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Electricity Distribution Price Control Review
Initial consultation document - 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, 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 customers. We set the total revenues that each DNO can collect from customers at a level that allows an efficient company to finance their business. We set commercial incentives to improve their efficiency and quality of service. We do this by setting a price control every five years.

The current price control expires on 31 March 2010 and this document is the beginning of the next Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. We set out our initial thoughts on the issues we have to address, the methodologies we might use to set revenues and the process we intend to follow. One of the key themes for this document is what further steps we need to take to allow the DNOs to play their part in helping us to move to a lower carbon economy.

We would welcome comments and views on the issues raised by the review by Monday 23 June 2008.

This document contains the appendices for the initial consultation document.

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Context

Ofgem's principal objective is to protect the interests of consumers. For the monopoly energy networks, this means regulating the charges they pay and the quality of service that they receive. We regulate the 14 distribution network operators (DNOs) by setting a price control every five years. The price control 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 improve their efficiency 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 document is the initial consultation in the process and follows on from the open letter consultation published in May 2007. We will publish a policy paper in December 2008 and will publish initial proposals in June/July 2009 followed by final proposals in November/December 2009.

This document focuses on three key themes; the environment, customers and networks. We intend to use these themes throughout DPCR5. We will look to encourage DNOs to take a full role in helping to tackle climate change, to balance quality of service to customers with costs of delivery and to provide security of supply at reasonable cost. DPCR5 will require the DNOs to play a more active role in setting business strategies whilst taking into account the need of their customers.

Associated Documents

- Electricity Distribution Price Control Review - Initial consultation document (32/08)

- Approval of Redress Schemes in the Energy Sector (247/07) http://www.ofgem.gov.uk/Markets/RetMkts/Compl/ConsRep/Documents1/Consultation%20criteria%20for%20approval%20of%20redress%20schemes%2024707.pdf

- Complaint Handling standards (272/07) http://www.ofgem.gov.uk/Markets/RetMkts/Compl/ConsRep/Documents1/Complaint%20Handling%20Standards%20Consultation.pdf

- Consumer First research for DPCR5 – cover letter http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=127&refer=Networks/ElecDist/QualofServ

- Distributed Energy – Initial proposals for more flexible market and licensing arrangements (295/07) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=160&refer=Networks/ElecDist/Policy/DistGen

- Distribution Price Control Review – Final Proposals (265/04) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=51&refer=Networks/ElecDist/PriceCntrls/DPCR4

- DPCR5 - looking ahead an initial consultation letter (119/07) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/ElecDist/PriceCntrls/DPCR5

- Electricity Distribution Cost Review 2006-07 (289/07) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=22&refer=Networks/ElecDist/PriceCntrls/CostRep

- Gas Distribution Price Control Review Final Proposals Consultation Document (285/07) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=362&refer=Networks/GasDistr/GDPCR7-13

- Review of Competition in Gas and Electricity Connections Proposals Document (26/07) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=160&refer=Networks/Connectns/CompinConn

- Transmission Price Control Review: Final Proposals (206/06) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=191&refer=Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses

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Appendix 5 – Responses to open consultation letter

1.1. In May 2007 we wrote to distributors, customer groups, distributed generators, suppliers, connection providers and other parties to invite views on the general approach and key issues for the next price control review[1].

1.2. We received 15 non-confidential responses[2] from the following organisations:

- ABB
- Beama
- CE Electric UK (CE)
- Centrica
- Country Land and Business Association (CLA)
- EDF Energy Networks (EDFE)
- energywatch
- Energy Networks Association (ENA)
- E.on (Central Networks - CN)
- Friends of the Lake District
- RWE
- Scottish and Southern Energy (SSE)
- ScottishPower (SP) Transmission and Distribution
- United Utilities (UU)
- Western Power Distribution (WPD)

1.3. The letter set out our preliminary thoughts in advance of DPCR5, and invited views on the following:

- The key strategic issues for DPCR5
- What changes should be considered to the roles and responsibilities/obligations of distribution businesses?
- How to build on or make best use of incentives in DPCR4 and the developments since?
- How can we simplify and refocus the incentive package to address future requirements?
- The process and timetable for the review?

1.4. This document summarises the responses to the questions above.

[1] DPCR5 - looking ahead an initial consultation letter (119/07)

[2] Non-confidential responses are published on the Ofgem website: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/ElecDist/PriceCntrls/DPCR5

Have we captured the key strategic issues?

