number of higher voltage interruptions so far during DPCR4



Option 2 - Guaranteed Standards of Performance (GSOP)

1.44. The two GSOP options considered were:

- Option 2a - Tightening the Guaranteed Standard of Performance GS2 supply restoration time under normal conditions (6 or 12 hours).
- Option 2b(i) - Tightening Guaranteed Standard of Performance GS2A multiple interruptions (3 x 3 hours, 3 x 2 hours, 2 x 2 hours)

- Option 2b(ii) - Introducing a compensation payment if a customer experiences aggregated duration of interruptions greater than a predetermined level for the year (6 or 12 hours).

1.45. Option 2 is aimed at increasing compensation for the worst served customers. The intention is to encourage DNOs to improve the network for worst served customers and/or compensate where performance is below the GSOP.

Option 3 - Incentive

1.46. Create an incentive for DNOs that is targeted at improving the overall reliability of supply to worst served customers. The incentive would be based on performance targets with a reward/penalty for over/under performance.

- Option 3a - Incentive based on total worst served customer population

- Option 3b - Incentive based on actual targeted worst served customers

1.47. This option involves a target based incentive on top of a defined allowance. Option 3a and 3b differ only in the way in which the targets are set. There is a capped reward/penalty for over/under performance.

1.48. Some preliminary work on Option 3 is in the Other impacts, costs and benefits section. This option will not be implemented during DPCR5 but the practicality of incorporating and/or moving toward an incentive based mechanism will be tested with a view to possible implementation in DPCR6.

Option 4 - Defined allowance

1.49. This option entails providing a defined allowance for DNOs that is available for projects that improve the overall reliability of supply for worst served customers.

1.50. One key issue with this option is setting an appropriate amount for the allowance. Some of the options considered for determining the appropriate amount were:

- Option 4a - an allowance based on the average costs for undergrounding for Areas of Outstanding Natural Beauty.

- Option 4b - an allowance based on the average cost per benefiting customer as set out in the DNO worst served customer proposals.

- Option 4c - an allowance based on an upper limit for costs per benefiting customer, limited to a cost similar to that already paid for quality of service.

1.51. Option 4a used the costs submitted for undergrounding schemes undertaken in DPCR4. Project costs for various proposed undergrounding projects were used to determine an average cost per customer (total customer base for all

DNOs excluding LPN). This average cost was then used to calculate the total allowance for various worst served customer bases. The customer bases were defined in terms of percentage of total customer base (0.5 per cent or 1 per cent), number of interruptions experienced (greater than or equal to 7, 8, 9 & 10) and fixed customer number (1,000, 2,000, 3,000, 4,000 & 5,000).

1.52. Option 4b involved taking the average cost per benefiting customer from a variety of projects and costs put forward by DNOs to address worst served customers. One DNO used real circuits that had been classified as worst served through a variety of definitions. Other DNOs provided a suite of improvement projects and their approximate costs.

1.53. The final option involved setting an upper limit on the cost per benefiting customer. We consider that the cost per benefiting customer should be in the same order that all customers currently pay for quality of service.

1.54. For DNOs to be eligible for the allowance under Option 4, they will be required to submit their proposed worst served customer schemes for approval by Ofgem. From the second year of DPCR5 onward, they will also be required to include an update on completed schemes as part of their submissions. Our initial thoughts on the rules for submissions under this mechanism are listed below:

- The customers benefiting from the proposed projects should have experienced, on average, five or more interruptions per year over the past three years,
- The proposed projects could be pre-existing projects that have been brought forward in order to accelerate the performance improvement for worst served customers,
- DNOs should only submit schemes that achieve a minimum performance improvement of 25 per cent for the targeted customers. Failure to deliver on this improvement could result in adjustments to their future allowance,
- The average cost per benefiting customer should not exceed £X (a number to be defined) over all projects in DPCR5,
- The £X (a number to be defined) can be calculated based on the NPV difference between the original planned date and the accelerated date of a particular project for worst served customers,
- The £X (a number to be defined) should also be calculated taking into account the reduced opex resulting from the proposed reduction in interruptions (i.e. the additional benefit should be netted off).

1.55. Given that there is high variability in the costs associated with various schemes, Ofgem has allowed the expenditure to be an average cost per benefiting customer. This should allow the DNOs the ability to balance more expensive solutions with less expensive ones. Ofgem proposes that the £X (a number to be defined) per customer is an average over all projects over the entire period. Ofgem invites views on what £X (a number to be defined) per customer should be used.

1.56. The other key issue with Option 4 is how to distribute the allowance amongst the DNOs. Some of the options considered for distributing the allowance were:

- Method A - fixed total allowance for all DNOs
- Method B - based on fixed allowance per total customers
- Method C - based on fixed allowance per total number of worst served customers
- Method D - based on fixed allowance per worst served customer as percentage of total customer base

1.57. Ofgem proposes that any amount relating to worst served customers in DPCR5 be split evenly amongst the thirteen DNOs having customers defined as worst served customer, as per Method A. This option would reduce the impact on customers in those DNOs with relatively high proportions of worst served customers.

Impacts on consumers

1.58. Under option 1, the current performance levels for the worst served customers would continue to deteriorate and the gap between the worst served and the average customer would continue to widen.

1.59. The cost per customer required to improve the performance for worst served customers will be relatively high. This is due to the relatively small proportion of worst served customers and the fact that they are typically located in rural/low-density circuits. With the relatively high cost in mind, Ofgem believes that option 2 would result in circulating penalty payments rather than an actual improvement in performance. This would result in higher energy costs without tackling poor quality of service, which is contrary to the consumer interests described in the Social and Environmental Guidance.

1.60. We consider that Option 3 would not deliver the desired performance improvements for customers, for the following reasons:

- Difficulty with setting defined outputs for one price control period
- No historical information on which to base reliable outputs
- Measuring improvements would require several years worth of data

1.61. With our current level of reporting and the lack of reliable target setting capabilities, Ofgem believes that an allowance mechanism will provide the greatest impact for customers. Option 4c seems to be the most reasonable approach for setting the available allowance. It should enable the delivery of performance improvements for the worst served customers with a reasonable cost per benefiting customer.

1.62. Historically, frequency and duration information has not been reported in terms of individual customers. In DPCR5, DNOs will be required to have individual customer interruption and duration information for all customers classified as worst served. This level of information should allow a greater understanding of the individual customer performance and also allow DNOs to develop schemes to target the customers that need the performance improvement. As the information is gathered throughout DPCR5, targets may be able to be set reliably which may drive further performance improvements for the worst served customers.

Impacts on competition

1.63. The majority of likely network solutions are not contestable. Therefore, any of the proposed options are not likely to have a significant detrimental effect on competition.

1.64. If the DNO employs non-network solutions there could possibly be some impact on distributed generation. Given the size of the defined allowance, the risk of detrimental impact on this market is considered to be very low. Furthermore, network solutions will most likely be more cost effective than non-network solutions and therefore the proportion of proposed non-network solutions is expected to be quite low.

Small businesses

1.65. All of the proposed options involve costs that would be spread across all customers equally. Regardless of the chosen approach, small business customers will not be disproportionately affected.

1.66. The mechanism is targeted at improving the performance for all worst served customers. Small businesses can be categorised as worst served customers as readily as any other customers. Therefore, some small businesses could benefit from the worst served customer mechanism.

Impacts on sustainable development

1.67. Non-network solutions may help the Authority to adhere to the guidance set out in the Social and Environmental Guidance to the Gas and Electricity Markets Authority, 23 February 2004. The guidance dictates the Government's expectations of the Authority with respect to its statutory duties, to seek to facilitate the achievement of the social and environmental objectives, targets and aims set out in the white paper.

Managing the transition to a low carbon economy

1.68. Non-network solutions may have a secondary benefit of reducing losses and carbon emissions, depending on the type of solution employed. This would aid the transition to a low carbon economy.

Eradicating fuel poverty and protecting vulnerable consumers

1.69. This may benefit vulnerable customers to the extent that they are on targeted circuits.

Promoting energy saving

1.70. There would be no impact in this area.

Ensuring a secure and reliable gas and electricity supply

1.71. This policy is directly focused on improving the performance of worst served customers. Options 2 to 5 would help to ensure a secure and reliable electricity supply for the worst served customers.

Supporting improvement in all aspects of the environment

1.72. There would only be minimal impacts in this area.

Impacts on health and safety

1.73. Depending on the type of faults being experienced by the worst served customers, there could be a reduction in potentially hazardous faults. This would directly reduce the exposure of customers and field resources to potential safety hazards.

1.74. Unplanned and frequent interruptions can cause customer appliances/devices to operate unexpectedly and/or cause permanent damage. A reduction in interruptions could indirectly reduce these potential safety hazards.

1.75. Options 3 and 4 aim to encourage expenditure on particular circuits in order to improve performance for the worst served customers. These options should result in a reduction of the frequency of interruptions on these circuits which will in turn reduce the associated potential safety hazards.

Risk and unintended consequences

1.76. The major risk associated with the 'do nothing' option is that the worst served customers will continue to pay for improvements in performance that they do not receive. Their current poor performance will continue to deteriorate whist the performance for the average customer improves.

1.77. Option 4 is aimed at encouraging DNOs to create projects that improve the overall reliability of supply to worst served customers. Due to the cost per worst served customer limitations, DNOs may not be able to find projects that are eligible for the allowance. This could lead to little or no improvement for the worst served customers.

1.78. Option 4 involves DNOs forecasting performance improvements as part of their worst served customer proposals. Due to the lack of information available, performance improvements are difficult to project reliably. There is a risk that Ofgem will deem certain projects to be eligible for the allowance, with expected performance improvements that do not eventuate. This could lead to customers paying for an improvement that they do not receive. However, the allowance is tied to the delivery of a specified minimum performance level. If DNOs fail to meet this level then their future allowance may be adjusted.

Distributional effects

1.79. This policy is aimed specifically at improving the performance of the worst served customers. Due to this fact, this policy will give an unequal distribution of benefits in favour of worst served customers over average and best served customers. However, this policy is aimed at correcting the observed unequal distribution of benefits by existing policies.

1.80. Option 4 would involve distributing a defined allowance amongst the DNOs with worst served customers. Since such customers have been defined as those customers experiencing five or more interruptions in a year, EDF LPN is not eligible to receive the allowance as they have no customers that qualify.

1.81. There are potential distributional effects associated with the distribution of the allowance to be provided under Option 4. It is proposed that the allowance is distributed evenly amongst the 13 eligible DNOs to minimise the impacts on customers from DNOs with high proportions of worst served customers and a relatively low total customer base.

Other impacts, costs and benefits

Option 2 - Guaranteed standards of performance

1.82. Table 2 is indicative of the amount of money that might be spent if GS2 were tightened to six or 12 hours as per Option 2a. These values are based on DPCR4 duration information and assume only the initial £50 payment is paid.

Table 2 - Option 2a - Approximate costs over DPCR5 (GS2)

Hours	Approximate costs (£m)
6	177.4
12	41.1
18	8.4

1.83. Table 3 gives an idea of the number of customers that could potentially benefit from this option.

Table 3 - Option 2a - Average number of customers benefiting per year (GS2)

Hours	Average customers per year (thousands)
6	710
12	165
18	35

1.84. Table 4 below is indicative of the amount of money that might be spent if GS2 were tightened to 3 x 3 hours, 3 x 2hours or 2 x 2hours as per Option 2b(i)

Table 4 - Option 2b(i) - Approximate costs (GS2A - tightening multiple interruptions)

Multiple interruption thresholds (frequency x duration)	£m for various percentages of customers within each band, assumed to be experiencing required multiple interruptions of appropriate length to exceed the various multiple interruption thresholds						
	100%	75%	50%	25%	10%	5%	1%
3x3 hours	10.9	8.2	5.5	2.7	1.1	0.6	0.1
3x2 hours	13.0	9.7	6.5	3.2	1.3	0.7	0.1
2x2 hours	27.4	20.6	13.7	6.9	2.8	1.3	0.3

1.85. The information in table 4 is based on the disaggregation by duration information. The available duration information does not specify the number of times that an individual customer has been counted within the duration band. For example, if there are 100 customers within the 3 to 4 hour duration band, theoretically there could be 100 customers each experiencing 1 interruption between 3 to 4 hours in length or 1 customer that had 100 interruptions between 3 to 4 hours in length. Therefore some assumptions were made about the number of individual customers in each interruption band. These assumptions are shown in the table as a range from 100 per cent to 1 per cent.

1.86. For the 3 to 4 hour duration band, you could assume that each customer had an average interruption of 3.5 hours. In order for customers within this band to cross the 3 x 3 hour tightened threshold they must have had at least 3 interruptions each. Therefore, if 100 per cent of customers within that band were to exceed the tightened 3 x 3 hour interruption duration standard, the duration band would have to consist of ((100/3) x 100 per cent) customers who each experienced 3 interruptions between 3 to 4 hours in length.

1.87. Alternatively, if only 1 per cent of customers within that band were to exceed the tightened 3 x 3 hour aggregated interruption duration standard, the duration band would have to consist of ((100/3) x 1 per cent) customers who each experienced 3 interruptions between 3 to 4 hours in length. Using the disaggregation by interruption data, these customer numbers, for the 100 per cent to 1 per cent scenarios, were then multiplied by the probability of experiencing 3 interruptions. These customer numbers were then multiplied by £50 to arrive at the numbers in the table above.

1.88. Table 5 is indicative of the amount of money that might be spent if GS2 were tightened as per Option 2b(ii).

Table 5 - Option 2b(ii) - Approximate costs (GS2A - total duration)

GS2 tightened threshold (Hours)	£m for various percentages of customers within each band, assumed to be experiencing the required respective number of interruptions to exceed the aggregated duration threshold of 12 hours						
	100%	75%	50%	25%	10%	5%	1%
6	30.4	22.8	15.2	7.6	3.0	1.5	0.3
12	92.8	69.6	46.4	23.2	9.3	4.6	0.9

1.89. The values in the table 5 above are based on the following:

- Information from duration bands with assumptions made about the frequency that a single customer experiences the required multiple interruptions to exceed the aggregated duration threshold.
- £50 payment
- Consideration of the possible tightening of GS2 to 6 or 12 hours, ensuring that customers receiving payments under either tightened GS2 do not receive additional payments from GS2A.

1.90. As with table 4, the percentages in table 5 represent the number of individual customers within each duration band. The only difference is that the GS2A total duration standard of 12 hours could be made up of a variety of interruptions of varying length. For example, 12 hours could be exceeded via 12 x 1 hour interruptions, 6 x 2 hour interruptions or 4 x 3 hour interruptions etc.

Option 3 - Incentive

1.91. In Option 3a the targets are set using the performance of the total worst served customer population. This option would be based on the following:

- Interruptions weighting - each additional interruption carries an additional 30 per cent weighting
- Target (X+Y=1):
    - X per cent industry 3 year average (including weighted interruptions)

- Y per cent individual 3 year average of DNO performance of all worst served customers (including weighted interruptions)

- Cap on maximum reward/penalty +/- £250,000

- Fixed Incentive Rate of £50,000

1.92. Tables 6 and Table 7 summarise the weighted interruptions and the range of costs for the high level incentive. The weighted interruptions are based on a weighting for each additional interruption above five. The second table shows the expected costs for scenarios where the maximum, the minimum and no performance improvements are achieved.

Table 6 - Weighted Interruptions

Actual Interruptions	Weighted Interruptions
5	5
6	8
7	11
8	15
9	20
10	28
>10	37

Table 7 - Range of expected costs for High Level Incentive

	Performance Improvement Scenarios		
Cost Description	**Maximum Increase**	**None**	**Maximum Decrease**
Reward/penalty (£m)	16.3	0.0	16.3
Total (£m)	48.8	0.0	0.0
Cost per benefiting customer (£)	48.08	0.00	48.08
Cost per customer (£)	0.63	0.00	0.63

1.93. This kind of high level approach could potentially see the benefit of individual schemes being masked by the total worst served customer population. For example, DNO one has around 100,000 customers experiencing greater than or equal to 5 interruptions per year. Compare this with DNO two which only has around 10,000 customers. Suppose both DNOs were to propose similar projects that benefited the same amount of customers, by the same amount, for the same price. It is clear that DNO two would appear to have a better improvement in measured performance despite the fact that the actual reduction in customer interruptions is identical. With this pitfall in mind, Option 3b is exactly the same as Option 3a only the performance data used to set the targets are based on the actual targeted worst served customers as opposed to the total worst served customer populations. This option will be investigated throughout DPCR5 as more reliable performance information is collected.

Option 4 - Defined allowance

1.94. Option 4a used costs taken from undergrounding schemes undertaken in DPCR4. These costs were used to calculate an average cost per benefiting customer and this value was then applied to the various worst served customer bases depending on the method chosen for defining worst served customers. The total costs and the calculated cost per benefiting customer were found to be disproportionately high compared to the amount that all customers currently pay towards quality of service. Table 8 below gives an example of the order for associated costs for the latter two methods of defining worst served customers.

Table 8 - Minimum costs for option 4a

	Total number of customers benefiting (average over three years)	Total funding allowance (using FBPQ) (£m)
Method 2 (9 interruptions)	19,000	£ 45.0
Method 3 (1,000 Customers)	14,000	£ 35.0

1.95. This option was considered to be too expensive both in terms of cost per total customer and per benefiting customer.

1.96. Option 4b used costs taken from the submitted worst served customer projects included in the August FBPQs. As with Option 4a the cost per benefiting customer was disproportionately high compared to the amount that all customers currently pay towards quality of service.

1.97. Table 9 below give an example of the order of associated costs for Option 4c. The table below shows the costs over the 20 year life of the asset.

Table 9 - Option 4c costs over life of asset (20 years)

£ 07-08	Cost description	Customer interruptions				
		7	6	5	4	3
£m	Total	23.3	28.9	42.3	68.9	131.9
£m	Per DNO	1.8	2.2	3.3	4.9	9.4
Thousand	Total worst served customers	74.1	152.3	337.9	746.9	1,695.6
%	(Total worst served customers) / (Total Customer Base)	0.26%	0.53%	1.18%	2.62%	5.94%
£	Per Customer	0.1	0.2	0.4	2.4	4.6
£	Per WSC	71.9	71.9	71.9	66.4	66.4

1.98. The values in table 9 are based on the following:

- capex allowance for DPCR4 £111.6m and projected for DPCR5 £193.4m.
- opex allowance for DPCR4 £113.5m
- exceptional events allowance for DPCR4 £24.5m
- projected savings in opex £18m due to reduced interruptions of 18 per DNO and an assumed cost of £5,000 per fault. It is assumed that the 18 saved interruptions would decrease to 0 over the 20 year life of the asset.
- LPN is excluded from all calculations for 6 and 5 interruptions as they do not have any customers in these categories.

1.99. Table 10 and table 11 are indicative of how any chosen amount would be distributed amongst the DNOs under the various options.

Table 10 - Percentage of total allowance distributed according to methods A-D

	Customers with >=5 interruptions per year (3 year average)	Total customers	£m option A	£m option B	£m option C	£m option D
CN West	67,051	2,415,484	8%	9%	20%	15%
CN East	36,890	2,549,112	8%	10%	11%	8%
ENW	19,383	2,325,155	8%	9%	6%	4%
CE NEDL	11,326	1,549,259	8%	6%	3%	4%
CE YEDL	15,010	2,225,253	8%	8%	4%	4%
WPD S Wales	27,518	1,080,697	8%	4%	8%	14%
WPD S West	22,528	1,498,199	8%	6%	7%	8%
EDFE LPN	0	2,213,479	0%	0%	0%	0%
EDFE SPN	33,477	2,218,054	8%	8%	10%	8%
EDFE EPN	17,147	3,457,682	8%	13%	5%	3%
SP Distribution	22,638	1,987,679	8%	8%	7%	6%
SP Manweb	12,761	1,479,569	8%	6%	4%	3%
SSE Hydro	25,368	710,383	8%	3%	8%	19%
SSE Southern	26,803	2,848,956	8%	11%	8%	5%
Total	337,900	28,558,962	100%	100%	100%	100%

Table 11 - Total allowance - £42 million distributed according to options A-D

	Customers with >=5 interruptions per year (3 year average)	Total customers	£m option A	£m option B	£m option C	£m option D
CN West	67,051	2,415,484	3.2	3.9	8.3	6.2
CN East	36,890	2,549,112	3.2	4.1	4.6	3.2
ENW	19,383	2,325,155	3.2	3.7	2.4	1.9
CE NEDL	11,326	1,549,259	3.2	2.5	1.4	1.6
CE YEDL	15,010	2,225,253	3.2	3.5	1.9	1.5
WPD S Wales	27,518	1,080,697	3.2	1.7	3.4	5.7
WPD S West	22,528	1,498,199	3.2	2.4	2.8	3.4
EDFE LPN	0	2,213,479	0.0	0.0	0.0	0.0
EDFE SPN	33,477	2,218,054	3.2	3.5	4.2	3.4
EDFE EPN	17,147	3,457,682	3.2	5.5	2.1	1.1
SP Distribution	22,638	1,987,679	3.2	3.2	2.8	2.5
SP Manweb	12,761	1,479,569	3.2	2.4	1.6	1.4
SSE Hydro	25,368	710,383	3.2	1.1	3.2	8.0
SSE Southern	26,803	2,848,956	3.2	4.5	3.3	2.1
Total	337,900	28,558,962	42.0	42.0	42.0	42.0

Post-implementation review

1.100. Part of the Option 4 proposal includes monitoring the performance of circuits/customers that have been targeted by expenditure under the worst served customer. Monitoring of the completed projects has been included to monitor the success of the proposed mechanism and to gain a better appreciation of the actual costs for remedial projects and the associated performance improvements. Where companies do not deliver the benefits that they forecast it may be appropriate to claw back some of the allowances.