1.5. In the letter we set out the context in which DPCR5 will take place, noting the evolution in energy policy reflected by the Energy White Paper, the EU agreement on a binding 20 per cent renewable energy target and the Stern Review. We mentioned the work that Ofgem has carried out to date, and will continue to develop, on issues such as distributed generation (DG), long-term scenarios and carbon costing.

1.6. Our objectives for DPCR5 will flow from our statutory duties; our primary duty to protect the interests of current and future consumers, and our requirements to facilitate sustainable development, promote secure supplies and good customer service, and ensure that networks and network operators respond to new challenges they will face.

Respondents' views

Regulatory approach

1.7. The majority of responses expressed support for Ofgem's high level principles. Many respondents expressed support for a continuation of the current RPI-X regulation within a five year framework. One DNO commented that this would provide a stable market and deliver major investment for infrastructure replacement and connection of DG; regulatory stability and consistency was a priority for many respondents. A supplier would welcome a move towards longer price control review periods once 'inherent instabilities' are addressed, such as DG, renewables and smart metering. It also suggested that now would be excellent opportunity to consider the review process from first principles, including the possibility of an alternative model.

1.8. An industry group suggested that the focus of the review on the economic business model of DNOs does not address major supply chain challenges. It recommends a 'total system architecture' that would include all forms of generation, transmission and distribution networks, and demand side participation.

1.9. A DNO sees the forthcoming review as a balancing act between bold action on environment and sustainability, and also maintaining an evolutionary regulatory approach that continues to provide a high degree of regulatory commitment.

1.10. A supplier expressed a desire to review the use of the weighted average cost of capital (WACC) model as part of the price control review. Given that it was intended for a competitive market situation, it contends that applying this approach to monopoly businesses may result in inherent differences generating distortions or overestimates of model inputs and outputs.

1.11. A DNO recommended that the primary focus should be to ensure that all aspects of distribution businesses are fully funded. However, a supplier expressed concerns that network operators have an 'over generous' allowed rate of return, which may lead to shareholder profits at the expense of customers.

1.12. An industry group suggested that Ofgem should initiate discussions on proposals for financing and determining capital cost for DNOs.

1.13. One DNO commented that the cost of capital decision would be pivotal in the review as companies need to attract continued investment and mitigate increasing risk. Two other DNOs echoed this call for an appropriate cost of capital, and one suggested that appropriate incentive mechanisms would provide a stable market and deliver major investment for infrastructure replacement and connection of DG.

1.14. Many responses from DNOs and other respondents advocated a continuation of incentive regulation, though it was acknowledged that incentives may need to adapt to changing priorities and energy policy objectives. A supplier noted the importance of balancing incentives for operating and capital expenditure.

1.15. A DNO commented that an enduring technical and commercial framework is needed that does not weaken incentives through undue complexity, though it added that technical challenges of generator connections are less challenging than properly defining the role and behaviours of DNOs.

1.16. An industry group welcomed in principle the reduced workload and timescales that Ofgem's 'lighter touch' approach may yield, and sought greater clarity on the details and implications of this approach given the number of new challenges for this review.

Customers

1.17. The consumer representative highlighted the need to improve the interface between customers and DNOs; it is particularly concerned about complaints that require energy sector knowledge when it disbands in 2008. Complaints handling and customer service should link back to the price control.

1.18. One DNO considers that the review could consider how local wishes are reconciled with government policy.

1.19. Another DNO called for an effective and equitable competition in connections framework in the interests of the end consumer.

Environmental and sustainability issues

1.20. Respondents noted that environmental issues are becoming an increasingly important component for customer choice and value. A DNO suggested customers' views on environmental and sustainability issues would develop significantly during the next price control period.

1.21. Several DNOs would welcome a review that addresses the government's energy goals and follows government policy on encouraging renewables investment, actively promoting CHP and energy efficiency. One DNO added that uncertainty exists around how much renewable generation will emerge, and what voltage it would connect at. Equally it is uncertain whether demand will fall in response to carbon reduction measures, and what the future of the transport market is.

1.22. Several respondents consider DPCR5 to be an opportunity to challenge the status quo of meeting demand economically. They suggested work in the areas of active demand management, facilitation of micro-generation and renewables. Incentives offered for enabling sustainable energy should make such projects more attractive than 'business as usual'.

1.23. A lobby group concerned with visual amenities within the Lake District National Park would like the undergrounding allowance to continue into the DPCR5 price control. It also called for other issues, such as Ofgem's financial caps and restrictions on lines that are either less than 15 years old or already earmarked for conventional renewal, to be addressed.

1.24. An industry group expressed concern that the urgency of action on DG and demand-side participation is missing from the proposed schedule.