1.101. The additional performance monitoring information will also allow the testing of other mechanisms. Throughout DPCR5 Ofgem will be using the additional information to test the appropriateness of incorporating or moving toward a performance based incentive scheme for DPCR6.

1.102. Ofgem also plans to review the overall performance of the scheme after 4 years with the intention of inputting to DPCR6.

Conclusion

1.103. Based on this impact assessment, Ofgem's initial proposal is to adopt a defined allowance as described in Option 4c with the defined allowance to be distributed amongst the 13 eligible DNOs (excluding LPN) equally as described in Option A.

Appendix 17 - DNO August FBPQs and Narrative

Overview

1.23. This appendix summarises the initial FBPQs submitted by the DNOs in August 2008. The DNOs were given the opportunity to update their FBPQs prior to the publication of this data. DNOs who did update their forecasts did not make wholesales changes. The changes were mostly corrections to data errors or changes to cost categorisations. In some cases DNOs updated incremental expenditure forecasts based on feedback received as part of their stakeholder engagement process.

1.24. Published alongside the data tables is a single page narrative from each DNO. These have been published as provided by the DNO. The contents of these narratives were solely determined by the DNOs.

1.25. Also shown is a combined all DNO forecast. An Excel spreadsheet version of the tables is also published on Ofgem's website (159b/08).

All DNOs - August FBPQ Summary

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
Total	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	703.9	713.2	901.6	853.1	852.1	989.2	1033.8	1030.3	1018.6	1011.1	4023.9	5083.0	26.3%
Customer contributions	537.8	602.4	658.2	568.8	566.4	583.3	588.9	589.4	591.2	588.4	2933.6	2941.2	0.3%
Load related (net)	166.1	110.8	243.4	284.3	285.8	406.0	444.9	440.9	427.4	422.7	1090.3	2141.8	96.4%
Non load related	555.6	653.4	740.6	806.8	834.0	1057.5	1095.4	1158.4	1159.7	1113.8	3590.4	5584.9	55.6%
Total	**721.7**	**764.2**	**983.9**	**1091.1**	**1119.8**	**1463.5**	**1540.3**	**1599.4**	**1587.1**	**1536.5**	**4680.7**	**7726.7**	**65.1%**
RPEs (net)				27.9	54.3	105.8	145.4	188.4	225.7	265.6	82.2	930.8	
Total (Including RPEs)	**721.7**	**764.2**	**983.9**	**1119.0**	**1174.0**	**1569.3**	**1685.7**	**1787.7**	**1812.8**	**1802.0**	**4762.9**	**8657.5**	**81.8%**
Distributed Generation													
Customer specific - Generation	23.2	28.8	30.3	77.9	179.9	110.2	122.0	123.8	148.9	139.0	340.2	643.8	89.3%
Customer contributions	14.4	39.7	31.7	68.0	152.3	88.2	97.1	102.4	121.2	112.2	306.1	521.0	70.2%
Total	**8.9**	**-10.9**	**-1.4**	**9.8**	**27.6**	**22.0**	**24.9**	**21.4**	**27.7**	**26.7**	**34.1**	**122.8**	**260.5%**
Network Operating Costs													
Inspections and maintenance	109.6	104.9	103.3	102.8	103.4	109.6	109.3	110.7	110.0	110.5	524.0	550.1	5.0%
Fault repairs and restoration	255.6	307.8	309.8	290.6	284.6	283.8	284.9	286.1	286.5	287.0	1448.4	1428.3	-1.4%
Tree cutting	69.9	67.1	76.9	83.1	109.8	111.4	109.2	106.5	106.3	105.9	406.8	539.3	32.6%
Other Network costs	1.9	-15.6	-13.3	-13.6	-13.6	-13.0	-13.6	-13.4	-13.5	-13.3	-54.3	-66.8	N/A
Total	**436.9**	**464.2**	**476.7**	**462.9**	**484.1**	**491.9**	**489.8**	**489.8**	**489.3**	**490.1**	**2324.9**	**2450.9**	**5.4%**
RPEs				8.3	15.5	23.1	30.7	38.9	46.7	54.8	23.7	194.3	
Total (Including RPEs)	**436.9**	**464.2**	**476.7**	**471.1**	**499.6**	**515.0**	**520.6**	**528.7**	**536.0**	**544.9**	**2348.6**	**2645.2**	**12.6%**
Indirect Costs													
Engineering Indirects	313.3	313.3	334.8	358.5	358.2	370.1	375.2	379.7	382.6	384.0	1678.2	1891.6	12.7%
Network/Investment Support	303.1	302.8	280.0	289.9	302.4	314.5	316.6	318.4	319.0	318.7	1478.1	1587.2	7.4%
Business Support	292.1	272.8	284.3	299.3	295.8	294.0	296.6	296.4	295.1	293.3	1444.2	1475.4	2.2%
Non-operational capex	58.8	75.9	83.9	85.0	82.7	107.6	97.6	84.0	82.4	90.2	386.3	461.9	19.6%
Total	**967.3**	**964.9**	**983.0**	**1032.7**	**1039.1**	**1086.3**	**1086.0**	**1078.5**	**1079.1**	**1086.2**	**4986.9**	**5416.1**	**8.6%**
RPEs				14.9	27.5	42.8	56.1	71.1	85.6	100.7	42.3	356.3	
Total (Including RPEs)	**967.3**	**964.9**	**983.0**	**1047.6**	**1066.6**	**1129.1**	**1142.2**	**1149.6**	**1164.6**	**1186.9**	**5029.2**	**5772.4**	**14.8%**
Total	**2134.8**	**2182.4**	**2442.2**	**2596.5**	**2670.6**	**3063.8**	**3141.1**	**3189.1**	**3183.2**	**3139.5**	**12026.5**	**15716.6**	**30.7%**
Total RPEs				51.0	97.2	171.7	232.2	298.4	358.0	421.0	148.2	1481.3	
Total (Including RPEs)	**2134.8**	**2182.4**	**2442.2**	**2647.5**	**2767.9**	**3235.4**	**3373.3**	**3487.5**	**3541.2**	**3560.6**	**12174.8**	**17197.9**	**41.3%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	475.2	484.1	579.3	560.0	557.5	577.4	590.6	588.1	582.8	576.9	2656.0	2915.8	9.8%
Diversions	34.0	39.9	47.4	42.1	43.2	54.4	49.6	45.9	48.3	51.8	206.5	250.1	21.1%
General reinforcement - P2/6	194.2	187.2	251.4	233.6	226.7	320.4	345.7	347.2	339.1	347.8	1093.2	1700.1	55.5%
General reinforcement - Fault Levels	0.5	2.0	23.6	17.4	24.8	32.0	41.1	35.5	28.3	14.5	68.2	151.4	122.0%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	5.0	6.8	13.6	20.2	20.1	0.0	65.7	N/A
Total Load related (Gross)	**703.9**	**713.2**	**901.6**	**853.1**	**852.1**	**989.2**	**1033.8**	**1030.3**	**1018.6**	**1011.1**	**4023.9**	**5083.0**	**26.3%**
Customer Contributions													
Customer specific - Demand	537.8	602.4	658.2	568.8	566.4	583.3	588.9	589.4	591.2	588.4	2933.6	2941.2	0.3%
Total Load related (Net)	**166.1**	**110.8**	**243.4**	**284.3**	**285.8**	**406.0**	**444.9**	**440.9**	**427.4**	**422.7**	**1090.3**	**2141.8**	**96.4%**
Non Load related investment													
Asset replacement	467.6	548.9	602.2	625.2	656.8	722.8	766.0	810.4	856.5	885.9	2900.7	4041.5	39.3%
Quality of supply (IIS)	40.0	56.0	56.5	41.0	31.5	44.8	40.3	39.9	36.4	17.8	225.0	179.1	-20.4%
Quality of supply (non IIS)	9.1	9.0	14.0	0.0	0.0	18.0	18.0	18.0	18.0	18.0	32.1	90.0	180.1%
Major system risks	0.0	0.0	0.0	3.4	2.2	26.9	34.9	59.8	57.7	32.5	5.6	211.8	3698.4%
Operational IT and telecoms	13.1	12.2	20.6	32.9	27.6	70.4	64.6	55.6	39.0	20.3	106.4	249.8	134.8%
Environmental	6.7	7.3	13.0	31.3	33.6	50.6	58.5	67.0	67.4	60.5	91.9	304.0	230.8%
Legal & safety	19.0	20.0	34.3	73.1	82.4	124.1	113.2	107.8	84.8	78.7	228.8	508.6	122.3%
Total Non Load related	**555.6**	**653.4**	**740.6**	**806.8**	**834.0**	**1057.5**	**1095.4**	**1158.4**	**1159.7**	**1113.8**	**3590.4**	**5584.9**	**55.6%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	3.4	2.2	22.5	20.3	23.2	24.2	22.9	5.6	113.2	1929.3%
HILP	0.0	0.0	0.0	0.0	0.0	4.4	14.6	36.6	33.5	9.6	0.0	98.7	N/A
Operational IT and telecoms													
BT21C			5.4	4.5	7.3	38.4	35.2	30.7	15.3	1.2	17.2	120.8	601.4%
Legal & safety													
ESQCR	0.0	0.3	3.6	51.9	60.5	67.9	55.1	53.3	36.9	31.9	116.3	245.1	110.8%
Environmental													
Visual Amenity	0.0	1.2	2.8	12.1	11.5	11.2	11.6	11.9	12.3	12.5	27.7	59.5	115.1%
Technical Losses				0.0	0.0	12.1	12.2	12.4	12.4	12.4	0.0	61.5	N/A
Tree cutting													
ETR-132			2.7	5.1	17.0	19.2	20.1	21.1	20.9	21.5	24.8	102.8	314.4%

Central Networks (West) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
CN West	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	34.5	56.9	65.4	60.4	52.2	65.1	74.8	82.0	83.2	82.5	269.5	387.6	43.8%
Customer contributions	5.7	42.1	54.2	46.9	40.9	41.4	42.6	42.6	42.6	42.5	189.8	211.7	11.6%
Load related (net)	28.9	14.8	11.2	13.5	11.3	23.6	32.2	39.4	40.6	39.9	79.7	175.9	120.7%
Non load related	47.5	66.4	74.0	60.4	58.4	78.9	85.7	90.8	84.0	86.8	306.7	426.3	39.0%
Total	**76.4**	**81.2**	**85.3**	**73.9**	**69.6**	**102.5**	**117.9**	**130.3**	**124.7**	**126.7**	**386.4**	**602.2**	**55.8%**
RPEs (net)				2.0	3.7	8.2	12.5	17.5	20.2	24.3	5.7	82.7	
Total (Including RPEs)	**76.4**	**81.2**	**85.3**	**75.9**	**73.3**	**110.7**	**130.4**	**147.8**	**144.9**	**151.0**	**392.1**	**684.9**	**74.7%**
Distributed Generation													
Customer specific - Generation	0.0	0.5	0.5	6.0	6.3	6.3	6.3	6.3	6.3	6.3	13.3	31.4	136.7%
Customer contributions	0.0	0.5	0.5	4.8	5.0	5.0	5.0	5.0	5.0	5.0	10.8	25.1	133.0%
Total	**0.0**	**0.0**	**0.0**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**2.5**	**6.4**	**152.5%**
Network Operating Costs													
Inspections and maintenance	6.8	8.7	9.9	9.2	9.5	9.1	9.5	9.2	9.5	9.3	44.1	46.6	5.6%
Fault repairs and restoration	27.2	30.2	25.3	23.0	20.8	20.4	20.8	21.2	21.3	21.5	126.5	105.2	-16.8%
Tree cutting	5.9	5.9	8.9	8.5	8.5	9.4	9.0	9.0	9.1	8.8	37.8	45.3	20.0%
Other Network costs	0.0	-2.3	-0.6	-0.8	-0.9	-0.9	-1.0	-1.0	-1.0	-1.0	-4.7	-4.9	N/A
Total	**39.9**	**42.5**	**43.5**	**39.8**	**38.0**	**38.0**	**38.3**	**38.4**	**39.0**	**38.5**	**203.7**	**192.2**	**-5.6%**
RPEs				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total (Including RPEs)	**39.9**	**42.5**	**43.5**	**39.8**	**38.0**	**38.0**	**38.3**	**38.4**	**39.0**	**38.5**	**203.7**	**192.2**	**-5.6%**
Indirect Costs													
Engineering Indirects	25.4	30.0	34.4	36.4	35.3	35.6	36.0	36.8	37.0	37.3	161.6	182.8	13.1%
Network/Investment Support	32.4	39.5	35.1	34.8	36.2	37.2	37.3	37.7	38.2	38.4	178.0	188.8	6.1%
Business Support	12.2	10.8	9.3	9.8	9.3	9.0	9.0	9.0	9.1	9.2	51.3	45.3	-11.7%
Non-operational capex	1.8	2.8	2.2	1.3	1.4	1.7	1.4	1.5	1.4	1.4	9.5	7.3	-22.9%
Total	**71.9**	**83.1**	**81.1**	**82.2**	**82.1**	**83.5**	**83.7**	**84.9**	**85.7**	**86.3**	**400.4**	**424.2**	**5.9%**
RPEs				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total (Including RPEs)	**71.9**	**83.1**	**81.1**	**82.2**	**82.1**	**83.5**	**83.7**	**84.9**	**85.7**	**86.3**	**400.4**	**424.2**	**5.9%**
Total	**188.2**	**206.9**	**209.8**	**197.1**	**191.0**	**225.3**	**241.2**	**254.9**	**250.7**	**252.9**	**993.1**	**1225.0**	**23.4%**
Total RPEs				2.0	3.7	8.2	12.5	17.5	20.2	24.3	5.7	82.7	
Total (Including RPEs)	**188.2**	**206.9**	**209.8**	**199.1**	**194.7**	**233.5**	**253.7**	**272.4**	**270.9**	**277.2**	**998.8**	**1307.7**	**30.9%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	13.4	30.6	43.9	40.6	33.2	33.6	34.5	34.5	34.5	34.5	161.7	171.6	6.1%
Diversions	5.1	5.8	6.0	5.7	5.5	6.9	7.1	7.5	8.2	8.2	28.1	38.0	35.0%
General reinforcement - P2/6	16.1	20.5	15.5	14.1	13.6	23.7	28.6	33.4	34.8	37.4	79.6	158.0	98.4%
General reinforcement - Fault Levels	0.0	0.0	0.0	0.0	0.0	0.0	3.7	5.7	4.9	1.5	0.0	15.8	N/A
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.9	0.9	0.8	0.0	4.2	N/A
Total Load related (Gross)	**34.5**	**56.9**	**65.4**	**60.4**	**52.2**	**65.1**	**74.8**	**82.0**	**83.2**	**82.5**	**269.5**	**387.6**	**43.8%**
Customer Contributions													
Customer specific - Demand	5.7	42.1	54.2	46.9	40.9	41.4	42.6	42.6	42.6	42.5	189.8	211.7	11.6%
Total Load related (Net)	**28.9**	**14.8**	**11.2**	**13.5**	**11.3**	**23.6**	**32.2**	**39.4**	**40.6**	**39.9**	**79.7**	**175.9**	**120.7%**
Non Load related investment													
Asset replacement	40.6	57.7	65.4	52.6	48.7	59.2	67.5	71.2	72.8	81.3	265.0	352.0	32.8%
Quality of supply (IIS)	5.9	5.9	5.9	4.2	3.9	6.6	6.6	6.5	4.6	0.1	25.9	24.4	-5.9%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0	5.5	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	1.9	2.3	4.7	1.1	1.1	0.0	11.0	N/A
Operational IT and telecoms	0.0	0.2	0.1	0.5	0.5	2.9	1.6	1.6	1.4	0.1	1.3	7.7	497.3%
Environmental	0.0	0.2	0.2	1.3	0.8	1.5	1.5	1.4	1.4	1.5	2.4	7.2	196.0%
Legal & safety	0.9	2.4	2.5	1.8	4.4	5.7	5.1	4.2	1.7	1.7	12.0	18.4	53.3%
Total Non Load related	**47.5**	**66.4**	**74.0**	**60.4**	**58.4**	**78.9**	**85.7**	**90.8**	**84.0**	**86.8**	**306.7**	**426.3**	**39.0%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0	5.4	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.8	1.2	3.6	0.0	0.0	0.0	5.6	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.8	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	0.9	3.5	4.0	3.5	2.6	0.0	0.0	4.4	10.0	125.7%
Environmental													
Visual Amenity	0.0	0.1	0.0	1.3	0.8	1.1	1.1	1.1	1.1	1.1	2.3	5.5	140.1%
Technical Losses				0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.0	1.7	N/A
Tree cutting													
ETR-132			0.0	0.0	0.6	1.2	1.2	1.2	1.2	1.2	0.6	5.8	929.4%

Central Networks (West) - August FBPQ Narrative

1.1. Central Networks is committed to delivering the network investment agreed with Ofgem for the DPCR4 period. We have reinvested the significant savings made as a result of merging Aquila and East Midlands Electricity to offset considerable price increases in materials. The forecast out-turn for DPCR4 therefore represents efficient delivery of the regulatory contract and a good deal for our customers.

1.2. During DPCR5 DNOs will face a real challenge in facilitating a low carbon future, improving network performance and accommodating load from new connections, whilst efficiently managing an ageing asset base. The DPCR5 business plan reflects our clear vision and strategy to deliver a safe, sustainable, reliable and efficient network and incorporates wide stakeholder consultation, including eleven events focused on customer service, distributed generation, flood protection, housing development, AONB and HILP security enhancements:

- The level of asset replacement investment has been set to prevent network performance deterioration by replacing those assets in worst condition. As a large proportion of the infrastructure is now over forty years old, this will result in a requirement to spend an additional 33% on this activity.
- Load related investment requirements are also increasing, largely driven by demands already exceeding P2/6 security limits. We are reassessing our plans given the current economic climate but, with recovery forecast for early 2010, major changes are unlikely. A thorough process has been used to develop our plans, which include the impact of DG, energy efficiency and smart metering.
- We have included efficient Quality of Supply investments designed to reduce interruption duration, and facilitate the introduction of network automation. Additionally, investment is also planned to improve supplies to small groups of 'worst served customers' in very rural areas where the network delivers particularly poor service.
- As part of E.ON, Central Networks is keen to secure energy supplies and shape the future role of DNOs. A key responsibility will be the facilitation of the connection of DG, where we forecast significant increases.
- We have also included investment for flood protection, city centre security, visual amenity and to reduce the network carbon footprint.

1.3. Our plans incorporate future cost improvements, delivered through a range of business alliances, which will efficiently deliver our work programmes whilst seeking only a 5% increase in indirect costs such as vehicles, designers and project managers, to deliver the increased work load. We are working with contractors and suppliers to ensure that they have the capacity to meet our needs, and have already placed orders for items of plant with long lead-times. We also believe we can achieve a 6% reduction in network operating costs through increased productivity whilst increasing activities such as inspections, maintenance and tree cutting to comply with new regulations and improve network performance.

1.4. Importantly, a suite of measureable outputs will demonstrate delivery of the plan, which we believe delivers value for current and future customers.

Central Networks (East) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
CN East	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	85.3	68.8	136.1	97.7	99.1	129.6	123.7	138.7	134.7	133.8	487.0	660.5	35.6%
Customer contributions	60.6	50.4	81.8	55.0	58.6	61.0	62.6	62.6	62.6	62.5	306.4	311.3	1.6%
Load related (net)	24.7	18.4	54.3	42.7	40.5	68.6	61.1	76.1	72.1	71.3	180.6	349.2	93.4%
Non load related	28.3	37.5	49.8	45.6	50.2	61.7	62.4	69.4	68.7	70.1	211.3	332.3	57.3%
Total	**52.9**	**55.9**	**104.1**	**88.3**	**90.7**	**130.3**	**123.5**	**145.5**	**140.8**	**141.4**	**391.9**	**681.5**	**73.9%**
RPEs (net)				2.3	4.9	10.4	13.4	19.9	23.5	27.8	7.2	95.0	
Total (Including RPEs)	**52.9**	**55.9**	**104.1**	**90.6**	**95.6**	**140.7**	**136.9**	**165.4**	**164.3**	**169.2**	**399.1**	**776.5**	**94.6%**
Distributed Generation													
Customer specific - Generation	0.0	0.2	1.0	24.7	25.5	25.5	25.6	25.8	25.8	25.5	51.3	128.2	149.8%
Customer contributions	0.0	0.2	1.0	19.7	20.4	20.4	20.5	20.6	20.6	20.4	41.3	102.6	148.4%
Total	**0.0**	**0.0**	**0.0**	**4.9**	**5.1**	**5.1**	**5.1**	**5.2**	**5.2**	**5.1**	**10.0**	**25.6**	**155.6%**
Network Operating Costs													
Inspections and maintenance	11.6	11.9	10.3	10.4	10.2	10.6	10.3	10.5	10.3	10.6	54.5	52.2	-4.2%
Fault repairs and restoration	28.6	34.2	30.0	28.3	25.7	25.1	25.6	26.1	26.3	26.4	146.8	129.5	-11.8%
Tree cutting	7.3	6.0	7.3	6.8	7.2	8.6	8.4	8.4	8.4	8.1	34.6	41.9	21.1%
Other Network costs	0.0	-3.6	-1.0	-1.8	-1.8	-1.8	-1.8	-1.9	-1.9	-1.9	-8.2	-9.4	N/A
Total	**47.5**	**48.6**	**46.6**	**43.7**	**41.3**	**42.5**	**42.4**	**43.0**	**43.1**	**43.2**	**227.8**	**214.3**	**-5.9%**
RPEs				0	0	0	0	0	0	0	0	0	
Total (Including RPEs)	**47.5**	**48.6**	**46.6**	**43.7**	**41.3**	**42.5**	**42.4**	**43.0**	**43.1**	**43.2**	**227.8**	**214.3**	**-5.9%**
Indirect Costs													
Engineering Indirects	30.1	28.5	25.1	26.2	25.2	25.4	25.6	26.1	26.3	26.6	135.1	130.0	-3.7%
Network/Investment Support	34.1	42.5	33.9	33.7	35.3	36.4	36.5	36.9	37.4	37.7	179.5	184.8	3.0%
Business Support	10.6	10.1	9.2	9.7	9.2	8.9	8.9	8.9	9.0	9.1	48.7	44.7	-8.2%
Non-operational capex	2.2	2.6	2.4	1.5	1.6	2.0	1.6	1.7	1.7	1.7	10.3	8.7	-15.6%
Total	**76.9**	**83.8**	**70.6**	**71.0**	**71.3**	**72.6**	**72.6**	**73.7**	**74.4**	**75.0**	**373.6**	**368.3**	**-1.4%**
RPEs				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total (Including RPEs)	**76.9**	**83.8**	**70.6**	**71.0**	**71.3**	**72.6**	**72.6**	**73.7**	**74.4**	**75.0**	**373.6**	**368.3**	**-1.4%**
Total	**177.3**	**188.3**	**221.4**	**207.9**	**208.3**	**250.6**	**243.7**	**267.4**	**263.4**	**264.6**	**1003.3**	**1289.7**	**28.5%**
Total RPEs				2.3	4.9	10.4	13.4	19.9	23.5	27.8	7.2	95.0	
Total (Including RPEs)	**177.3**	**188.3**	**221.4**	**210.2**	**213.2**	**261.0**	**257.1**	**287.3**	**286.9**	**292.4**	**1010.5**	**1384.7**	**37.0%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	54.5	39.0	91.7	70.8	69.5	73.3	75.4	75.3	75.3	75.2	325.5	374.4	15.0%
Diversions	5.9	4.4	8.2	6.4	7.1	15.0	7.4	7.8	8.4	8.5	31.9	47.1	47.6%
General reinforcement - P2/6	24.9	25.4	32.4	16.2	17.9	33.0	38.5	49.9	48.1	48.1	117.0	217.6	86.0%
General reinforcement - Fault Levels	0.0	0.0	3.8	4.2	4.6	7.2	1.4	4.6	1.7	0.9	12.5	15.7	25.2%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0	5.6	N/A
Total Load related (Gross)	**85.3**	**68.8**	**136.1**	**97.7**	**99.1**	**129.6**	**123.7**	**138.7**	**134.7**	**133.8**	**487.0**	**660.5**	**35.6%**
Customer Contributions													
Customer specific - Demand	60.6	50.4	81.8	55.0	58.6	61.0	62.6	62.6	62.6	62.5	306.4	311.3	1.6%
Total Load related (Net)	**24.7**	**18.4**	**54.3**	**42.7**	**40.5**	**68.6**	**61.1**	**76.1**	**72.1**	**71.3**	**180.6**	**349.2**	**93.4%**
Non Load related investment													
Asset replacement	24.6	30.4	40.7	38.9	41.3	44.0	44.5	52.6	54.8	58.6	175.8	254.6	44.8%
Quality of supply (IIS)	2.0	4.9	7.8	4.6	5.1	5.1	5.1	4.8	3.5	2.4	24.5	21.0	-14.5%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0	5.5	29778.2%
Major system risks	0.0	0.0	0.0	0.0	0.0	2.8	2.8	2.8	2.8	2.8	0.0	14.1	N/A
Operational IT and telecoms	0.4	0.0	0.0	0.5	0.5	3.5	3.7	3.4	3.3	1.9	1.5	15.7	951.9%
Environmental	0.0	0.4	0.1	0.2	0.3	0.7	0.7	0.7	0.7	0.7	1.0	3.6	256.2%
Legal & safety	1.3	1.7	1.2	1.4	3.0	4.5	4.5	4.0	2.4	2.4	8.5	17.9	110.2%
Total Non Load related	**28.3**	**37.5**	**49.8**	**45.6**	**50.2**	**61.7**	**62.4**	**69.4**	**68.7**	**70.1**	**211.3**	**332.3**	**57.3%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	2.8	2.8	2.8	2.8	2.8	0.0	14.1	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2	N/A
Legal & safety													
ESQCR	0.0	0.3	0.4	0.5	2.1	2.0	2.0	1.5	0.0	0.0	3.3	5.6	69.3%
Environmental													
Visual Amenity	0.0	0.3	0.0	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.6	1.8	180.9%
Technical Losses				0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.0	1.8	N/A
Tree cutting													
ETR-132			0.0	0.0	0.9	2.1	2.1	2.1	2.1	2.1	0.9	10.4	1034.1%

Central Networks (East) - August FBPQ Narrative

1.5. Central Networks is committed to delivering the network investment agreed with Ofgem for the DPCR4 period. We have reinvested the significant savings made as a result of merging Aquila and East Midlands Electricity to offset considerable price increases in materials. The forecast out-turn for DPCR4 therefore represents efficient delivery of the regulatory contract and a good deal for our customers.

1.6. During DPCR5 DNOs will face a real challenge in facilitating a low carbon future, improving network performance and accommodating load from new connections, whilst efficiently managing an ageing asset base. The DPCR5 business plan reflects our clear vision and strategy to deliver a safe, sustainable, reliable and efficient network and incorporates wide stakeholder consultation, including eleven events focused on customer service, distributed generation, flood protection, housing development, AONB and HILP security enhancements:

- The level of asset replacement investment has been set to prevent network performance deterioration by replacing those assets in worst condition. As a large proportion of the infrastructure is now over forty years old, this will result in a requirement to spend an additional 45% on this activity.
- Load related investment requirements are also increasing, largely driven by demands already exceeding P2/6 security limits. We are reassessing our plans given the current economic climate but, with recovery forecast for early 2010, major changes are unlikely. A thorough process has been used to develop our plans, which include the impact of DG, energy efficiency and smart metering.
- We have included efficient Quality of Supply investments designed to reduce interruption duration, and facilitate the introduction of network automation. Additionally, investment is also planned to improve supplies to small groups of 'worst served customers' in very rural areas where the network delivers particularly poor service.
- As part of E.ON, Central Networks is keen to secure energy supplies and shape the future role of DNOs. A key responsibility will be the facilitation of the connection of DG, where we forecast significant increases.
- We have also included investment for flood protection, city centre security, visual amenity and to reduce the network carbon footprint.

1.7. Our plans incorporate future cost improvements, delivered through a range of business alliances, which will efficiently deliver our work programmes whilst seeking only a 5% increase in indirect costs such as vehicles, designers and project managers, to deliver the increased work load. We are working with contractors and suppliers to ensure that they have the capacity to meet our needs, and have already placed orders for items of plant with long lead-times. We also believe we can achieve a 6% reduction in network operating costs through increased productivity whilst increasing activities such as inspections, maintenance and tree cutting to comply with new regulations and improve network performance.

1.8. Importantly, a suite of measureable outputs will demonstrate delivery of the plan, which we believe delivers value for current and future customers.

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ENW - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
ENW	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	53.7	70.8	79.8	59.9	57.2	82.0	89.9	73.2	75.4	73.7	321.6	394.2	22.6%
Customer contributions	37.5	68.5	60.8	43.6	45.6	44.6	47.5	51.0	53.3	55.9	256.0	252.4	-1.4%
Load related (net)	16.2	2.4	19.0	16.3	11.6	37.4	42.4	22.2	22.2	17.8	65.5	141.9	116.5%
Non load related	37.6	48.6	65.0	80.0	68.6	93.0	88.7	101.0	97.1	100.1	299.7	479.8	60.1%
Total	**53.9**	**50.9**	**84.0**	**96.3**	**80.1**	**130.4**	**131.1**	**123.2**	**119.2**	**117.9**	**365.3**	**621.7**	**70.2%**
RPEs (net)				1.8	3.0	7.3	9.9	11.9	14.0	16.3	4.8	59.4	
Total (Including RPEs)	**53.9**	**50.9**	**84.0**	**98.1**	**83.1**	**137.7**	**141.0**	**135.1**	**133.2**	**134.2**	**370.0**	**681.2**	**84.1%**
Distributed Generation													
Customer specific - Generation	1.9	2.3	9.1	4.4	5.2	8.8	8.8	10.3	11.5	11.5	22.9	51.0	122.9%
Customer contributions	2.3	6.3	9.9	4.2	5.2	7.9	7.9	9.1	10.3	10.3	27.9	45.4	62.8%
Total	**-0.4**	**-4.0**	**-0.9**	**0.2**	**0.0**	**1.0**	**1.0**	**1.1**	**1.3**	**1.3**	**-5.0**	**5.6**	**N/A**
Network Operating Costs													
Inspections and maintenance	7.0	5.5	6.1	6.9	6.8	9.4	8.9	9.4	8.9	9.3	32.3	45.8	42.0%
Fault repairs and restoration	20.8	20.5	20.2	20.6	20.4	20.4	20.4	20.4	20.4	20.4	102.5	101.9	-0.6%
Tree cutting	1.2	1.4	1.8	6.2	6.1	4.4	4.2	4.4	4.1	4.2	16.9	21.4	26.6%
Other Network costs	-0.9	-1.6	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-6.7	-7.0	N/A
Total	**28.2**	**25.8**	**26.7**	**32.3**	**31.9**	**32.8**	**32.1**	**32.8**	**32.0**	**32.4**	**144.9**	**162.1**	**11.9%**
RPEs				0.6	1.1	1.8	2.3	3.0	3.6	4.3	1.7	15.0	
Total (Including RPEs)	**28.2**	**25.8**	**26.7**	**32.9**	**33.1**	**34.5**	**34.5**	**35.8**	**35.6**	**36.7**	**146.6**	**177.1**	**20.8%**
Indirect Costs													
Engineering Indirects	35.5	36.1	29.1	31.6	31.2	35.3	35.3	35.2	35.1	35.1	163.5	176.0	7.7%
Network/Investment Support	16.9	13.1	10.7	10.3	10.3	17.3	17.4	17.7	18.1	18.2	61.3	88.7	44.8%
Business Support	38.1	33.4	37.0	43.0	39.7	39.1	38.9	38.7	38.5	38.4	191.2	193.7	1.3%
Non-operational capex	12.0	4.1	4.3	9.6	7.1	11.1	9.0	8.8	8.6	8.5	37.0	46.0	24.2%
Total	**102.5**	**86.6**	**81.1**	**94.5**	**88.4**	**102.8**	**100.6**	**100.5**	**100.4**	**100.1**	**453.0**	**504.5**	**11.4%**
RPEs				1.6	3.0	5.4	7.1	9.0	10.9	12.8	4.6	45.3	
Total (Including RPEs)	**102.5**	**86.6**	**81.1**	**96.1**	**91.4**	**108.2**	**107.7**	**109.5**	**111.3**	**113.0**	**457.7**	**549.8**	**20.1%**
Total	**184.2**	**159.3**	**190.9**	**223.4**	**200.4**	**267.0**	**264.8**	**257.6**	**252.9**	**251.7**	**958.2**	**1293.9**	**35.0%**
Total RPEs				3.9	7.2	14.5	19.4	23.9	28.5	33.4	11.1	119.7	
Total (Including RPEs)	**184.2**	**159.3**	**190.9**	**227.4**	**207.6**	**281.5**	**284.1**	**281.5**	**281.4**	**285.2**	**969.3**	**1413.7**	**45.8%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	38.4	55.8	49.4	43.4	45.4	44.4	47.3	50.7	53.0	55.7	232.5	251.2	8.0%
Diversions	2.4	2.1	2.9	2.3	2.7	4.4	8.0	3.7	3.6	4.8	12.3	24.5	99.7%
General reinforcement - P2/6	12.7	11.3	27.1	12.6	6.5	32.6	34.0	18.2	18.7	13.2	70.2	116.6	66.1%
General reinforcement - Fault Levels	0.2	1.7	0.4	1.7	2.6	0.3	0.2	0.6	0.1	0.1	6.6	1.2	-81.2%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.0	0.0	0.7	N/A
Total Load related (Gross)	**53.7**	**70.8**	**79.8**	**59.9**	**57.2**	**82.0**	**89.9**	**73.2**	**75.4**	**73.7**	**321.6**	**394.2**	**22.6%**
Customer Contributions													
Customer specific - Demand	37.5	68.5	60.8	43.6	45.6	44.6	47.5	51.0	53.3	55.9	256.0	252.4	-1.4%
Total Load related (Net)	**16.2**	**2.4**	**19.0**	**16.3**	**11.6**	**37.4**	**42.4**	**22.2**	**22.2**	**17.8**	**65.5**	**141.9**	**116.5%**
Non Load related investment													
Asset replacement	33.0	42.6	51.0	61.1	55.7	52.3	54.5	70.5	78.4	88.8	243.5	344.5	41.5%
Quality of supply (IIS)	1.9	1.8	0.7	1.1	0.9	1.9	1.1	1.1	1.1	1.1	6.4	6.5	0.8%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	0.0	10.0	N/A
Major system risks	0.0	0.0	0.0	1.6	0.0	3.6	1.0	2.9	2.4	0.4	1.6	10.3	557.4%
Operational IT and telecoms	1.4	2.6	5.8	8.8	4.8	14.7	10.6	9.4	6.1	0.9	23.5	41.6	77.2%
Environmental	0.1	1.0	3.9	1.3	2.2	2.6	2.6	2.6	2.6	2.3	8.5	12.7	49.8%
Legal & safety	1.2	0.5	3.6	6.1	4.8	15.9	16.9	12.5	4.4	4.6	16.3	54.3	233.4%
Total Non Load related	**37.6**	**48.6**	**65.0**	**80.0**	**68.6**	**93.0**	**88.7**	**101.0**	**97.1**	**100.1**	**299.7**	**479.8**	**60.1%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	1.6	0.0	3.6	0.7	0.2	0.7	0.4	1.6	5.6	254.2%
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.6	1.8	0.0	0.0	4.8	N/A
Operational IT and telecoms													
BT21C			2.5	3.2	1.3	7.3	5.9	4.4	1.5	0.0	7.1	19.2	171.4%
Legal & safety													
ESQCR	0.0	0.0	3.2	5.5	3.1	10.2	10.2	10.2	0.0	0.0	11.8	30.5	158.8%
Environmental													
Visual Amenity	0.0	0.1	0.1	0.9	2.1	0.8	0.8	0.7	0.7	0.7	3.1	3.8	21.5%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.9	0.6	0.4	0.7	0.4	0.5	0.9	2.6	185.6%

ENW - August FBPQ Narrative

1.26. The tables are the first submission of our 2010-2015 plans to Ofgem from August. They were based upon a number of key, high-level assumptions, which have continued to evolve as we analyse further asset and network data, consult with our stakeholders, refine our planned solutions and review the expected costs of our investments. We are also clarifying the outputs and benefits our investment is expected to deliver.

1.27. Our core strategy is to ensure the sustainable delivery of services to customers through maintaining the integrity, security and safety of the electricity network under normal and outage conditions. We maintain a stable risk against service failure by replacing assets as they reach the end of their serviceable life, and refurbishing assets to extend their life. To do this we will maintain overall asset fault rates at their current levels, despite an ageing asset base. We also plan to provide new capacity to customers to meet their requirements, ensuring sufficient capacity headroom in the system for both new loads and generation. This plan is consistent with ENW's strategy of facilitating the connection of new renewable generation.

1.28. Investments are planned to be consistent with upper quartile customer service, both in terms of timeliness and system performance using class-leading forecasting and planning tools. For general customer service measures, i.e. the number of and duration of interruptions, we will seek to maintain our existing good performance relative to other DNOs. We also propose to allocate appropriate investment to improving the network performance experienced by our worst-served customers.

1.29. Recognizing the criticality of electricity supply to modern society, we have identified appropriate and affordable opportunities to improve network resilience in a number of areas in terms of improving; the physical security of sites in the face of increasing malicious attacks and interference, the network's resilience to severe weather in the context of a changing climate and forecasts of increased frequency or such events, and the capability of supplies to key urban districts to withstand high-impact, low probability events.

1.30. Whilst many initiatives in this plan reduced costs, some historic, low-cost policy approaches have been identified as unsustainable and modified to ensure an efficient, long-term approach. Unit cost pressures were forecast to continue to influence project costs with above-RPI increases in material and labour costs of recent years predicted to continue due to global materials demand, increasing domestic labour requirements and an aging skill base. These forecasts must be reviewed to reflect the recent macro-economic changes.

1.31. We have identified appropriate and affordable network policies and investments that reduce ENW's carbon footprint. We will remain fully compliant with relevant environmental legislation and have identified further opportunities for improving the sustainability of our operations.