Long term scenarios

1.25. Respondents expressed support for Ofgem's work on long term scenarios and suggested that such planning should feed into the DPCR5 consultation process. One DNO commented that long term scenarios are vital tools to determine the roles and responsibilities of distributors. It suggested that the DNO could either remain as a commercially passive organisation, primarily to support demand, or become commercially active developing the network to encourage the flow of low-carbon energy and drive changes in usage, primarily to achieve a low carbon economy.

1.26. One DNO suggested that the timetable for long term scenarios could be more aggressive.

1.27. An industry group commented on the importance of balancing short term cost reductions with long term sustainable network solutions. It suggested that the planning horizon should be longer than five years. It agreed with proposals for a longer term perspective, particularly long term network scenarios, and suggested that DPCR5 should help to move the industry away from 'doing the same things more efficiently' towards 'a new operational and regulatory framework'.

Transparency

1.28. A supplier commented that information transparency is a key issue for suppliers, which consider that they have insufficient information to challenge DNOs' assertions or evaluate proposals.

1.29. Another supplier would like further consideration to be given to transparency, predictability and accuracy of the review where allowed revenue is concerned. In addition, further development of the under-pinning methodology is needed to attempt to remove wider variations in DNOs' recovery positions that has been evident in 2007.

Security of supply

1.30. A DNO expressed satisfaction with the level of investment to provide for safe and continuing energy supplies sufficiently protected from weather extremes.

1.31. Another DNO added that BERR may wish to provide a national steer on flood protection.

What changes should be considered to the roles and responsibilities/obligations of distribution businesses?

1.32. In our letter we asked whether we should add or substitute certain responsibilities and obligations, for example by asking distribution companies to assess their own carbon footprints or intervening in other parts of the energy sector, such as smart metering.

1.33. We also asked for views on the implications of the growth of distributed generation on industry structures and relationships, such as the interface between transmission and distribution networks, ownership unbundling of network operators from generators and suppliers, and the possibility of competitive tendering of some functions.

Respondents' views

Low carbon agenda

1.34. Several DNOs welcomed the possibility of measuring their carbon emissions. One called for a more explicit approach by proposing a modification to Section 9 of the 1989 Electricity Act to enshrine the duty to reduce greenhouse gas emissions (Section 26 of the 2006 Climate Change and Sustainable Energy Act). Another DNO suggested that a standard way of defining a carbon footprint should be determined before DNOs are incentivised to reduce their carbon footprint.

1.35. One DNO described three potential roles for distributors: business as usual; environmentally aware (higher-value losses, new incentive for SF6 reduction, extended UoS pricing signals); driving a low carbon economy (redesigning a network around distributed energy sources rather than demand, and driving customer and network energy efficiency).

Expansion of the role of distribution companies

1.36. The majority of responses welcomed progress towards active network management, particularly through smart metering, energy efficiency and growth of DG. A stakeholder group suggested that regulation could enable distributors to become energy service companies, in parallel with suppliers. One DNO added that it welcomes an expanded role for distributors provided there are clear advantages to doing so, and where adding value is fairly rewarded. Another DNO called for clarity from Ofgem on required outputs from the regulatory contract given the potential for an expanded role for distribution businesses.

1.37. The consumer representative suggested that Ofgem could identify how DNOs can efficiently manage the transition to increasing DG connections, but warned that consumers would only be willing to pay for improvements that are real and quantified. Transparent business plans and regional workshops were suggested as first steps, in addition to ensuring that data is recorded correctly and consistently.

1.38. A stakeholder group suggested that smart metering (particularly net metering) could help consumers to control their energy use, and encouraged distributors to deliver a framework to enable DG connections to flourish. Several DNOs envisaged that they would play a key role in helping to achieve government targets by delivering smart metering, connecting DG and spreading customers' contributions to the cost of energy efficiency measures.

1.39. Several respondents suggested that demand side participation by residential customers is possible through export reward for micro-generation and demand-side restraint. A DNO suggested that DNOs could provide power line carrier communication infrastructure.

1.40. A stakeholder group commented that a move towards active networks may lead to new market entrants such as aggregators for micro-generation. It indicated that changes to the five year review process may be required to allow for technical functionality needed to develop of service-based rather than commodity-based distributors. However, a DNO considers that no major changes are required, and suggests that the regulatory framework should encourage and enable DNOs to take the necessary actions.

1.41. One DNO noted that distribution companies should continue to play a role in revenue protection and urgent metering services and suggested that this could be expanded. Another DNO added that a programme for rectification of open-wire low voltage overhead lines in proximity to buildings is needed.