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CE (NEDL) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
CE NEDL	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	43.1	36.0	48.7	36.8	40.1	39.6	43.1	44.1	36.4	36.6	204.7	199.8	-2.4%
Customer contributions	34.5	30.0	33.4	27.4	29.5	28.9	28.2	28.0	28.0	28.0	154.8	141.1	-8.9%
Load related (net)	8.6	6.0	15.3	9.4	10.6	10.7	14.9	16.1	8.4	8.6	49.9	58.7	17.7%
Non load related	33.3	35.5	39.6	43.1	42.4	54.1	54.8	58.8	74.0	67.3	194.0	309.1	59.3%
Total	**42.0**	**41.5**	**54.9**	**52.5**	**53.0**	**64.8**	**69.8**	**74.8**	**82.4**	**75.9**	**243.9**	**367.8**	**50.8%**
RPEs (net)				0.8	1.4	2.3	2.9	3.7	4.4	4.6	2.3	17.9	
Total (Including RPEs)	**42.0**	**41.5**	**54.9**	**53.3**	**54.4**	**67.1**	**72.7**	**78.5**	**86.8**	**80.5**	**246.1**	**385.6**	**56.7%**
Distributed Generation													
Customer specific - Generation	0.4	0.2	0.2	0.2	0.6	11.7	12.5	12.8	2.8	3.2	1.7	42.9	2467.9%
Customer contributions	0.0	0.1	0.2	0.2	0.6	6.5	7.3	7.6	2.8	3.2	1.1	27.5	2319.8%
Total	**0.4**	**0.1**	**0.0**	**0.0**	**0.0**	**5.2**	**5.2**	**5.2**	**0.0**	**0.0**	**0.5**	**15.5**	**2781.4%**
Network Operating Costs													
Inspections and maintenance	4.7	4.2	4.0	3.5	3.6	4.0	3.8	4.3	4.0	4.2	20.1	20.4	1.4%
Fault repairs and restoration	12.2	18.4	18.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	77.5	70.3	-9.3%
Tree cutting	4.6	6.1	5.5	4.8	4.0	3.6	3.5	3.5	3.4	3.3	25.0	17.3	-30.8%
Other Network costs	0.0	-1.6	-1.0	-0.4	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-3.7	-3.5	N/A
Total	**21.6**	**27.1**	**27.2**	**22.0**	**21.0**	**21.0**	**20.7**	**21.1**	**20.8**	**20.9**	**118.9**	**104.4**	**-12.1%**
RPEs				0.4	0.6	0.7	0.8	1.0	1.1	1.3	0.9	4.8	
Total (Including RPEs)	**21.6**	**27.1**	**27.2**	**22.3**	**21.6**	**21.7**	**21.5**	**22.1**	**21.9**	**22.1**	**119.8**	**109.3**	**-8.8%**
Indirect Costs													
Engineering Indirects	19.7	19.8	19.5	19.4	20.0	19.9	19.9	20.0	20.0	20.2	98.4	100.0	1.6%
Network/Investment Support	8.6	8.5	8.3	8.7	8.9	8.9	9.0	9.0	9.0	9.0	43.0	44.9	4.4%
Business Support	18.9	18.6	18.1	18.9	19.3	19.4	19.4	19.6	19.7	19.8	93.8	97.9	4.4%
Non-operational capex	3.9	5.3	3.9	5.2	6.3	6.9	5.5	5.0	5.6	5.9	24.6	28.9	17.5%
Total	**51.1**	**52.2**	**49.8**	**52.2**	**54.5**	**55.1**	**53.8**	**53.6**	**54.3**	**54.9**	**259.8**	**271.7**	**4.6%**
RPEs				0.8	1.5	1.8	2.1	2.5	2.9	3.3	2.3	12.6	
Total (Including RPEs)	**51.1**	**52.2**	**49.8**	**53.0**	**56.0**	**56.9**	**55.9**	**56.1**	**57.2**	**58.2**	**262.1**	**284.3**	**8.5%**
Total	**115.1**	**121.0**	**131.9**	**126.7**	**128.5**	**146.1**	**149.4**	**154.7**	**157.5**	**151.6**	**623.1**	**759.4**	**21.9%**
Total RPEs				2.0	3.4	4.8	5.9	7.1	8.3	9.2	5.5	35.3	
Total (Including RPEs)	**115.1**	**121.0**	**131.9**	**128.7**	**131.9**	**150.9**	**155.3**	**161.9**	**165.8**	**160.8**	**628.5**	**794.6**	**26.4%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	28.7	23.7	31.8	22.3	26.8	26.1	25.4	25.3	25.3	25.3	133.4	127.5	-4.4%
Diversions	2.9	4.8	2.5	1.0	0.9	0.9	0.6	0.5	0.5	0.5	12.1	3.0	-75.1%
General reinforcement - P2/6	11.4	7.5	14.4	13.1	10.9	10.3	13.9	16.9	9.5	10.7	57.3	61.2	6.9%
General reinforcement - Fault Levels	0.0	0.0	0.0	0.4	1.5	2.2	3.2	1.4	1.1	0.0	1.9	8.0	330.1%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**43.1**	**36.0**	**48.7**	**36.8**	**40.1**	**39.6**	**43.1**	**44.1**	**36.4**	**36.6**	**204.7**	**199.8**	**-2.4%**
Customer Contributions													
Customer specific - Demand	34.5	30.0	33.4	27.4	29.5	28.9	28.2	28.0	28.0	28.0	154.8	141.1	-8.9%
Total Load related (Net)	**8.6**	**6.0**	**15.3**	**9.4**	**10.6**	**10.7**	**14.9**	**16.1**	**8.4**	**8.6**	**49.9**	**58.7**	**17.7%**
Non Load related investment													
Asset replacement	27.7	30.4	33.7	35.8	35.0	46.9	48.2	53.8	66.8	65.2	162.5	281.0	72.9%
Quality of supply (IIS)	3.8	3.3	3.5	2.6	1.9	1.3	0.0	0.0	0.0	0.0	15.1	1.3	-91.3%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	2.1	3.2	2.5	5.0	0.5	0.0	13.4	N/A
Operational IT and telecoms	0.2	0.0	0.0	0.5	1.1	1.6	1.2	0.2	0.3	0.2	1.8	3.5	96.5%
Environmental	0.5	0.2	0.3	1.9	2.2	0.3	0.3	0.3	0.3	0.3	5.1	1.4	-73.6%
Legal & safety	1.2	1.6	2.1	2.4	2.3	2.0	2.0	2.0	1.6	1.1	9.5	8.6	-9.7%
Total Non Load related	**33.3**	**35.5**	**39.6**	**43.1**	**42.4**	**54.1**	**54.8**	**58.8**	**74.0**	**67.3**	**194.0**	**309.1**	**59.3%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	2.1	1.2	0.5	5.0	0.5	0.0	9.4	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	0.0	0.0	0.0	4.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	1.1	1.0	0.0	0.0	0.0	0.0	2.1	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	0.9	1.3	0.9	0.9	0.9	0.5	0.0	2.2	3.2	47.7%
Environmental													
Visual Amenity	0.0	0.0	0.0	1.6	1.9	0.0	0.0	0.0	0.0	0.0	3.5	0.0	-100.0%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	4.5	400.0%

CE (NEDL) - August FBPQ Narrative

1.32. The draft forecast represents good value for money, enabling us to meet our duties and maintain the necessary pace of asset replacement while recognising the need to contain costs during a period of economic difficulty. The total increase of 26.4% on DPCR4 levels seeks to maintain our current performance standards and reflects the same prudent approach towards asset risk while assuming there is no fundamental change in the role of a distribution business.

1.33. Feedback from customers indicates a significant sensitivity to price rises, with about half of those we surveyed demonstrating no willingness to pay for additional benefits. Those who are willing to pay for improvements are looking for improvements in their own local performance rather than improvements in underlying risk or in other customers' quality of supply. Accordingly, our plans prioritise cost containment ahead of discretionary investment.

1.34. Approximately 50% of our technically skilled workforce (internal and external) is due to retire in the 10-year period from 2010. The training and development costs for these replacement staff of ca. £10m are not included in the accompanying tables.

Load related investment

1.35. For the DPCR5 period we are forecasting an increase in total net expenditure of 17.7% relative to the DPCR4 period. This is primarily caused by a general increase in reinforcement expenditure, and an increase in fault level asset replacement in line with the tightening of statute and policy in this area. This section of our draft plan is being thoroughly reviewed with the benefit of the latest available data prior to the final submission of our detailed business plans.

1.36. The increase in investment required to reinforce the network to accommodate greater volumes of distributed generation reflects the upturn in work volumes required to meet the UK's 2020 carbon reduction targets.

Non load related investment

1.37. The peak of the asset replacement cycle is expected to occur between 2015 and 2020. The 72.9% increase in asset replacement reflects the rise in unit prices seen in the DPCR4 period and the increase in future volumes but we have not assumed that input price increases will continue significantly to exceed increases in RPI. Incremental quality of supply and environmental benefits will be pursued to counter any general deterioration or localised pockets of underperformance predominantly through targeting of core asset replacement activity. Costs totalling £13.3m relating to city-centre reinforcement, flood protection and new communication circuits have been included although it is not our view that such costs should be incurred. They are included because the actions of other stakeholders may make them unavoidable.

Electricity distribution price control review
Policy paper - supplementary appendices 5 December 2008

CE (YEDL) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
CE YEDL	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	67.8	52.5	63.5	55.0	58.9	70.2	73.1	68.8	69.2	66.7	297.8	347.8	16.8%
Customer contributions	53.6	54.7	52.6	48.0	48.8	51.3	50.4	50.2	50.0	50.0	257.6	251.9	-2.2%
Load related (net)	14.3	-2.2	10.9	7.0	10.1	18.8	22.7	18.6	19.1	16.7	40.1	96.0	139.2%
Non load related	58.3	50.0	45.6	59.1	69.1	79.0	71.7	79.7	85.3	89.2	282.0	404.9	43.6%
Total	**72.6**	**47.8**	**56.5**	**66.1**	**79.2**	**97.8**	**94.4**	**98.3**	**104.4**	**105.9**	**322.2**	**500.9**	**55.5%**
RPEs (net)				1.1	2.1	3.2	3.7	4.5	5.8	6.7	3.2	24.1	
Total (Including RPEs)	**72.6**	**47.8**	**56.5**	**67.2**	**81.3**	**101.0**	**98.1**	**102.9**	**110.3**	**112.6**	**325.3**	**524.9**	**61.3%**
Distributed Generation													
Customer specific - Generation	1.4	1.1	1.5	0.3	0.5	3.4	3.8	4.1	9.5	9.7	4.8	30.5	540.7%
Customer contributions	0.0	1.0	1.5	0.3	0.5	2.9	3.3	3.6	3.8	4.1	3.3	17.6	442.0%
Total	**1.4**	**0.1**	**0.0**	**0.0**	**0.0**	**0.5**	**0.5**	**0.5**	**5.7**	**5.7**	**1.5**	**12.9**	**753.6%**
Network Operating Costs													
Inspections and maintenance	4.6	5.9	5.7	5.1	5.3	5.9	5.8	5.6	5.6	5.4	26.7	28.3	6.1%
Fault repairs and restoration	15.2	27.3	31.9	27.0	25.5	25.5	25.5	25.5	25.5	25.5	126.8	127.4	0.5%
Tree cutting	6.0	8.1	6.8	5.5	6.6	5.7	5.1	4.8	4.7	4.6	33.0	24.9	-24.5%
Other Network costs	0.0	-1.9	-1.0	-2.3	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-7.3	-10.5	N/A
Total	**25.8**	**39.4**	**43.4**	**35.3**	**35.3**	**35.0**	**34.3**	**33.8**	**33.7**	**33.4**	**179.2**	**170.1**	**-5.1%**
RPEs				0.6	0.9	1.1	1.3	1.6	1.8	2.0	1.5	7.8	
Total (Including RPEs)	**25.8**	**39.4**	**43.4**	**35.9**	**36.2**	**36.1**	**35.6**	**35.3**	**35.5**	**35.4**	**180.7**	**178.0**	**-1.5%**
Indirect Costs													
Engineering Indirects	23.2	21.6	22.5	23.0	23.7	23.7	23.9	24.0	24.0	24.0	114.0	119.6	4.9%
Network/Investment Support	9.8	9.7	10.1	10.1	10.5	10.3	10.4	10.5	10.5	10.5	50.2	52.2	4.0%
Business Support	23.7	20.8	20.3	21.0	21.8	21.7	21.8	21.8	21.9	22.0	107.6	109.2	1.5%
Non-operational capex	2.9	4.5	4.1	3.9	4.0	5.0	5.3	4.5	4.1	4.0	19.4	22.9	18.0%
Total	**59.6**	**56.6**	**57.0**	**58.0**	**60.0**	**60.7**	**61.4**	**60.8**	**60.5**	**60.5**	**291.2**	**303.9**	**4.4%**
RPEs				0.9	1.6	2.0	2.4	2.8	3.2	3.7	2.5	14.1	
Total (Including RPEs)	**59.6**	**56.6**	**57.0**	**58.9**	**61.6**	**62.7**	**63.8**	**63.6**	**63.7**	**64.2**	**293.7**	**318.0**	**8.2%**
Total	**159.4**	**143.9**	**156.9**	**159.4**	**174.5**	**194.0**	**190.6**	**193.4**	**204.3**	**205.4**	**794.1**	**987.8**	**24.4%**
Total RPEs				2.6	4.7	6.4	7.5	8.9	10.8	12.4	7.2	46.0	
Total (Including RPEs)	**159.4**	**143.9**	**156.9**	**162.0**	**179.2**	**200.4**	**198.1**	**202.3**	**215.1**	**217.8**	**801.3**	**1033.7**	**29.0%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	50.3	39.6	43.9	43.9	46.6	50.0	48.9	48.6	48.5	48.5	224.4	244.4	8.9%
Diversions	1.7	2.4	7.9	2.7	3.6	2.6	2.5	2.5	2.5	2.5	18.4	12.6	-31.1%
General reinforcement - P2/6	15.8	10.5	10.7	8.0	7.3	14.4	19.7	16.1	14.1	12.6	52.2	76.9	47.2%
General reinforcement - Fault Levels	0.0	0.0	1.0	0.4	1.4	3.2	2.0	1.6	4.1	3.1	2.8	13.9	393.7%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**67.8**	**52.5**	**63.5**	**55.0**	**58.9**	**70.2**	**73.1**	**68.8**	**69.2**	**66.7**	**297.8**	**347.8**	**16.8%**
Customer Contributions													
Customer specific - Demand	53.6	54.7	52.6	48.0	48.8	51.3	50.4	50.2	50.0	50.0	257.6	251.9	-2.2%
Total Load related (Net)	**14.3**	**-2.2**	**10.9**	**7.0**	**10.1**	**18.8**	**22.7**	**18.6**	**19.1**	**16.7**	**40.1**	**96.0**	**139.2%**
Non Load related investment													
Asset replacement	47.2	43.4	36.8	46.4	59.1	66.5	61.4	66.0	72.9	74.6	233.0	341.2	46.5%
Quality of supply (IIS)	3.0	3.1	3.3	5.6	2.8	1.9	0.0	0.0	0.0	0.0	17.8	1.9	-89.2%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Major system risks	0.0	0.0	0.0	0.6	0.4	2.9	3.3	8.4	7.5	10.4	0.9	32.6	3380.4%
Operational IT and telecoms	2.9	0.1	0.5	0.9	1.1	2.6	1.9	0.2	0.3	0.2	5.5	5.2	-5.1%
Environmental	1.8	0.5	0.5	0.9	0.9	0.4	0.4	0.4	0.4	0.4	4.6	2.0	-56.3%
Legal & safety	3.3	2.8	4.5	4.8	4.8	4.6	4.7	4.7	4.2	3.6	20.3	21.9	8.0%
Total Non Load related	**58.3**	**50.0**	**45.6**	**59.1**	**69.1**	**79.0**	**71.7**	**79.7**	**85.3**	**89.2**	**282.0**	**404.9**	**43.6%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.6	0.4	1.9	2.5	6.4	2.5	6.4	0.9	19.8	2015.0%
HILP	0.0	0.0	0.0	0.0	0.0	1.0	0.8	2.0	5.0	4.0	0.0	12.8	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	2.1	1.7	0.0	0.0	0.0	0.0	3.8	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	1.2	2.4	2.4	2.4	2.4	1.9	1.4	3.7	10.6	190.1%
Environmental													
Visual Amenity	0.0	0.0	0.0	0.4	0.5	0.0	0.0	0.0	0.0	0.0	0.9	0.0	-100.0%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	4.5	400.0%

CE (YEDL) - August FBPQ Narrative

1.38. The draft forecast represents good value for money, enabling us to meet our duties and maintain the necessary pace of asset replacement while recognising the need to contain costs during a period of economic difficulty. The total increase of 29.0% on DPCR4 levels seeks to maintain our current performance standards and reflects the same prudent approach towards asset risk while assuming there is no fundamental change in the role of a distribution business.

1.39. Feedback from customers indicates a significant sensitivity to price rises, with about half of those we surveyed demonstrating no willingness to pay for additional benefits. Those who are willing to pay for improvements are looking for improvements in their own local performance rather than improvements in underlying risk or in other customers' quality of supply. Accordingly, our plans prioritise cost containment ahead of discretionary investment.

1.40. Approximately 50% of our technically skilled workforce (internal and external) is due to retire in the 10-year period from 2010. The training and development costs for these replacement staff of ca. £15m are not included in the accompanying tables.

Load related investment

1.41. For the DPCR5 period we are forecasting an increase in total net expenditure of 139.2% relative to the DPCR4 period. This is primarily caused by a general increase in connections and reinforcement expenditure, and an increase in fault level asset replacement in line with the tightening of statute and policy in this area. This section of our draft plan is being thoroughly reviewed with the benefit of the latest available data prior to the final submission of our detailed business plans.

1.42. The increase in investment required to reinforce the network to accommodate greater volumes of distributed generation reflects the upturn in work volumes required to meet the UK's 2020 carbon reduction targets.

Non load related investment

1.43. The peak of the asset replacement cycle is expected to occur between 2015 and 2020. The 46.5% increase in asset replacement reflects the rise in unit prices seen in the DPCR4 period and the increase in future volumes but we have not assumed that input price increases will continue significantly to exceed increases in RPI. Incremental quality of supply and environmental benefits will be pursued to counter any general deterioration or localised pockets of underperformance predominantly through targeting of core asset replacement activity. Costs totalling £32.8m relating to city-centre reinforcement, flood protection and new communication circuits have been included although it is not our view that such costs should be incurred. They are included because the actions of other stakeholders may make them unavoidable.