Unbundling

1.42. A supplier expressed support for the enduring split between DNOs and suppliers. However, two DNOs commented that asset ownership unbundling is not a legal requirement at distribution level in the UK so should remain outside the proper scope of DPCR5.

How can we build on or make best use of the range of developments and incentives set out in paragraph 10?

1.43. In our letter we outlined some of the recent developments in our approach that have moved the focus away from the five year expenditure allowances, such as the sliding scale approach and long term scenario planning. We will look to the companies to explain and quantify what they intend to deliver through their plans and how they intend to resource delivery of the plans into the future, including how they will address the availability of skilled staff at all levels of their organisations, building on the welcome initiatives already underway.

Respondents' views

Long term planning

1.44. Respondents expressed support for long term planning, and welcomed Ofgem's long term scenarios work, which they saw as necessary to facilitate government energy policy and a sustainable energy system.

1.45. One DNO commented that the five year price control review remains an appropriate mechanism provided that it is based on longer-run assumptions that reflect asset life.

1.46. Another DNO suggested flexible revenue drivers and logging up mechanisms to deal with uncertainty, to reduce reliance on fixed allowances and provide flexibility to deal with credible scenarios. Another DNO expressed support for a review of historic approaches to projecting expenditure requirements.

Ofgem's approach to investment expenditure

1.47. Several DNOs commented that they would prefer a system based on obligations, incentives and cost benchmarking to prescriptive rules governing how DNO businesses are run, and expressed support for the reducing emphasis on five year allowances, and Ofgem's moves to take a more arm's length approach to regulation.

1.48. One DNO sought assurance from Ofgem that 'intrusion' into GDN investment expenditure was an exceptional event, and indicated that it would not welcome attempts to micro-manage its distribution business.

Skills shortages

1.49. An industry group pointed to the endemic engineering skills shortage that requires recognition and funding to achieve government goals.

1.50. A rural interest group suggested that RPI-X regulation has led to the deskilling of distribution companies, and that the new approach should take account of the professional and engineering costs of both secure supplies and sustainable development.

Allowances and incentives

1.51. A DNO agreed with Ofgem’s desire for a better integration of capex and opex allowances.

1.52. One DNO welcomed the development of the RRP and its capacity to provide robust data, which in its opinion reduces regulatory risk and the likelihood of erroneous cost allowance assessments. It suggested a full consultation exercise to develop improved econometric models. A supplier called for transparent arrangements for initiatives, and a clear reporting framework from Ofgem with cost/benefit information and details of further required investment. It argued that impact assessments should be published in advance of significant capex so that customers and interested parties can assess benefit and judge that they are satisfied with the value of the expenditure.

1.53. A supplier suggested that assets should be recovered over their useful life, rather than through allowances paid up front. A DNO would welcome a 'common language' to define whole-life costing and also to ensure that base figures are comparable, claiming that recent RRP data shows many discrepancies. Another DNO is keen for cost assessment to include the building blocks for the cost of capital. Due to asset longevity, long term funding requires stability rather than undue focus on short-term rates in volatile debt markets.

1.54. A DNO expressed support for a reduced emphasis on five year allowances. Although Ofgem encourages DNOs to adopt robust and accredited asset management arrangements, the DNO claims that we rely heavily on 'opaque and relatively simplistic' forecasts during price control reviews.

1.55. An industry group expressed concerns about imposing ex-post penalties for non-delivery or failure to achieve standards.

1.56. The consumer representative commented that cost reporting is most beneficial when the presentation of information is usable, accessible and understandable, and repeated this advice with respect to licence wording.

1.57. One DNO called for a meaningful and clear basis for comparison in the review, and noted that little progress had been made on comparative efficiency techniques. It stressed that data must be consistent across all DNOs.

How can we simplify and refocus the incentive package to address future requirements?

1.58. In the letter we referred to the new incentives and adjustment mechanisms for DCPR4, for example in relation to innovation, customer service and environmental matters. Whilst we perceive that these have had a positive impact on focusing attention and effort in the areas specifically targeted, we proposed to consider whether all of the different mechanisms are needed.

1.59. We noted the introduction of our annual sustainable development report, which may provide a useful tool with which to review and develop the incentive package, and also the introduction of the customer service reward scheme, with a reward of up to £1 million a year to promote best practice in meeting the needs of vulnerable customers.