WPD (South Wales) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
WPD Swales	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	24.0	25.2	25.6	21.7	20.2	21.2	21.3	20.6	20.0	21.2	116.7	104.3	-10.6%
Customer contributions	16.3	20.9	24.8	17.2	14.0	15.3	15.4	14.9	14.9	14.9	93.2	75.4	-19.1%
Load related (net)	7.7	4.3	0.8	4.5	6.2	5.9	5.9	5.7	5.1	6.3	23.5	28.9	23.0%
Non load related	17.2	25.4	31.5	26.7	21.6	44.2	47.3	48.1	50.8	49.3	122.4	239.8	96.0%
Total	**24.9**	**29.7**	**32.3**	**31.2**	**27.8**	**50.1**	**53.2**	**53.8**	**55.9**	**55.6**	**145.9**	**268.7**	**84.2%**
RPEs (net)				0.5	0.8	2.3	3.3	4.2	5.2	6.1	1.3	21.1	
Total (Including RPEs)	**24.9**	**29.7**	**32.3**	**31.7**	**28.6**	**52.4**	**56.5**	**58.0**	**61.1**	**61.7**	**147.2**	**289.8**	**96.9%**
Distributed Generation													
Customer specific - Generation	1.7	0.3	0.6	1.1	1.8	5.1	5.2	5.5	5.4	5.6	5.5	26.8	387.3%
Customer contributions	2.1	0.3	0.6	1.0	1.7	4.8	4.8	5.0	5.0	5.1	5.7	24.7	333.3%
Total	**-0.4**	**0.0**	**0.0**	**0.1**	**0.1**	**0.3**	**0.4**	**0.5**	**0.4**	**0.5**	**-0.2**	**2.1**	**N/A**
Network Operating Costs													
Inspections and maintenance	6.2	4.6	5.3	5.0	5.0	5.0	5.0	5.0	5.0	5.0	26.1	25.0	-4.2%
Fault repairs and restoration	9.1	9.3	9.0	9.3	9.3	9.3	9.3	9.3	9.3	9.3	46.0	46.5	1.1%
Tree cutting	3.8	3.0	4.2	4.3	4.6	5.6	5.6	5.6	5.6	5.6	19.9	28.0	40.7%
Other Network costs	0.2	0.3	0.1	0.3	0.4	0.4	0.5	0.6	0.6	0.7	1.3	2.8	115.4%
Total	**19.3**	**17.2**	**18.6**	**18.9**	**19.3**	**20.3**	**20.4**	**20.5**	**20.5**	**20.6**	**93.3**	**102.3**	**9.6%**
RPEs				0.1	0.3	0.4	0.6	0.7	0.9	1.0	0.4	3.6	
Total (Including RPEs)	**19.3**	**17.2**	**18.6**	**19.0**	**19.6**	**20.7**	**21.0**	**21.2**	**21.4**	**21.6**	**93.7**	**105.9**	**13.0%**
Indirect Costs													
Engineering Indirects	13.3	13.4	13.5	13.6	13.6	14.0	14.8	15.1	15.1	15.2	67.4	74.2	10.1%
Network/Investment Support	10.4	8.8	8.9	8.9	9.2	9.2	9.5	9.5	9.6	9.5	46.2	47.3	2.4%
Business Support	17.3	17.1	17.4	17.4	17.4	17.4	17.6	17.6	17.6	17.6	86.6	87.8	1.4%
Non-operational capex	0.0	0.0	2.5	2.7	3.5	5.8	4.1	3.1	3.1	4.6	8.7	20.7	137.9%
Total	**41.0**	**39.3**	**42.3**	**42.6**	**43.7**	**46.4**	**46.0**	**45.3**	**45.4**	**46.9**	**208.9**	**230.0**	**10.1%**
RPEs				0.3	0.5	1.0	1.3	1.5	2.0	2.4	0.8	8.2	
Total (Including RPEs)	**41.0**	**39.3**	**42.3**	**42.9**	**44.2**	**47.4**	**47.3**	**46.8**	**47.4**	**49.3**	**209.7**	**238.2**	**13.6%**
Total	**84.8**	**86.2**	**93.2**	**92.8**	**90.9**	**117.1**	**120.0**	**120.1**	**122.2**	**123.6**	**447.9**	**603.1**	**34.7%**
Total RPEs				0.9	1.6	3.7	5.2	6.4	8.1	9.5	2.5	32.9	
Total (Including RPEs)	**84.8**	**86.2**	**93.2**	**93.7**	**92.5**	**120.8**	**125.2**	**126.5**	**130.3**	**133.1**	**450.4**	**636.0**	**41.2%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	17.6	18.1	20.6	15.4	12.4	13.5	13.6	13.3	13.3	13.3	84.1	67.0	-20.3%
Diversions	1.5	1.4	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	7.0	7.0	0.0%
General reinforcement - P2/6	4.9	5.7	3.7	4.9	6.4	6.3	5.6	5.9	5.3	6.5	25.6	29.6	15.6%
General reinforcement - Fault Levels	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.7	N/A
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**24.0**	**25.2**	**25.6**	**21.7**	**20.2**	**21.2**	**21.3**	**20.6**	**20.0**	**21.2**	**116.7**	**104.3**	**-10.6%**
Customer Contributions													
Customer specific - Demand	16.3	20.9	24.8	17.2	14.0	15.3	15.4	14.9	14.9	14.9	93.2	75.4	-19.1%
Total Load related (Net)	**7.7**	**4.3**	**0.8**	**4.5**	**6.2**	**5.9**	**5.9**	**5.7**	**5.1**	**6.3**	**23.5**	**28.9**	**23.0%**
Non Load related investment													
Asset replacement	12.9	20.5	24.0	15.5	15.5	28.0	30.4	33.1	35.2	35.7	88.4	162.4	83.7%
Quality of supply (IIS)	2.9	4.0	3.6	6.0	2.5	2.2	2.2	2.2	2.2	0.3	19.0	9.1	-51.9%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	0.0	9.0	N/A
Major system risks	0.0	0.0	0.0	0.4	0.4	1.4	1.9	1.9	1.9	1.5	0.8	8.6	975.0%
Operational IT and telecoms	1.4	0.9	3.4	3.6	0.8	2.6	2.7	0.8	0.8	2.7	10.1	9.5	-5.3%
Environmental	0.0	0.0	0.0	0.0	0.0	4.1	4.2	4.3	4.9	4.9	0.0	22.4	N/A
Legal & safety	0.0	0.0	0.5	1.3	2.4	4.1	4.1	4.0	4.0	2.5	4.1	18.8	356.7%
Total Non Load related	**17.2**	**25.4**	**31.5**	**26.7**	**21.6**	**44.2**	**47.3**	**48.1**	**50.8**	**49.3**	**122.4**	**239.8**	**96.0%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.4	0.4	1.4	1.9	1.9	1.9	1.5	0.8	8.6	975.0%
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	1.5	0.0	0.0	0.0	0.0	0.0	1.5	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	0.5	0.8	0.9	0.9	0.9	0.9	0.9	1.3	4.5	260.1%
Environmental													
Visual Amenity	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.0	1.0	N/A
Technical Losses				0.0	0.0	3.6	3.6	3.6	3.6	3.6	0.0	18.0	N/A
Tree cutting													
ETR-132			0.3	0.4	0.4	1.1	1.1	1.1	1.1	1.1	1.1	5.5	400.0%

WPD (South Wales) - August FBPQ Narrative

1.44. WPD (South Wales) is a customer focused business that has delivered the highest levels of customer service throughout DPCR4. WPD will continue to focus on delivering customer service excellence during DPCR5. WPD (South Wales) has a track record of delivering the level of network investment agreed with Ofgem for each price control period. WPD (South Wales) is on target to deliver the agreed network investment for DPCR4, and is on target to outperform the DPCR4 quality of supply targets agreed with Ofgem.

1.45. The majority of craft work undertaken within WPD is carried out by WPD's own staff rather than contractors. To date, during DPCR4, WPD, has recruited 131 youth and 84 adult craft apprentices. During DPCR4, WPD has not experienced craft resource availability difficulties. WPD propose to continue with the current approach during DPCR5 and beyond. In order to deliver the increased level of network investment it is planned to increase the recruitment rate for both youth and adult craft apprentices.

1.46. The initial business plan, i.e. August 2008, for WPD (South Wales) was compiled after a stakeholder consultation process had been completed. The output from the stakeholder consultation was an aggregated view of stakeholders' priorities.

1.47. Load Related Network Investment is driven by economic activity as this influences the number of new connections made to our distribution network and the extent of changes in the electricity requirements of existing customers.

1.48. The most significant element of Non Load Related Network Investment is the condition based replacement of assets that have reached the end of their useful life. The forecast increase during DPCR5 is reflective of an aging asset base. The forecast average annual asset replacement investment during DPCR5 equates to 1% of the Modern Equivalent Asset Value of the asset base. The other elements of Non Load Related Network Investment are driven by a range of factors. Our stakeholders have indicated their support for a range of initiatives, such as improving the quality of supply experienced by 'worst served customers' and the use of low loss transformers.

1.49. The forecast level of investment to connect Distributed Generation during DPCR5 reflects an expectation that more distributed generation will be developed in order to achieve government targets for CO_2 reduction.

1.50. Network operating costs and indirect costs are both forecast to increase during DPCR5. This increase in network operating costs is predominantly associated with additional tree cutting obligations. The increase in indirect costs is driven by the need to refresh and upgrade IT systems and hardware and the increase in network investment.

WPD (South West) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
WPD Swest	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	33.9	32.8	31.1	29.6	24.7	26.1	29.1	29.6	27.5	27.2	152.1	139.5	-8.3%
Customer contributions	21.4	23.9	27.8	22.2	18.7	20.4	21.2	21.2	21.2	21.2	114.0	105.2	-7.7%
Load related (net)	12.5	8.9	3.3	7.4	6.0	5.7	7.9	8.4	6.3	6.0	38.1	34.3	-10.0%
Non load related	31.0	38.9	43.3	43.5	44.5	62.1	67.1	68.2	71.5	71.1	201.2	340.1	69.0%
Total	**43.5**	**47.8**	**46.6**	**50.9**	**50.5**	**67.8**	**75.0**	**76.6**	**77.8**	**77.1**	**239.3**	**374.4**	**56.4%**
RPEs (net)				0.8	1.5	3.1	4.6	6.0	7.3	8.5	2.3	29.5	
Total (Including RPEs)	**43.5**	**47.8**	**46.6**	**51.7**	**52.0**	**70.9**	**79.6**	**82.6**	**85.1**	**85.6**	**241.6**	**403.9**	**67.1%**
Distributed Generation													
Customer specific - Generation	0.5	0.1	0.3	1.0	1.6	6.5	2.1	2.4	2.3	2.6	3.5	15.9	354.3%
Customer contributions	0.5	0.1	0.3	0.9	1.5	6.2	1.9	2.1	2.1	2.2	3.3	14.5	339.4%
Total	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.3**	**0.2**	**0.3**	**0.2**	**0.4**	**0.2**	**1.4**	**600.0%**
Network Operating Costs													
Inspections and maintenance	6.5	6.7	7.1	6.3	6.3	6.3	6.3	6.3	6.3	6.3	32.9	31.5	-4.3%
Fault repairs and restoration	14.7	14.3	14.4	14.6	14.6	14.6	14.6	14.6	14.6	14.6	72.6	73.0	0.6%
Tree cutting	4.8	5.2	5.3	6.0	7.4	8.6	8.6	8.6	8.6	8.6	28.7	43.0	49.8%
Other Network costs	0.7	0.6	0.4	0.6	0.7	0.7	0.7	0.8	0.8	0.9	3.0	3.9	28.3%
Total	**26.7**	**26.8**	**27.2**	**27.5**	**29.0**	**30.2**	**30.2**	**30.3**	**30.3**	**30.4**	**137.2**	**151.4**	**10.3%**
RPEs				0.2	0.4	0.6	0.9	1.1	1.3	1.5	0.6	5.4	
Total (Including RPEs)	**26.7**	**26.8**	**27.2**	**27.7**	**29.4**	**30.8**	**31.1**	**31.4**	**31.6**	**31.9**	**137.8**	**156.8**	**13.8%**
Indirect Costs													
Engineering Indirects	19.5	18.5	18.7	18.8	18.8	20.0	20.7	21.2	21.0	20.9	94.3	103.8	10.1%
Network/Investment Support	12.3	10.8	10.8	10.8	11.0	11.2	11.4	11.4	11.4	11.4	55.7	56.8	2.0%
Business Support	20.2	18.9	19.0	19.0	19.0	19.0	19.2	19.2	19.2	19.2	96.1	95.8	-0.3%
Non-operational capex	0.0	0.0	14.5	6.4	5.2	12.4	11.7	9.7	8.2	10.5	26.1	52.6	101.3%
Total	**52.0**	**48.2**	**63.0**	**55.0**	**54.0**	**62.6**	**63.0**	**61.5**	**59.8**	**62.0**	**272.2**	**309.0**	**13.5%**
RPEs				0.3	0.9	1.3	1.7	2.2	2.6	3.1	1.2	10.9	
Total (Including RPEs)	**52.0**	**48.2**	**63.0**	**55.3**	**54.9**	**63.9**	**64.7**	**63.7**	**62.4**	**65.1**	**273.4**	**319.9**	**17.0%**
Total	**122.2**	**122.8**	**136.8**	**133.5**	**133.6**	**160.9**	**168.5**	**168.7**	**168.1**	**169.9**	**649.0**	**836.1**	**28.8%**
Total RPEs				1.3	2.8	5.0	7.2	9.3	11.2	13.1	4.1	45.8	
Total (Including RPEs)	**122.2**	**122.8**	**136.8**	**134.8**	**136.4**	**165.9**	**175.7**	**178.0**	**179.3**	**183.0**	**653.1**	**881.9**	**35.0%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	22.8	21.8	23.5	19.6	16.5	18.0	18.7	18.7	18.7	18.7	104.2	92.8	-10.9%
Diversions	2.7	2.2	1.9	2.3	2.3	2.3	2.3	2.3	2.3	2.3	11.4	11.5	0.9%
General reinforcement - P2/6	8.4	8.8	5.7	7.7	5.9	5.8	8.1	8.6	6.5	6.2	36.5	35.2	-3.6%
General reinforcement - Fault Levels	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**33.9**	**32.8**	**31.1**	**29.6**	**24.7**	**26.1**	**29.1**	**29.6**	**27.5**	**27.2**	**152.1**	**139.5**	**-8.3%**
Customer Contributions													
Customer specific - Demand	21.4	23.9	27.8	22.2	18.7	20.4	21.2	21.2	21.2	21.2	114.0	105.2	-7.7%
Total Load related (Net)	**12.5**	**8.9**	**3.3**	**7.4**	**6.0**	**5.7**	**7.9**	**8.4**	**6.3**	**6.0**	**38.1**	**34.3**	**-10.0%**
Non Load related investment													
Asset replacement	26.5	34.4	37.8	33.6	33.6	40.8	44.4	47.8	51.2	51.5	165.9	235.7	42.1%
Quality of supply (IIS)	3.1	2.6	2.1	2.1	3.1	0.6	0.6	0.6	0.6	0.2	13.0	2.6	-79.9%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	2.9	2.9	2.9	2.9	2.9	0.0	14.6	N/A
Major system risks	0.0	0.0	0.0	0.4	0.5	1.4	1.4	1.4	1.4	1.4	0.9	7.0	677.8%
Operational IT and telecoms	1.4	1.9	3.4	3.6	0.8	1.4	2.8	0.8	0.8	2.7	11.1	8.4	-24.2%
Environmental	0.0	0.0	0.0	0.2	0.0	7.0	6.8	6.5	6.5	5.3	0.2	32.2	15985.0%
Legal & safety	0.0	0.0	0.0	3.6	6.5	8.0	8.2	8.2	8.1	7.2	10.1	39.6	290.6%
Total Non Load related	**31.0**	**38.9**	**43.3**	**43.5**	**44.5**	**62.1**	**67.1**	**68.2**	**71.5**	**71.1**	**201.2**	**340.1**	**69.0%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.4	0.5	1.4	1.4	1.4	1.4	1.4	0.9	7.0	677.8%
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.1	0.0	0.3	0.2	0.0	0.0	0.0	0.1	0.4	720.0%
Legal & safety													
ESQCR	0.0	0.0	0.0	2.5	4.2	4.8	4.9	4.9	4.9	4.9	6.7	24.3	260.4%
Environmental													
Visual Amenity	0.0	0.0	0.0	0.2	0.0	0.3	0.3	0.3	0.3	0.3	0.2	1.5	650.0%
Technical Losses				0.0	0.0	4.3	4.3	4.3	4.3	4.3	0.0	21.5	N/A
Tree cutting													
ETR-132			0.0	0.3	0.9	1.5	1.5	1.5	1.5	1.5	1.2	7.5	525.0%

WPD (South West) - August FBPQ Narrative

1.51. WPD (South West) is a customer focused business that has delivered the highest levels of customer service throughout DPCR4. WPD will continue to focus on delivering customer service excellence during DPCR5. WPD (South West) has a track record of delivering the level of network investment agreed with Ofgem for each price control period. WPD (South West) is on target to deliver the agreed network investment for DPCR4, and is on target to outperform the DPCR4 quality of supply targets agreed with Ofgem.

1.52. The majority of craft work undertaken within WPD is carried out by WPD's own staff rather than contractors. To date, during DPCR4, WPD, has recruited 131 youth and 84 adult craft apprentices. During DPCR4, WPD has not experienced craft resource availability difficulties. WPD propose to continue with the current approach during DPCR5 and beyond. In order to deliver the increased level of network investment it is planned to increase the recruitment rate for both youth and adult craft apprentices.

1.53. The initial business plan, i.e. August 2008, for WPD (South West) was compiled after a stakeholder consultation process had been completed. The output from the stakeholder consultation was an aggregated view of stakeholders' priorities.

1.54. Load Related Network Investment is driven by economic activity as this influences the number of new connections made to our distribution network and the extent of changes in the electricity requirements of existing customers.

1.55. The most significant element of Non Load Related Network Investment is the condition based replacement of assets that have reached the end of their useful life. The forecast increase during DPCR5 is reflective of an aging asset base. The forecast average annual asset replacement investment during DPCR5 equates to 1% of the Modern Equivalent Asset Value of the asset base. The other elements of Non Load Related Network Investment are driven by a range of factors. Our stakeholders have indicated their support for a range of initiatives, such as improving the quality of supply experienced by 'worst served customers' and the use of low loss transformers.

1.56. The forecast level of investment to connect Distributed Generation during DPCR5 reflects an expectation that more distributed generation will be developed in order to achieve government targets for CO_2 reduction.

1.57. Network operating costs and indirect costs are both forecast to increase during DPCR5. This increase in network operating costs is predominantly associated with additional tree cutting obligations. The increase in indirect costs is driven by the need to refresh and upgrade IT systems and hardware and the increase in network investment.

EDFE (LPN) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
EDFE LPN	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	48.8	51.2	80.6	86.3	101.3	115.5	123.8	123.0	112.0	108.9	368.2	583.2	58.4%
Customer contributions	37.5	51.7	60.4	64.4	65.0	67.2	69.6	72.6	72.2	62.4	279.0	343.9	23.3%
Load related (net)	11.3	-0.5	20.2	21.9	36.2	48.3	54.2	50.4	39.8	46.5	89.2	239.3	168.4%
Non load related	52.5	70.2	49.7	49.0	44.5	61.1	91.6	126.1	130.5	104.7	265.9	514.0	93.3%
Total	**63.8**	**69.7**	**69.9**	**70.9**	**80.7**	**109.4**	**145.8**	**176.6**	**170.3**	**151.2**	**355.1**	**753.3**	**112.2%**
RPEs (net)				1.3	2.6	4.9	8.7	12.6	14.6	15.7	3.9	56.5	
Total (Including RPEs)	**63.8**	**69.7**	**69.9**	**72.2**	**83.3**	**114.3**	**154.5**	**189.2**	**184.9**	**166.9**	**359.0**	**809.8**	**125.6%**
Distributed Generation													
Customer specific - Generation	0.2	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.8	246.6%
Customer contributions	0.3	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.4	0.7	69.8%
Total	**-0.1**	**-0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-0.2**	**0.0**	**N/A**
Network Operating Costs													
Inspections and maintenance	10.8	10.4	9.5	10.5	10.2	10.2	10.1	10.1	10.1	10.1	51.4	50.6	-1.6%
Fault repairs and restoration	18.9	27.8	26.5	26.1	26.3	26.5	26.6	26.8	26.9	27.1	125.6	133.9	6.6%
Tree cutting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Other Network costs	0.4	-1.5	-2.9	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-2.0	-8.0	-10.0	N/A
Total	**30.1**	**36.7**	**33.1**	**34.6**	**34.5**	**34.7**	**34.7**	**34.9**	**35.0**	**35.2**	**169.0**	**174.5**	**3.3%**
RPEs				0.5	1.2	1.9	2.7	3.4	4.2	5.1	1.7	17.3	
Total (Including RPEs)	**30.1**	**36.7**	**33.1**	**35.1**	**35.7**	**36.6**	**37.4**	**38.3**	**39.2**	**40.3**	**170.7**	**191.8**	**12.4%**
Indirect Costs													
Engineering Indirects	16.8	20.8	25.9	28.7	28.1	28.4	29.5	32.1	35.4	36.5	120.3	161.9	34.6%
Network/Investment Support	11.8	13.6	13.1	15.6	17.0	17.7	18.0	18.1	18.0	17.8	71.1	89.6	26.0%
Business Support	28.2	28.0	30.8	32.6	32.0	31.6	32.1	32.0	31.5	30.9	151.6	158.1	4.3%
Non-operational capex	4.3	7.8	7.6	8.2	7.6	7.9	8.2	7.2	7.5	8.7	35.5	39.5	11.2%
Total	**61.1**	**70.2**	**77.4**	**85.1**	**84.7**	**85.6**	**87.8**	**89.4**	**92.4**	**93.9**	**378.5**	**449.1**	**18.6%**
RPEs				1.3	2.4	3.7	5.0	6.6	8.6	10.3	3.7	34.2	
Total (Including RPEs)	**61.1**	**70.2**	**77.4**	**86.4**	**87.1**	**89.3**	**92.8**	**96.0**	**101.0**	**104.2**	**382.2**	**483.3**	**26.4%**
Total	**155.0**	**176.5**	**180.4**	**190.6**	**199.9**	**229.7**	**268.3**	**300.9**	**297.8**	**280.3**	**902.4**	**1377.0**	**52.6%**
Total RPEs				3.1	6.2	10.5	16.4	22.6	27.4	31.1	9.3	108.0	
Total (Including RPEs)	**155.0**	**176.5**	**180.4**	**193.7**	**206.1**	**240.2**	**284.7**	**323.5**	**325.2**	**311.4**	**911.7**	**1485.0**	**62.9%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	31.3	38.4	52.6	61.4	66.9	73.6	82.5	88.5	79.9	72.6	250.6	397.2	58.5%
Diversions	1.1	1.0	2.2	0.8	0.9	1.3	0.8	0.8	0.8	1.1	6.0	4.6	-23.2%
General reinforcement - P2/6	16.4	11.8	25.8	22.6	30.5	39.2	39.5	31.3	27.7	31.2	107.1	168.9	57.7%
General reinforcement - Fault Levels	0.0	0.0	0.0	1.5	3.0	0.7	0.0	0.0	0.0	0.0	4.4	0.7	-84.4%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.7	1.1	2.4	3.7	4.0	0.0	11.8	N/A
Total Load related (Gross)	**48.8**	**51.2**	**80.6**	**86.3**	**101.3**	**115.5**	**123.8**	**123.0**	**112.0**	**108.9**	**368.2**	**583.2**	**58.4%**
Customer Contributions													
Customer specific - Demand	37.5	51.7	60.4	64.4	65.0	67.2	69.6	72.6	72.2	62.4	279.0	343.9	23.3%
Total Load related (Net)	**11.3**	**-0.5**	**20.2**	**21.9**	**36.2**	**48.3**	**54.2**	**50.4**	**39.8**	**46.5**	**89.2**	**239.3**	**168.4%**
Non Load related investment													
Asset replacement	46.8	66.0	44.4	39.5	34.5	44.2	59.0	67.8	74.8	75.1	231.2	320.9	38.8%
Quality of supply (IIS)	1.1	0.6	0.7	0.6	0.8	1.4	1.4	1.4	1.4	1.4	3.8	7.0	84.2%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.0	2.5	N/A
Major system risks	0.0	0.0	0.0	0.0	0.2	1.7	10.3	27.3	27.6	6.5	0.3	73.4	27016.5%
Operational IT and telecoms	0.0	0.8	1.9	4.5	5.0	3.1	1.5	1.1	1.0	0.9	12.2	7.6	-37.7%
Environmental	1.5	0.6	0.6	1.4	1.8	6.5	15.1	24.2	23.7	18.7	5.9	88.2	1385.8%
Legal & safety	3.1	2.2	2.1	2.9	2.2	3.7	3.8	3.8	1.6	1.6	12.5	14.5	15.9%
Total Non Load related	**52.5**	**70.2**	**49.7**	**49.0**	**44.5**	**61.1**	**91.6**	**126.1**	**130.5**	**104.7**	**265.9**	**514.0**	**93.3%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.2	0.9	0.9	0.9	0.9	0.9	0.3	4.5	1545.1%
HILP	0.0	0.0	0.0	0.0	0.0	0.8	9.4	26.4	26.7	5.6	0.0	68.9	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Environmental													
Visual Amenity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A

EDFE (LPN) - August FBPQ Narrative

1.58. When submitting the draft August FBPQ submission for LPN, EDF Energy made a decision not to reflect the then recent instability of the economic climate. The underlying economic assumptions therefore remained as continued prosperity. However, LPN's network, particularly central London, is less sensitive to economic change. The proposed increase in non-load related investment during DPCR5 is a reflection of the increasing age and changing condition of the network.

1.59. As part of the August draft submission, EDF Energy has also included additional investment to increase LPN's network resilience for High Impact Low Probability (HILP) events and the deployment of future technologies (£81m in DPCR5). Although included in the tables this expenditure does not form part of EDF Energy's base case forecast. There is also an additional programme of work in DPCR5 that did not form part of the final DPCR4 settlement; the investment required to implement the recommendations of the Pitt report on flooding (£5m).

1.60. EDF Energy's August draft FBPQ submission reflects its current utilisation and mix of in-house/contracted staff. EDF Energy will be reviewing this mix to ensure it continues to provide the best value during DPCR5. EDF Energy has worked with consultants to help identify the supply-side considerations of the future utilities labour market. This initial research shows the rate of real earnings growth (i.e. the labour RPE) increases when capital investment rises in the utility sector, particularly when there is also a skills shortage. There's a strong relationship between these variables at a national level, which needs further calibration to capture the effect of the disproportionately higher infrastructure investment growth expected in London.

1.61. EDF Energy has continued to work on the quality and transparency of the regulatory cost reporting and this is reflected in the draft August FBPQ submission. In particular, the RRP rules have been rigorously applied and the same approach is carried forward within the compilation of the draft August FBPQ. In addition, due to its geographic location, LPN is subject to higher living costs than the UK average. The forecast of direct and indirect costs include the impact of these regional factors which were not fully reflected in the final DPCR4 settlement. The remaining increase in indirect costs, in the second half of DPCR4 and at the beginning of DPCR5, is primarily a function of the increasing capex programme and an ageing workforce.

1.62. To ensure LPN's customers' opinions are reflected, views received through EDF Energy's stakeholder consultation will be incorporated in the February submission. This will include concerns raised regarding available capacity headroom and network investment to improve resilience to HILP events. Other refinements to be included in the February submission for LPN include: an assessment of the special network restrictions imposed by the hosting of the 2012 Olympic games in London; an improved understanding of the opportunities around distributed generation, demand side management and energy efficiency (further informed by the Government's Renewable Energy Strategy consultation); and a more detailed assessment of any network outage constraints on engineering plans. EDF Energy will clarify the positive impact of the network investment plans in terms of asset management outcomes.

EDFE (SPN) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
EDFE SPN	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	50.0	48.3	52.2	69.6	66.0	73.3	75.5	73.1	73.2	77.1	286.1	372.1	30.1%
Customer contributions	39.0	50.4	40.0	43.0	45.2	46.8	46.4	41.2	36.3	36.7	217.5	207.3	-4.7%
Load related (net)	11.0	-2.1	12.2	26.6	20.8	26.6	29.1	31.9	36.9	40.4	68.6	164.8	140.4%
Non load related	55.6	43.2	58.7	74.4	78.9	101.4	102.8	92.5	84.8	81.6	310.8	463.2	49.0%
Total	**66.6**	**41.1**	**70.9**	**101.0**	**99.7**	**127.9**	**131.9**	**124.4**	**121.7**	**122.0**	**379.3**	**628.0**	**65.6%**
RPEs (net)				1.6	3.1	6.0	8.4	10.1	11.9	14.0	4.7	50.4	
Total (Including RPEs)	**66.6**	**41.1**	**70.9**	**102.6**	**102.8**	**133.9**	**140.3**	**134.5**	**133.6**	**136.0**	**384.0**	**678.4**	**76.7%**
Distributed Generation													
Customer specific - Generation	0.3	0.0	0.0	0.4	0.4	0.6	1.0	1.6	2.3	3.0	1.1	8.4	651.4%
Customer contributions	0.4	0.0	0.0	0.4	0.4	0.5	0.9	1.5	2.2	2.9	1.2	8.0	578.1%
Total	**-0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**-0.1**	**0.4**	**N/A**
Network Operating Costs													
Inspections and maintenance	11.1	9.2	7.6	7.8	7.7	7.7	7.7	7.7	7.7	7.7	43.4	38.5	-11.2%
Fault repairs and restoration	21.9	26.0	26.1	26.5	26.7	26.6	26.8	26.7	26.6	26.7	127.2	133.4	4.9%
Tree cutting	6.7	5.0	5.5	5.8	7.2	7.2	7.2	7.2	7.2	7.2	30.2	36.0	19.2%
Other Network costs	0.4	-2.9	-2.9	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-9.8	-11.0	N/A
Total	**40.1**	**37.3**	**36.3**	**37.9**	**39.4**	**39.3**	**39.5**	**39.4**	**39.3**	**39.4**	**191.0**	**196.9**	**3.1%**
RPEs				0.5	1.0	1.7	2.3	2.9	3.6	4.3	1.5	14.8	
Total (Including RPEs)	**40.1**	**37.3**	**36.3**	**38.4**	**40.4**	**41.0**	**41.8**	**42.3**	**42.9**	**43.7**	**192.5**	**211.7**	**10.0%**
Indirect Costs													
Engineering Indirects	16.0	15.5	20.1	26.1	25.2	26.6	26.8	26.2	25.9	25.7	102.9	131.2	27.5%
Network/Investment Support	16.5	16.7	16.3	18.8	20.6	21.3	21.3	21.4	21.0	20.8	88.9	105.8	19.0%
Business Support	27.3	25.0	28.8	30.2	30.0	29.2	29.7	29.5	29.1	28.5	141.3	146.0	3.3%
Non-operational capex	5.2	10.3	7.4	11.0	12.2	11.7	11.7	11.7	9.2	9.6	46.1	53.9	17.0%
Total	**65.0**	**67.5**	**72.6**	**86.1**	**88.0**	**88.8**	**89.5**	**88.8**	**85.2**	**84.6**	**379.2**	**436.9**	**15.2%**
RPEs				1.2	2.4	3.7	4.9	6.0	7.1	8.3	3.6	30.0	
Total (Including RPEs)	**65.0**	**67.5**	**72.6**	**87.3**	**90.4**	**92.5**	**94.4**	**94.8**	**92.3**	**92.9**	**382.8**	**466.9**	**22.0%**
Total	**171.6**	**145.9**	**179.8**	**225.0**	**227.1**	**256.1**	**261.0**	**252.7**	**246.3**	**246.1**	**949.4**	**1262.2**	**32.9%**
Total RPEs				3.3	6.5	11.4	15.6	19.0	22.6	26.6	9.8	95.2	
Total (Including RPEs)	**171.6**	**145.9**	**179.8**	**228.3**	**233.6**	**267.5**	**276.6**	**271.7**	**268.9**	**272.7**	**959.2**	**1357.4**	**41.5%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	36.8	38.8	36.6	48.9	43.0	47.0	46.4	42.6	37.1	37.9	204.1	211.0	3.4%
Diversions	2.8	2.5	3.9	6.0	4.6	4.8	3.9	3.9	4.9	6.9	19.8	24.3	22.9%
General reinforcement - P2/6	10.4	7.0	11.1	14.3	16.2	16.7	16.2	19.1	24.5	26.0	59.1	102.5	73.5%
General reinforcement - Fault Levels	0.0	0.0	0.6	0.5	2.1	4.1	7.6	4.5	2.2	1.2	3.2	19.6	522.3%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.7	1.4	3.0	4.5	5.1	0.0	14.6	N/A
Total Load related (Gross)	**50.0**	**48.3**	**52.2**	**69.6**	**66.0**	**73.3**	**75.5**	**73.1**	**73.2**	**77.1**	**286.1**	**372.1**	**30.1%**
Customer Contributions													
Customer specific - Demand	39.0	50.4	40.0	43.0	45.2	46.8	46.4	41.2	36.3	36.7	217.5	207.3	-4.7%
Total Load related (Net)	**11.0**	**-2.1**	**12.2**	**26.6**	**20.8**	**26.6**	**29.1**	**31.9**	**36.9**	**40.4**	**68.6**	**164.8**	**140.4%**
Non Load related investment													
Asset replacement	43.1	30.1	44.7	53.7	55.4	66.0	69.4	59.2	55.4	58.0	227.0	308.1	35.7%
Quality of supply (IIS)	3.8	5.4	4.4	3.2	2.8	4.2	4.2	4.2	4.2	4.2	19.6	21.0	7.1%
Quality of supply (non IIS)	2.2	2.1	5.5	0.0	0.0	1.5	1.5	1.5	1.5	1.5	9.8	7.5	-23.5%
Major system risks	0.0	0.0	0.0	0.2	0.3	1.3	1.3	1.3	1.3	1.3	0.5	6.5	1200.0%
Operational IT and telecoms	3.1	3.1	0.8	1.3	2.7	7.8	7.9	7.6	6.0	1.3	11.0	30.6	178.2%
Environmental	1.2	0.6	0.9	8.3	7.9	7.4	2.6	2.8	3.5	3.4	18.9	19.7	4.2%
Legal & safety	2.2	1.9	2.4	7.7	9.8	13.2	15.9	15.9	12.9	11.9	24.0	69.8	190.8%
Total Non Load related	**55.6**	**43.2**	**58.7**	**74.4**	**78.9**	**101.4**	**102.8**	**92.5**	**84.8**	**81.6**	**310.8**	**463.2**	**49.0%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.2	0.3	1.3	1.3	1.3	1.3	1.3	0.5	6.5	1200.0%
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	1.7	6.6	6.6	6.6	5.1	0.5	1.7	25.4	1394.1%
Legal & safety													
ESQCR	0.0	0.0	0.0	5.5	8.1	8.0	10.9	10.9	10.9	9.9	13.6	50.6	272.1%
Environmental													
Visual Amenity	0.0	0.0	0.1	3.3	1.8	1.1	1.1	1.1	1.1	1.1	5.2	5.5	5.8%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A

EDFE (SPN) - August FBPQ Narrative

1.63. When submitting the draft August FBPQ submission for SPN, EDF Energy made a decision not to reflect the then recent instability of the economic climate. The underlying economic assumptions therefore remained as continued prosperity. EDF Energy is working with to reflect a more informed view of the short-to-medium term economic trends in the February FBPQ submission. This revised view will also include a further assessment of the future impact of Distributed Generation and Energy efficiency. The proposed increase in non-load related investment during DPCR5 is a reflection of the increasing age and changing condition of the network.

1.64. As part of the August draft submission EDF Energy also included additional investment for the deployment of future technologies (£15m in SPN for DPCR5). Although included in the tables this expenditure does not form part of EDF Energy's base case forecast. There are also a number of additional required programmes of work in DPCR5 that did not form part of the final DPCR4 settlement. For example BT launched a project to improve their telephone network provision. This requires significant investment within SPN’s network (£25m) to ensure continuation of power supply. Additional expenditure has also been included for the increased investment requirements arising from the changes to the electricity safety, quality and continuity regulations (ESQCR) and the recommendations from the Pitt report into the flooding risk in the UK (£57m).

1.65. EDF Energy has continued to work on the quality and transparency of the regulatory cost reporting and this is reflected in the draft August FBPQ submission. In particular, the RRP rules have been rigorously applied and the same approach is carried forward within the compilation of the draft August FBPQ. The increase in indirect costs, in the second half of DPCR4 and at the beginning of DPCR5, is primarily a function of the increasing capex programme and an ageing workforce. In addition, due to its geographic location, a significant part of the EPN region is subject to higher living costs than the UK average. The forecast of direct and indirect costs include the impact of these regional factors which were not fully reflected in the final DPCR4 settlement.

1.66. To ensure SPN’s customers’ opinions are reflected, views received through EDF Energy’s stakeholder consultation will be incorporated in the February submission. This will include concerns raised regarding available capacity headroom to accommodate new development, a potential extension to the Areas of Outstanding Natural Beauty undergrounding programme in the South East of England and the deployment of new technologies into the SPN network.

1.67. Other refinements to be included in the February submission for the SPN network include: an improved understanding of the opportunities around distributed generation, demand side management and energy efficiency (further informed by the Government’s Renewable Energy Strategy consultation); a fuller assessment of the impact of the required nuclear power station enabling works for Dungeness and a more detailed assessment of any network outage constraints on engineering plans. EDF Energy will clarify the positive impact of the network investment plans in terms of both asset management outcomes and transparent customer benefits.

EDFE (EPN) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
EDFE EPN	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	94.1	99.8	114.2	124.3	134.3	147.3	145.0	144.7	155.2	163.5	566.7	755.8	33.4%
Customer contributions	76.5	73.5	72.1	79.4	84.0	85.7	83.2	80.8	81.9	88.0	385.5	419.5	8.8%
Load related (net)	17.6	26.3	42.1	44.9	50.3	61.6	61.8	63.9	73.3	75.5	181.2	336.2	85.6%
Non load related	55.3	59.5	73.9	90.8	97.1	122.3	128.8	126.5	110.4	99.5	376.6	587.5	56.0%
Total	**72.9**	**85.8**	**116.0**	**135.7**	**147.4**	**183.9**	**190.6**	**190.4**	**183.7**	**175.0**	**557.8**	**923.7**	**65.6%**
RPEs (net)				2.5	4.9	8.5	11.7	14.7	17.2	19.4	7.4	71.5	
Total (Including RPEs)	**72.9**	**85.8**	**116.0**	**138.2**	**152.3**	**192.4**	**202.3**	**205.1**	**200.9**	**194.4**	**565.2**	**995.2**	**76.1%**
Distributed Generation													
Customer specific - Generation	2.9	1.8	0.7	0.7	0.7	1.2	1.5	3.1	4.0	4.9	6.8	14.6	114.1%
Customer contributions	4.0	2.6	1.0	0.7	0.7	1.1	1.4	3.0	3.9	4.8	8.9	14.0	56.0%
Total	**-1.1**	**-0.8**	**-0.3**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**-2.1**	**0.7**	**N/A**
Network Operating Costs													
Inspections and maintenance	12.2	13.0	10.8	10.9	11.0	11.0	11.0	11.0	11.0	11.0	57.9	55.0	-5.0%
Fault repairs and restoration	28.5	38.7	45.0	40.1	40.4	40.4	40.4	40.5	40.6	40.6	192.7	202.5	5.1%
Tree cutting	10.9	9.4	8.4	10.9	17.4	17.4	17.4	17.4	17.4	17.4	57.0	87.0	52.6%
Other Network costs	0.8	-2.0	-2.9	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-11.3	-18.0	N/A
Total	**52.4**	**59.1**	**61.3**	**58.3**	**65.2**	**65.2**	**65.2**	**65.3**	**65.4**	**65.4**	**296.3**	**326.5**	**10.2%**
RPEs				0.7	1.6	2.5	3.5	4.5	5.5	6.5	2.3	22.5	
Total (Including RPEs)	**52.4**	**59.1**	**61.3**	**59.0**	**66.8**	**67.7**	**68.7**	**69.8**	**70.9**	**71.9**	**298.6**	**349.0**	**16.9%**
Indirect Costs													
Engineering Indirects	25.8	29.7	38.7	44.9	45.5	47.3	47.4	47.1	46.7	46.5	184.6	235.0	27.3%
Network/Investment Support	22.6	26.4	26.0	30.0	32.7	33.8	34.2	34.4	34.0	33.5	137.7	169.9	23.4%
Business Support	39.7	37.5	43.2	45.5	45.4	45.8	47.1	46.9	46.1	45.3	211.3	231.2	9.4%
Non-operational capex	9.4	11.9	18.6	20.1	20.6	18.0	15.7	13.8	15.5	17.5	80.6	80.5	-0.1%
Total	**97.5**	**105.5**	**126.5**	**140.5**	**144.2**	**144.9**	**144.4**	**142.2**	**142.3**	**142.8**	**614.2**	**716.6**	**16.7%**
RPEs				2.2	4.1	6.2	8.2	10.3	12.3	14.6	6.3	51.6	
Total (Including RPEs)	**97.5**	**105.5**	**126.5**	**142.7**	**148.3**	**151.1**	**152.6**	**152.5**	**154.6**	**157.4**	**620.5**	**768.2**	**23.8%**
Total	**221.7**	**249.6**	**303.5**	**334.5**	**356.8**	**394.1**	**400.4**	**398.1**	**391.6**	**383.4**	**1466.2**	**1967.4**	**34.2%**
Total RPEs				5.4	10.6	17.2	23.4	29.5	35.0	40.5	16.0	145.6	
Total (Including RPEs)	**221.7**	**249.6**	**303.5**	**339.9**	**367.4**	**411.3**	**423.8**	**427.6**	**426.6**	**423.9**	**1482.2**	**2113.0**	**42.6%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	59.6	60.6	63.0	83.6	82.0	88.8	86.3	79.6	79.1	81.7	348.9	415.6	19.1%
Diversions	4.2	7.9	6.2	5.6	5.8	6.8	7.5	7.5	7.5	7.5	29.6	36.7	23.8%
General reinforcement - P2/6	30.3	31.3	32.4	33.4	42.7	45.2	46.1	51.0	60.6	67.5	170.2	270.5	59.0%
General reinforcement - Fault Levels	0.0	0.0	12.6	1.7	3.7	5.2	3.1	2.6	2.2	0.0	18.0	13.2	-26.8%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	1.3	2.0	4.0	5.8	6.8	0.0	19.8	N/A
Total Load related (Gross)	**94.1**	**99.8**	**114.2**	**124.3**	**134.3**	**147.3**	**145.0**	**144.7**	**155.2**	**163.5**	**566.7**	**755.8**	**33.4%**
Customer Contributions													
Customer specific - Demand	76.5	73.5	72.1	79.4	84.0	85.7	83.2	80.8	81.9	88.0	385.5	419.5	8.8%
Total Load related (Net)	**17.6**	**26.3**	**42.1**	**44.9**	**50.3**	**61.6**	**61.8**	**63.9**	**73.3**	**75.5**	**181.2**	**336.2**	**85.6%**
Non Load related investment													
Asset replacement	38.7	41.6	51.9	57.2	63.2	76.5	80.4	78.7	73.8	72.6	252.7	382.0	51.2%
Quality of supply (IIS)	3.0	3.5	3.2	4.4	5.0	4.6	4.6	4.6	4.6	4.6	19.1	23.0	20.4%
Quality of supply (non IIS)	6.9	6.9	8.5	0.0	0.0	1.5	1.5	1.5	1.5	1.5	22.3	7.5	-66.4%
Major system risks	0.0	0.0	0.0	0.2	0.4	1.5	1.5	1.5	1.5	1.5	0.6	7.5	1150.0%
Operational IT and telecoms	0.0	0.2	0.3	2.2	4.4	12.0	11.9	10.5	8.0	1.4	7.1	43.8	516.0%
Environmental	1.0	2.2	1.8	7.9	6.5	3.2	6.0	7.2	6.3	5.9	19.4	28.6	47.4%
Legal & safety	5.7	5.1	8.2	18.9	17.5	23.0	22.9	22.5	14.7	12.0	55.4	95.1	71.7%
Total Non Load related	**55.3**	**59.5**	**73.9**	**90.8**	**97.1**	**122.3**	**128.8**	**126.5**	**110.4**	**99.5**	**376.6**	**587.5**	**56.0%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.2	0.4	1.5	1.5	1.5	1.5	1.5	0.6	7.5	1150.0%
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	2.3	9.3	9.3	9.3	7.2	0.7	2.3	35.8	1456.5%
Legal & safety													
ESQCR	0.0	0.0	0.0	13.6	12.4	10.9	10.8	10.4	9.9	8.2	26.0	50.2	93.1%
Environmental													
Visual Amenity	0.0	0.3	0.1	0.5	0.4	0.4	0.4	0.4	0.4	0.4	1.3	2.0	53.8%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A

EDFE (EPN) - August Draft FBPQ Narrative

1.68. When submitting the draft August FBPQ submission for EPN, EDF Energy made a decision not to reflect the then recent instability of the economic climate. The underlying economic assumptions therefore remained as continued prosperity. EDF Energy is working to reflect a more informed view of the short-to-medium term economic trends in their February FBPQ submission. The proposed increase in non-load related investment during DPCR5 is a reflection of the increasing age and changing condition of the network.

1.69. As part of the August draft submission EDF Energy also included additional investment for the deployment of future technologies (£20m in EPN for DPCR5). Although included in the tables this expenditure does not form part of EDF Energy's base case forecast. There are also a number of additional required programmes of work in DPCR5 that did not form part of the final DPCR4 settlement. For example BT launched a project to improve their telephone network provision. This requires significant investment within EPN’s network (£36m) to ensure continuation of power supply. Additional expenditure has also been included for the increased investment requirements arising from the changes to the electricity safety, quality and continuity regulations (ESQCR) and the recommendations of the Pitt report into the flooding risk in the UK (£58m).

1.70. EDF Energy has continued to work on the quality and transparency of the regulatory cost reporting and this is reflected in the draft August FBPQ submission. In particular, the RRP rules have been rigorously applied and the same approach is carried forward within the compilation of the draft August FBPQ. The increase in indirect costs, in the second half of DPCR4 and at the beginning of DPCR5, is primarily a function of the increasing capex programme and an ageing workforce. In addition, due to its geographic location, EPN is subject to higher living costs than the UK average. The forecast of direct and indirect costs include the impact of these regional factors which were not fully reflected in the final DPCR4 settlement.

1.71. To ensure EPN’s customers’ opinions are reflected, views received through EDF Energy’s stakeholder consultation will be incorporated in the February submission. This will include concerns raised regarding available capacity headroom to accommodate new development, a potential extension to the Areas of Outstanding Natural Beauty undergrounding programme in the East of England and the deployment of new technologies into the EPN network.

1.72. Other refinements to be included in EDF Energy’s February submission for the EPN network include: a fuller assessment of the impact of NGET’s proposed injection of substantial offshore wind generation into East Anglia and the required nuclear power station enabling works for Sizewell and Bradwell; an improved understanding of the opportunities around distributed generation, demand side management and energy efficiency (further informed by the Government’s Renewable Energy Strategy consultation); and a more detailed assessment of any network outage constraints on engineering plans. EDF Energy will clarify the positive impact of EDF Energy’s network investment plans in terms of both asset management outcomes and transparent customer benefits.

SP (Distribution) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
SP Dist	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	47.1	51.3	49.3	51.6	58.2	62.2	67.8	63.8	64.8	60.8	257.5	319.5	24.0%
Customer contributions	44.2	40.7	40.1	41.2	41.2	42.2	42.3	41.3	41.2	41.2	207.4	208.2	0.4%
Load related (net)	2.9	10.6	9.2	10.5	17.0	20.0	25.5	22.5	23.6	19.6	50.2	111.2	121.6%
Non load related	33.7	50.1	62.4	63.1	60.9	72.2	74.4	79.2	85.4	83.4	270.1	394.6	46.1%
Total	**36.5**	**60.7**	**71.5**	**73.5**	**78.0**	**92.2**	**99.9**	**101.7**	**109.0**	**103.0**	**320.2**	**505.8**	**58.0%**
RPEs (net)				4.6	8.1	16.7	23.1	29.2	36.9	41.6	12.7	147.5	
Total (Including RPEs)	**36.5**	**60.7**	**71.5**	**78.1**	**86.1**	**108.9**	**123.0**	**130.9**	**145.9**	**144.6**	**332.9**	**653.4**	**96.2%**
Distributed Generation													
Customer specific - Generation	3.1	16.8	9.6	20.3	22.0	22.6	26.8	25.1	30.0	32.0	71.9	136.6	89.8%
Customer contributions	3.0	22.4	10.5	19.5	21.2	18.0	21.9	22.5	24.7	26.6	76.6	113.7	48.4%
Total	**0.1**	**-5.6**	**-0.9**	**0.8**	**0.9**	**4.6**	**5.0**	**2.6**	**5.3**	**5.4**	**-4.6**	**22.9**	**N/A**
Network Operating Costs													
Inspections and maintenance	7.9	5.1	5.0	4.7	4.9	5.8	5.7	5.7	5.7	5.7	27.6	28.7	3.9%
Fault repairs and restoration	16.1	16.2	15.5	15.7	15.7	15.8	15.8	15.9	16.1	16.1	79.2	79.7	0.6%
Tree cutting	3.7	3.0	4.8	5.5	6.5	5.8	6.4	6.9	6.9	7.1	23.6	33.1	40.4%
Other Network costs	-1.1	0.3	-0.4	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-1.4	-0.5	N/A
Total	**26.6**	**24.7**	**24.9**	**25.8**	**27.0**	**27.3**	**27.8**	**28.4**	**28.6**	**28.8**	**129.0**	**141.0**	**9.3%**
RPEs				1.2	2.1	3.1	3.9	5.0	6.0	7.0	3.4	25.0	
Total (Including RPEs)	**26.6**	**24.7**	**24.9**	**27.0**	**29.2**	**30.4**	**31.8**	**33.4**	**34.6**	**35.9**	**132.4**	**166.1**	**25.4%**
Indirect Costs													
Engineering Indirects	24.6	20.4	22.6	22.2	22.5	23.0	23.5	23.7	23.7	23.7	112.4	117.7	4.7%
Network/Investment Support	47.3	42.6	37.3	36.7	37.2	37.3	37.4	37.5	37.5	37.5	201.1	187.0	-7.0%
Business Support	1.7	1.8	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	8.1	7.6	-5.9%
Non-operational capex	7.5	6.7	2.5	2.0	2.0	3.6	2.6	2.5	2.7	2.9	20.7	14.2	-31.3%
Total	**81.1**	**71.5**	**63.9**	**62.4**	**63.2**	**65.3**	**65.0**	**65.1**	**65.4**	**65.6**	**342.2**	**326.5**	**-4.6%**
RPEs				1.6	3.2	5.8	8.0	10.7	12.7	14.8	4.8	52.1	
Total (Including RPEs)	**81.1**	**71.5**	**63.9**	**64.0**	**66.5**	**71.1**	**73.0**	**75.9**	**78.1**	**80.4**	**347.0**	**378.6**	**9.1%**
Total	**144.4**	**151.3**	**159.5**	**162.6**	**169.1**	**189.5**	**197.7**	**197.9**	**208.3**	**202.8**	**786.8**	**996.2**	**26.6%**
Total RPEs				7.4	13.5	25.6	35.1	44.9	55.6	63.5	20.9	224.6	
Total (Including RPEs)	**144.4**	**151.3**	**159.5**	**170.0**	**182.5**	**215.0**	**232.8**	**242.8**	**263.9**	**266.3**	**807.7**	**1220.8**	**51.2%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	40.5	38.5	36.1	37.6	37.6	39.0	40.7	38.1	37.6	37.6	190.3	193.0	1.4%
Diversions	2.1	3.0	2.7	2.3	2.3	2.3	2.3	2.3	2.3	2.3	12.4	11.5	-7.5%
General reinforcement - P2/6	4.5	9.8	9.6	11.8	17.6	16.2	15.6	14.9	16.5	18.5	53.3	81.7	53.4%
General reinforcement - Fault Levels	0.0	0.0	0.8	0.0	0.7	4.7	9.2	8.3	6.3	1.2	1.5	29.7	1871.7%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.1	1.2	0.0	3.6	N/A
Total Load related (Gross)	**47.1**	**51.3**	**49.3**	**51.6**	**58.2**	**62.2**	**67.8**	**63.8**	**64.8**	**60.8**	**257.5**	**319.5**	**24.0%**
Customer Contributions													
Customer specific - Demand	44.2	40.7	40.1	41.2	41.2	42.2	42.3	41.3	41.2	41.2	207.4	208.2	0.4%
Total Load related (Net)	**2.9**	**10.6**	**9.2**	**10.5**	**17.0**	**20.0**	**25.5**	**22.5**	**23.6**	**19.6**	**50.2**	**111.2**	**121.6%**
Non Load related investment													
Asset replacement	30.2	40.2	49.1	51.7	53.6	45.2	49.2	53.5	57.6	59.2	224.8	264.7	17.7%
Quality of supply (IIS)	2.1	8.0	7.7	3.7	0.2	3.9	3.8	3.7	3.8	0.0	21.6	15.2	-29.6%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	0.0	10.0	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	2.0	1.4	1.4	1.4	1.4	0.0	7.6	N/A
Operational IT and telecoms	1.2	0.9	2.7	1.7	0.5	2.6	2.0	1.5	1.0	0.8	7.0	7.8	11.0%
Environmental	0.1	0.2	0.0	0.9	0.4	5.0	5.6	6.0	6.5	6.7	1.6	29.8	1752.8%
Legal & safety	0.0	0.8	2.9	5.1	6.2	11.5	10.4	11.1	13.1	13.3	15.0	59.5	297.1%
Total Non Load related	**33.7**	**50.1**	**62.4**	**63.1**	**60.9**	**72.2**	**74.4**	**79.2**	**85.4**	**83.4**	**270.1**	**394.6**	**46.1%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	1.0	1.4	1.4	1.4	1.4	0.0	6.6	N/A
HILP	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	1.0	N/A
Operational IT and telecoms													
BT21C			2.5	0.0	0.0	1.2	0.9	0.9	0.0	0.0	2.5	2.9	17.7%
Legal & safety													
ESQCR	0.0	0.0	0.0	4.9	5.1	3.5	2.0	2.0	1.4	0.0	10.0	9.0	-10.0%
Environmental													
Visual Amenity	0.0	0.0	0.0	0.5	0.0	2.3	2.8	3.1	3.6	3.8	0.5	15.6	3022.0%
Technical Losses				0.0	0.0	1.6	1.7	1.8	1.8	1.8	0.0	8.7	N/A
Tree cutting													
ETR-132			1.5	1.9	2.9	2.2	2.8	3.3	3.3	3.5	6.3	15.1	139.7%

SP (Distribution) - August FBPQ Narrative

1.73. Our investment plans have been developed through rigorous consideration of network requirements and consultation with a wide range of stakeholders. Our underlying 'Base Case' capital investment plan, (i.e. excluding new and emerging issues, distributed generation and RPEs), amounts to c. £398m (£80m per annum) at 07-08 prices, an increase of c. £20m p.a (35%) period on period. The plans include a significant number of schemes which we have had to defer from DPCR4 as a consequence of unavoidable above RPI rises in input prices and to manage expenditure within Ofgem’s allowance.

1.74. Load-related investment of c. £22m p.a (net) is necessary to accommodate growth, changes to the capacity of existing connections and demand movement.

1.75. The majority of non-load related investment is asset replacement of c £53m p.a, necessary to ensure the safety and integrity of our network over the short and longer term. We intend to invest c. £20m p.a to improve service for our rural customers by upgrading Overhead Lines, improving storm resilience and reducing supply interruptions. In our urban areas we will invest c. £10m p.a in improvements to our underground cable network, targeted at removing the poorest performing 33kV and 11kV circuits. c. £23m p.a will be invested in substations to address the deteriorating failure rate of 33kV transformers and 11kV switchgear and to improve the condition of civil structures.

1.76. In addition to the Base Case, our plans also include investments necessary to manage new and emerging issues; For example, c. £8m p.a of new expenditure will be directed toward managing public safety risks arising from the deterioration in condition of LV internal mains. A further £2m p.a will be invested to ensure compliance with new legal obligations (ESQCR) associated with overhead line clearances. New expenditure of c. £1.5m p.a is included to address flood risks and to meet BERR requirements for providing security of supply to Central Business Districts in Cities (HILP). Around £5m p.a to reduce the level of technical losses of distribution equipment and minimise the impact of our lines in areas of high visual amenity is also included in our plans.

1.77. In common with ten other DNO’s operating costs are now above the DPCR4 allowance. In our opinion upper quartile regression and efficiency stretches are no longer sustainable and the building block approach adopted by OFGEM for DPCR5 will only be successful if specific cost drivers are identified that lead to a more equitable settlement. Tree management costs are a good example, where the density of trees and number of spans affected are relevant and key cost drivers.

1.78. Based on currently available information, RPEs could amount to some £225m over DPCR5. Whilst we do not regard RPEs as part of our core submission, it will be necessary for Ofgem to establish a mechanism to deal with this issue, in the form for example, of balanced indexation.

SP (Manweb) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
SP Manweb	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	45.4	41.2	46.6	49.3	53.7	60.1	66.6	67.1	74.7	65.1	236.2	333.7	41.3%
Customer contributions	30.9	25.6	40.1	35.0	34.6	36.1	33.5	33.5	37.4	33.5	166.2	174.0	4.7%
Load related (net)	14.5	15.6	6.5	14.3	19.1	24.0	33.1	33.6	37.4	31.6	70.0	159.7	128.2%
Non load related	39.5	55.5	70.0	77.2	74.2	109.4	101.8	105.7	105.3	99.0	316.3	521.2	64.8%
Total	**54.0**	**71.1**	**76.4**	**91.5**	**93.3**	**133.4**	**135.0**	**139.3**	**142.6**	**130.6**	**386.3**	**681.0**	**76.3%**
RPEs (net)				5.3	10.4	22.0	28.5	35.8	47.3	62.7	15.7	196.2	
Total (Including RPEs)	**54.0**	**71.1**	**76.4**	**96.8**	**103.7**	**155.4**	**163.4**	**175.1**	**189.9**	**193.3**	**402.1**	**877.2**	**118.2%**
Distributed Generation													
Customer specific - Generation	1.4	0.9	4.1	8.1	93.1	1.8	11.6	6.3	19.9	17.4	107.5	57.0	-47.0%
Customer contributions	1.2	0.6	3.2	6.5	79.2	1.1	8.3	5.1	15.6	13.6	90.6	43.7	-51.7%
Total	**0.2**	**0.3**	**0.9**	**1.6**	**13.9**	**0.8**	**3.2**	**1.2**	**4.3**	**3.8**	**16.9**	**13.3**	**-21.4%**
Network Operating Costs													
Inspections and maintenance	8.2	7.7	5.9	6.1	6.3	8.0	8.6	9.3	9.3	9.3	34.2	44.6	30.4%
Fault repairs and restoration	17.0	15.4	13.9	13.4	13.4	13.4	13.6	13.8	13.8	13.8	73.1	68.4	-6.5%
Tree cutting	6.2	5.4	8.8	8.0	9.8	10.6	11.1	11.4	11.5	11.8	38.2	56.6	48.2%
Other Network costs	-1.0	-1.6	-0.9	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-6.1	-6.5	N/A
Total	**30.4**	**27.0**	**27.7**	**26.2**	**28.2**	**30.8**	**32.1**	**33.3**	**33.4**	**33.7**	**139.5**	**163.1**	**17.0%**
RPEs				1.3	2.4	3.8	5.0	6.5	7.7	9.0	3.7	32.0	
Total (Including RPEs)	**30.4**	**27.0**	**27.7**	**27.5**	**30.6**	**34.5**	**37.0**	**39.7**	**41.1**	**42.7**	**143.2**	**195.1**	**36.2%**
Indirect Costs													
Engineering Indirects	24.3	17.7	20.5	20.8	21.8	22.6	23.4	23.8	23.8	23.8	105.1	117.5	11.8%
Network/Investment Support	48.6	38.9	36.1	36.5	38.3	38.5	38.8	38.9	38.9	38.9	198.4	193.9	-2.3%
Business Support	1.8	1.7	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	8.0	7.8	-2.0%
Non-operational capex	5.5	4.6	2.9	2.0	2.0	3.6	2.6	2.5	2.7	2.9	17.1	14.2	-16.7%
Total	**80.2**	**62.9**	**60.9**	**60.8**	**63.8**	**66.3**	**66.4**	**66.7**	**67.0**	**67.2**	**328.7**	**333.5**	**1.5%**
RPEs				1.5	3.3	5.8	7.8	10.3	12.2	14.3	4.8	50.3	
Total (Including RPEs)	**80.2**	**62.9**	**60.9**	**62.4**	**67.0**	**72.0**	**74.1**	**77.0**	**79.2**	**81.5**	**333.4**	**383.8**	**15.1%**
Total	**164.9**	**161.3**	**166.0**	**180.1**	**199.1**	**231.2**	**236.6**	**240.5**	**247.2**	**235.3**	**871.3**	**1190.9**	**36.7%**
Total RPEs				8.2	16.1	31.5	41.2	52.5	67.2	86.1	24.3	278.5	
Total (Including RPEs)	**164.9**	**161.3**	**166.0**	**188.3**	**215.2**	**262.7**	**277.9**	**293.0**	**314.4**	**321.4**	**895.6**	**1469.3**	**64.1%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	30.3	35.2	37.6	34.1	32.1	34.9	32.9	32.9	38.9	32.9	169.3	172.5	1.9%
Diversions	2.6	2.4	1.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4	11.5	12.0	4.6%
General reinforcement - P2/6	12.5	3.6	2.9	9.0	15.6	19.5	22.8	25.0	26.6	23.3	43.6	117.3	169.1%
General reinforcement - Fault Levels	0.0	0.0	4.3	3.9	3.6	3.3	8.5	4.8	4.6	5.4	11.8	26.6	124.7%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.2	1.1	0.0	5.3	N/A
Total Load related (Gross)	**45.4**	**41.2**	**46.6**	**49.3**	**53.7**	**60.1**	**66.6**	**67.1**	**74.7**	**65.1**	**236.2**	**333.7**	**41.3%**
Customer Contributions													
Customer specific - Demand	30.9	25.6	40.1	35.0	34.6	36.1	33.5	33.5	37.4	33.5	166.2	174.0	4.7%
Total Load related (Net)	**14.5**	**15.6**	**6.5**	**14.3**	**19.1**	**24.0**	**33.1**	**33.6**	**37.4**	**31.6**	**70.0**	**159.7**	**128.2%**
Non Load related investment													
Asset replacement	37.3	46.8	54.3	57.2	52.3	57.5	61.4	66.3	72.9	75.3	247.9	333.4	34.5%
Quality of supply (IIS)	1.5	6.1	8.6	1.2	0.8	7.4	7.1	7.2	6.9	0.0	18.2	28.5	56.0%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	0.0	10.0	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	4.3	4.5	3.7	3.7	3.7	0.0	19.9	N/A
Operational IT and telecoms	0.5	1.0	1.3	3.6	4.1	9.8	10.9	12.5	4.4	2.0	10.6	39.6	274.2%
Environmental	0.2	0.6	1.4	1.4	1.8	6.8	7.6	5.5	5.5	5.5	5.4	30.8	469.4%
Legal & safety	0.0	0.9	4.4	13.8	15.1	21.6	8.4	8.6	10.0	10.6	34.2	59.1	72.7%
Total Non Load related	**39.5**	**55.5**	**70.0**	**77.2**	**74.2**	**109.4**	**101.8**	**105.7**	**105.3**	**99.0**	**316.3**	**521.2**	**64.8%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	3.5	3.7	3.7	3.7	3.7	0.0	18.3	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.0	0.0	0.0	0.0	1.6	N/A
Operational IT and telecoms													
BT21C			0.4	1.2	2.0	8.0	9.6	9.5	1.5	0.0	3.6	28.6	685.7%
Legal & safety													
ESQCR	0.0	0.0	0.0	13.7	15.0	17.8	4.3	4.3	4.3	4.3	28.7	34.9	21.6%
Environmental													
Visual Amenity	0.0	0.0	0.8	1.0	1.4	2.6	2.6	2.6	2.6	2.6	3.2	12.9	304.1%
Technical Losses				0.0	0.0	1.9	1.9	2.0	2.0	2.0	0.0	9.8	N/A
Tree cutting													
ETR-132			0.9	1.4	1.8	1.9	2.4	2.7	2.8	3.1	4.1	12.9	213.3%

SP (Manweb) - August FBPQ Narrative

1.79. Our investment plans have been developed through rigorous consideration of network requirements and consultation with a wide range of stakeholders. Our underlying 'Base Case' capital investment plan, (i.e. excluding new and emerging issues, distributed generation and RPEs), amounts to c. £526m (£105m p.a) at 07-08 prices, an increase of c. £38m p.a (56%) period on period. The plans include a significant number of schemes which we have had to defer from DPCR4 as a consequence of unavoidable above RPI rises in input prices and to manage expenditure within Ofgem's allowance.

1.80. Load-related investment of c. £31m p.a (net) is necessary to accommodate growth, changes to the capacity of existing connections and demand movement. The majority of non-load related investment is asset replacement of c £67m p.a, necessary to ensure the safety and integrity of our network over the short and longer term. We intend to invest c. £22m p.a to improve service for our rural customers by upgrading Overhead Lines, improving storm resilience and reducing supply interruptions. In our urban areas we will invest c. £13m p.a in improvements to our underground cable network, targeted at removing the poorest performing 33kV and 11kV circuits. c. £32m p.a will be invested in substations to address the deteriorating failure rate of 33kV transformers and 11kV switchgear and to improve the condition of civil structures.

1.81. In addition to the Base Case, our plans also include investments necessary to manage new and emerging issues; For example, c. £2m p.a of new expenditure will be directed toward managing public safety risks arising from the deterioration in condition of LV internal mains. A further £7m p.a will be invested to ensure compliance with new legal obligations (ESQCR) associated with overhead line clearances. New expenditure of c. £4m p.a is included to address flood risks and to meet BERR requirements for providing security of supply to Central Business Districts in Cities (HILP). Approx £6m p.a is necessary to address security of supply risks arising from BT's decision to upgrade its telecommunications network and withdraw services which we currently use for network protection and control purposes. Around £5m p.a to reduce the level of technical losses of distribution equipment and improve visual amenity in AONB is also included in our plans.

1.82. Although SPM's interconnected network delivers industry leading customer service (CI), the costs of operating and maintaining this unique network design are high in comparison to other DNOs. This was not recognised by Ofgem in DPCR4 and consequently, SPM's operating costs are well above the DPCR4 allowance. In order to continue to maintain current levels of service for our customers it will be necessary for Ofgem to provide an additional allowance in DPCR5.

1.83. Based on currently available information, RPEs could amount to some £278m over DPCR5. Whilst we do not regard RPEs as part of our core submission, it will be necessary for Ofgem to establish a mechanism to deal with this issue, in the form for example, of balanced indexation.

SSE (Hydro) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
SSE Hydro	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Network Investment													
Load related (gross)	11.0	14.6	14.9	22.3	17.5	13.8	13.7	13.9	13.7	14.1	80.3	69.2	-13.8%
Customer contributions	24.6	16.0	12.1	10.1	5.6	5.8	6.1	6.4	6.8	7.0	68.5	32.1	-53.1%
Load related (net)	-13.6	-1.5	2.8	12.2	11.9	8.0	7.6	7.5	6.9	7.1	11.8	37.1	214.4%
Non load related	19.7	24.6	28.3	30.1	29.5	35.9	36.0	36.0	35.5	35.4	132.1	179.0	35.5%
Total	**6.0**	**23.1**	**31.1**	**42.3**	**41.3**	**43.9**	**43.6**	**43.5**	**42.4**	**42.5**	**143.9**	**216.0**	**50.2%**
RPEs (net)				0.8	1.9	2.8	3.8	5.1	5.0	5.2	2.7	21.9	
Total (Including RPEs)	**6.0**	**23.1**	**31.1**	**43.1**	**43.2**	**46.7**	**47.4**	**48.6**	**47.4**	**47.7**	**146.6**	**237.9**	**62.3%**
Distributed Generation													
Customer specific - Generation	8.9	3.8	2.3	9.4	9.3	11.4	11.4	11.4	11.4	11.4	33.7	57.0	69.1%
Customer contributions	0.0	4.9	2.6	8.7	8.3	9.0	9.0	9.0	9.0	9.0	24.5	45.0	83.8%
Total	**8.9**	**-1.0**	**-0.3**	**0.7**	**1.0**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**9.2**	**12.0**	**30.2%**
Network Operating Costs													
Inspections and maintenance	3.2	3.0	3.8	4.0	4.0	4.1	4.1	4.2	4.1	4.1	18.1	20.6	14.1%
Fault repairs and restoration	6.1	5.2	5.5	6.1	6.1	6.0	6.0	6.0	5.9	5.9	29.0	29.8	2.9%
Tree cutting	2.9	2.9	2.6	3.6	8.8	8.8	7.1	7.1	7.1	7.1	20.8	37.2	78.6%
Other Network costs	2.7	2.6	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	12.4	12.0	-3.4%
Total	**14.9**	**13.7**	**14.2**	**16.1**	**21.3**	**21.3**	**19.6**	**19.7**	**19.5**	**19.5**	**80.3**	**99.6**	**24.1%**
RPEs				1.2	1.6	2.0	2.4	3.0	3.4	3.8	2.8	14.6	
Total (Including RPEs)	**14.9**	**13.7**	**14.2**	**17.3**	**22.9**	**23.3**	**22.0**	**22.7**	**22.9**	**23.3**	**83.1**	**114.2**	**37.5%**
Indirect Costs													
Engineering Indirects	14.0	14.6	14.7	15.7	16.0	16.3	16.4	16.4	16.4	16.4	75.0	81.9	9.2%
Network/Investment Support	9.6	9.9	11.0	11.7	11.7	11.7	11.7	11.7	11.8	11.8	53.9	58.7	8.9%
Business Support	22.5	20.2	19.1	19.5	19.6	19.8	19.8	19.9	20.0	20.0	100.9	99.5	-1.4%
Non-operational capex	1.5	2.3	3.5	4.3	3.3	6.3	6.3	3.3	3.3	3.3	14.9	22.5	51.0%
Total	**47.6**	**47.0**	**48.3**	**51.2**	**50.6**	**54.1**	**54.2**	**51.3**	**51.5**	**51.5**	**244.7**	**262.6**	**7.3%**
RPEs				1.0	1.5	2.0	2.5	3.0	3.6	4.3	2.5	15.4	
Total (Including RPEs)	**47.6**	**47.0**	**48.3**	**52.2**	**52.1**	**56.1**	**56.7**	**54.3**	**55.1**	**55.8**	**247.2**	**278.0**	**12.5%**
Total	**77.4**	**82.8**	**93.3**	**110.3**	**114.2**	**121.7**	**119.8**	**116.9**	**115.8**	**115.9**	**478.0**	**590.2**	**23.5%**
Total RPEs				3.0	5.0	6.8	8.7	11.1	12.0	13.3	8.0	51.9	
Total (Including RPEs)	**77.4**	**82.8**	**93.3**	**113.3**	**119.2**	**128.5**	**128.5**	**128.0**	**127.8**	**129.2**	**486.0**	**642.1**	**32.1%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Load related investment													
Customer specific - Demand	9.3	9.8	7.7	11.6	11.1	5.4	5.6	6.2	6.5	6.6	49.4	30.3	-38.8%
Diversions	-0.1	0.0	0.0	0.5	0.6	0.5	0.6	0.5	0.6	0.5	1.0	2.7	172.2%
General reinforcement - P2/6	1.8	4.8	7.2	8.5	5.7	7.8	7.4	7.1	6.5	6.9	28.0	35.7	27.4%
General reinforcement - Fault Levels	0.0	0.0	0.0	1.7	0.1	0.1	0.1	0.1	0.1	0.1	1.8	0.5	-72.2%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**11.0**	**14.6**	**14.9**	**22.3**	**17.5**	**13.8**	**13.7**	**13.9**	**13.7**	**14.1**	**80.3**	**69.2**	**-13.8%**
Customer Contributions													
Customer specific - Demand	24.6	16.0	12.1	10.1	5.6	5.8	6.1	6.4	6.8	7.0	68.5	32.1	-53.1%
Total Load related (Net)	**-13.6**	**-1.5**	**2.8**	**12.2**	**11.9**	**8.0**	**7.6**	**7.5**	**6.9**	**7.1**	**11.8**	**37.1**	**214.4%**
Non Load related investment													
Asset replacement	17.1	21.7	24.2	25.4	24.9	27.9	27.9	27.9	27.9	27.9	113.2	139.5	23.2%
Quality of supply (IIS)	2.2	2.5	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	-100.0%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8	0.0	4.0	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms	0.3	0.3	0.2	0.5	0.5	2.1	2.2	2.2	1.7	1.6	1.8	9.8	433.6%
Environmental	0.1	0.1	2.0	2.3	2.2	1.8	1.8	1.8	1.8	1.8	6.7	9.0	34.1%
Legal & safety	0.0	0.0	0.0	1.9	1.9	3.3	3.3	3.3	3.3	3.3	3.7	16.7	346.3%
Total Non Load related	**19.7**	**24.6**	**28.3**	**30.1**	**29.5**	**35.9**	**36.0**	**36.0**	**35.5**	**35.4**	**132.1**	**179.0**	**35.5%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/015**	**DPCR4**	**DPCR5**	**% Change**
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	1.5	1.5	1.7	1.7	1.7	1.7	1.7	2.9	8.7	195.2%
Environmental													
Visual Amenity	0.0	0.0	0.4	1.4	1.4	1.0	1.0	1.0	1.0	1.0	3.2	5.0	56.3%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.5	4.0	4.0	4.0	4.0	4.0	4.0	4.5	20.0	344.4%

SSE (Hydro) - August FBPQ Narrative

1.84. Real Price Effects. In our August submission we made a high level assessment of the impact of real price effects in future years. We are currently reviewing these assumptions in light of the current economic climate.

1.85. Network Investment - Load related expenditure. In this submission we have input our best current estimate of investment required to meet future demand growth. There is currently, however, a high degree of uncertainty about future demand requirements. We are therefore reviewing our position and will revisit this area in our February 2009 FBPQ submission.

1.86. Network Investment – Non Load related expenditure. During DPCR4 our investment has increased significantly as we addressed resource and materials issues encountered at the beginning of the period. Our current expenditure levels are on a par with those proposed for DCPR5 and therefore anticipate no problems resourcing this programme as we move from DPCR4 to 5. Our Non Load related investment represents the minimum required to effectively maintain the network, continue to deliver our excellent quality of service and meet our environmental obligations.

1.87. Distributed Generation. This continues to be an active area with no sign of decrease. We forecast that the current levels of investment will continue in DPCR5.

1.88. Indirect Costs. Real cost increases have been experienced in indirect costs during the DPCR4 period. Whilst we expect activity volumes to remain relatively steady during DPCR5 our August forecast included above inflation cost increases in a number of indirect cost areas throughout DPCR5. We also plan increased investment to replace essential non operational IT systems in the first part of the next period.

1.89. Indirect Costs – Tree Cutting. Key drivers for increase in expenditure from DPCR4 to 5 relate to ETR 132 resilience tree cutting and enhanced levels of cutting to maintain ESQCR compliance as required by recent legislative changes.

1.90. Memo items – Flooding and Technical losses. Our expenditure in this area is currently under review and will be included within our February 2009 FBPQ submission.

Electricity distribution price control review
Policy paper - supplementary appendices 5 December 2008

SSE (Southern) - August FBPQ Summary Data

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
SSE Southern	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Network Investment													
Load related (gross)	65.1	63.7	93.5	88.7	68.7	83.4	86.3	87.7	78.7	79.8	379.8	415.9	9.5%
Customer contributions	55.6	54.0	58.0	35.5	34.6	36.7	39.9	43.1	43.0	44.5	237.8	207.2	-12.8%
Load related (net)	9.5	9.7	35.5	53.2	34.1	46.7	46.4	44.5	35.7	35.3	142.0	208.7	47.0%
Non load related	46.1	48.1	48.9	63.8	94.3	82.2	82.2	76.3	76.3	76.2	301.3	393.2	30.5%
Total	**55.6**	**57.8**	**84.4**	**117.0**	**128.5**	**128.9**	**128.6**	**120.8**	**112.0**	**111.5**	**443.3**	**601.9**	**35.8%**
RPEs (net)				2.5	5.8	8.0	10.8	13.2	12.5	12.6	8.3	57.1	
Total (Including RPEs)	**55.6**	**57.8**	**84.4**	**119.5**	**134.3**	**136.9**	**139.4**	**134.0**	**124.5**	**124.1**	**451.6**	**659.0**	**45.9%**
Distributed Generation													
Customer specific - Generation	0.5	0.8	0.5	1.2	12.9	5.1	5.2	8.9	17.5	5.7	15.9	42.6	167.8%
Customer contributions	0.5	0.7	0.5	1.1	7.7	4.7	4.8	8.0	16.0	5.1	10.5	38.5	266.1%
Total	**0.0**	**0.1**	**0.0**	**0.1**	**5.2**	**0.5**	**0.5**	**1.0**	**1.6**	**0.7**	**5.4**	**4.1**	**-24.0%**
Network Operating Costs													
Inspections and maintenance	8.5	9.0	12.4	12.4	12.5	12.5	12.4	12.5	12.5	12.5	54.8	62.4	13.9%
Fault repairs and restoration	19.4	24.3	27.8	25.8	25.7	25.7	25.5	25.3	25.2	25.1	123.0	126.8	3.1%
Tree cutting	5.7	5.6	6.9	7.2	15.6	15.6	15.6	12.1	12.1	12.1	41.0	67.5	64.4%
Other Network costs	-0.4	-0.4	-1.1	-1.0	-1.0	-0.3	-1.0	-1.0	-1.0	-1.0	-3.9	-4.3	N/A
Total	**33.3**	**38.4**	**46.0**	**44.4**	**52.8**	**53.5**	**52.5**	**48.9**	**48.8**	**48.7**	**214.9**	**252.4**	**17.5%**
RPEs				1.0	2.2	3.6	4.9	6.3	7.6	9.0	3.2	31.4	
Total (Including RPEs)	**33.3**	**38.4**	**46.0**	**45.4**	**55.0**	**57.1**	**57.4**	**55.2**	**56.4**	**57.7**	**218.1**	**283.8**	**30.1%**
Indirect Costs													
Engineering Indirects	25.0	26.7	29.5	31.1	31.3	32.0	32.0	32.0	32.0	32.0	143.6	160.0	11.4%
Network/Investment Support	22.1	21.9	22.3	23.3	23.5	23.7	23.7	23.7	23.7	23.8	113.1	118.6	4.9%
Business Support	29.9	28.8	29.2	29.8	30.0	30.0	30.1	30.1	30.3	30.3	147.8	150.8	2.1%
Non-operational capex	2.7	13.0	7.5	6.8	5.8	11.8	11.8	8.8	8.8	8.8	35.8	50.0	39.6%
Total	**79.7**	**90.5**	**88.5**	**91.0**	**90.6**	**97.5**	**97.6**	**94.6**	**94.8**	**94.9**	**440.3**	**479.4**	**8.9%**
RPEs				2.1	3.1	4.1	5.1	6.3	7.5	8.7	5.2	31.7	
Total (Including RPEs)	**79.7**	**90.5**	**88.5**	**93.1**	**93.7**	**101.6**	**102.7**	**100.9**	**102.3**	**103.6**	**445.5**	**511.1**	**14.7%**
Total	**168.6**	**186.8**	**218.9**	**252.5**	**277.1**	**280.4**	**279.2**	**265.3**	**257.2**	**255.8**	**1103.9**	**1337.8**	**21.2%**
Total RPEs				5.6	11.1	15.7	20.8	25.8	27.6	30.3	16.7	120.2	
Total (Including RPEs)	**168.6**	**186.8**	**218.9**	**258.1**	**288.2**	**296.1**	**300.0**	**291.1**	**284.8**	**286.1**	**1120.6**	**1458.0**	**30.1%**

Network Investment - by Building Block

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Load related investment													
Customer specific - Demand	41.6	34.2	40.7	26.8	34.3	29.9	32.3	33.7	35.0	36.3	177.5	167.2	-5.8%
Diversions	-0.9	0.0	0.0	2.8	3.0	2.8	2.9	2.9	3.0	2.9	4.9	14.5	193.8%
General reinforcement - P2/6	24.1	29.3	52.8	57.5	29.9	49.7	49.7	49.7	39.7	39.6	193.6	228.4	18.0%
General reinforcement - Fault Levels	0.3	0.3	0.0	1.6	1.5	1.0	1.4	1.4	1.0	1.0	3.7	5.8	56.8%
DNO discretionary	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total Load related (Gross)	**65.1**	**63.7**	**93.5**	**88.7**	**68.7**	**83.4**	**86.3**	**87.7**	**78.7**	**79.8**	**379.8**	**415.9**	**9.5%**
Customer Contributions													
Customer specific - Demand	55.6	54.0	58.0	35.5	34.6	36.7	39.9	43.1	43.0	44.5	237.8	207.2	-12.8%
Total Load related (Net)	**9.5**	**9.7**	**35.5**	**53.2**	**34.1**	**46.7**	**46.4**	**44.5**	**35.7**	**35.3**	**142.0**	**208.7**	**47.0%**
Non Load related investment													
Asset replacement	42.0	43.2	44.2	56.5	83.9	67.8	67.8	62.0	62.0	62.0	269.8	321.6	19.2%
Quality of supply (IIS)	3.8	4.1	3.1	1.7	1.7	3.6	3.6	3.5	3.5	3.5	14.3	17.7	23.4%
Quality of supply (non IIS)	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8	0.0	4.0	N/A
Major system risks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms	0.2	0.1	0.2	0.7	0.7	3.8	3.8	3.8	3.8	3.7	1.9	18.9	884.3%
Environmental	0.1	0.7	1.4	3.4	6.5	3.3	3.3	3.3	3.3	3.3	12.1	16.5	35.9%
Legal & safety	0.0	0.0	0.0	1.5	1.5	2.9	2.9	2.9	2.9	2.9	3.1	14.5	371.3%
Total Non Load related	**46.1**	**48.1**	**48.9**	**63.8**	**94.3**	**82.2**	**82.2**	**76.3**	**76.3**	**76.2**	**301.3**	**393.2**	**30.5%**

Memo Items - Further breakdown of Building Blocks

£m (07/08 Prices)	Actuals			Forecast		DPCR5 Forecast					Totals		
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/015	DPCR4	DPCR5	% Change
Major system risks													
Flooding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
HILP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Operational IT and telecoms													
BT21C			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Legal & safety													
ESQCR	0.0	0.0	0.0	0.8	0.8	0.6	0.6	0.6	0.6	0.6	1.7	3.0	79.5%
Environmental													
Visual Amenity	0.0	0.4	1.2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	3.6	5.0	38.3%
Technical Losses				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Tree cutting													
ETR-132			0.0	0.6	2.8	2.8	2.8	2.8	2.8	2.8	3.4	14.0	311.8%

SSE (Southern) - August FBPQ Narrative

1.91. Real Price Effects. In our August submission we made a high level assessment of the impact of real price effects in future years. We are currently reviewing these assumptions in light of the current economic climate.

1.92. Network Investment - Load related expenditure. In this submission we have input our best current estimate of investment required to meet future demand growth. There is currently, however, a high degree of uncertainty about future demand requirements. We are therefore reviewing our position and will revisit this area in our February 2009 FBPQ submission.

1.93. Network Investment – Non Load related expenditure. During DPCR4 our investment has increased significantly as we addressed resource and materials issues encountered at the beginning of the period. Our current expenditure levels are on a par with those proposed for DCPR5 and therefore anticipate no problems resourcing this programme as we move from DPCR4 to 5. Our Non Load related investment represents the minimum required to effectively maintain the network, continue to deliver our excellent quality of service and meet our environmental obligations.

1.94. Distributed Generation. This continues to be an active area with no sign of decrease. We forecast that the current levels of investment will continue in DPCR5.

1.95. Indirect Costs. Real cost increases have been experienced in indirect costs during the DPCR4 period. Whilst we expect activity volumes to remain relatively steady during DPCR5 our August forecast included above inflation cost increases in a number of indirect cost areas throughout DPCR5. We also plan increased investment to replace essential non operational IT systems in the first part of the next period.

1.96. Indirect Costs – Tree Cutting. Key drivers for increase in expenditure from DPCR4 to 5 relate to ETR 132 resilience tree cutting and enhanced levels of cutting to maintain ESQCR compliance as required by recent legislative changes.

1.97. Memo items – Flooding and Technical losses. Our expenditure in this area is currently under review and will be included within our February 2009 FBPQ submission.