1.60. We also acknowledged that incentive regulation creates the risk of focusing attention on targeted area to the detriment of others, and suggested that one approach to address this is through one-off adjustments to revenue as part of a price control review. We have done this in the past to reward one group in recognition of its leadership on quality of service, and have indicated that we will consider adjustments at the coming review in respect of DG and the issues set out in our proposals paper[3].

Respondents' views

Incentive regulation

1.61. Respondents indicated strong support for the continuation of incentive regulation to deliver the objectives of DPCR5, particularly with the use of symmetric incentives. One DNO respondent considered that incentives should be geared towards process inefficiencies. One DNO expected to see a widening of performance incentives rather than a reduction in the reach of targeted incentives. Another DNO considered that mechanistic revenue drivers have served the industry well and noted that better regulation would not necessarily mean fewer mechanistic revenue drivers. Another DNO considered that there was no need to simplify the incentive framework.

[3] Review of Competition in Gas and Electricity Connections, Proposals Document (26/07)

IIS targets

1.62. Most DNOs and one customer representative respondent supported setting IIS targets and rewards early in DPCR5 to help with planning. One DNO highlighted the need to address the mismatch between the timetable for determining incentive rates and capex. Another DNO considered that targets should not be set until the full price control package is finalised. Another DNO indicated reluctance to accept early targets without an understanding of the longer term framework and treatment of exceptional events.

1.63. One DNO suggested that CI and CML incentive rates should be equalised to ensure a more balanced scheme and equitable treatment of DNOs outperforming the CI benchmarks.

1.64. One DNO suggested that IIS targets must accommodate the law of diminishing returns that will apply to further QoS related investment. Another DNO commented that DPCR5 IIS targets must take account of the potential for increased planned work and the subsequent outage risk and reduced security.

1.65. Another DNO was concerned that any incentive on short interruptions would negate the benefits of automation and discourage continued investment in this area.

Discretionary schemes

1.66. There was some support amongst DNOs for the continuation of the discretionary reward scheme for social issues and acknowledgement that the current scheme has driven behavioural change. One DNO commented that the awards scheme for the current process could be more robust and transparent. The majority of DNO respondents considered that an extension of the discretionary scheme would offer a weak incentive to improve performance. One DNO considered that such a scheme may not be in the best interests of customers because rewards are uncertain and investments less justifiable.

1.67. Another DNO commented that companies should not be penalised through a discretionary scheme, but if regulatory intervention is necessary, it should be done through a formal route. Another DNO thought that there should be no scope for subjective judgements by Ofgem as part of an incentive.

Sustainability/Environmental issues

1.68. There was much focus on the sustainability and environmental agenda in most responses. The majority of DNO respondents supported a carbon footprint incentive on the companies' operations. Suggested features of such a scheme include:

- reducing the DNO's own consumption of electricity (offices and substations),

- reducing fossil fuel usage from company vehicles and mobile plant,
- electrical losses optimisation,
- power factor management, and
- SF6 management.

1.69. One DNO suggested that a working group should be set up to tackle this issue.

1.70. Some DNOs suggested that performance based rewards could be extended to other areas where outcomes are measurable such as SF6 reduction and replacement of fluid filled cables. One DNO suggested that a replacement strategy for fluid filled cables could focus on cable condition and circuit specific environmental risk.

Undergrounding in AONBs and National Parks

1.71. A few respondents mentioned the undergrounding scheme and were keen for its continuation into DPCR5. One DNO respondent welcomed willingness to pay research on the continuation of funding for this scheme and suggests that the scheme should be extended in size, geographical coverage and function to address noise as well as amenity.

1.72. One lobby group respondent raised concerns with the financial caps set by Ofgem for undergrounding. The same respondent also suggested that the long lead times for undergrounding projects justified reaching an early agreement to extend the scheme into DPCR5 (as was the case with IFI).

Consumer research

1.73. Most respondents welcomed the timing and degree of stakeholder involvement for the DPCR5 consumer research. DNO respondents mentioned a number of issues that they would like the research to address, including:

- how the views of consumers as revealed by the research could be merged with the views of citizens as represented by government energy policy,
- the conflict between reducing costs and maintaining sustainable networks,
- customer preferences regarding low carbon and sustainability issues bearing in mind how opinions could have changed by 2015, and
- the statistical robustness of results that can be used as an output for the price review.

1.74. The consumer representative respondent predicts that customers will only be willing to pay for improvements in service where they are real and quantifiable, not elements of service that any customer facing organisation should already provide.

Guaranteed standards

1.75. One DNO respondent would like the potential uncapped liability of GS payments during a major event to be reviewed for DPCR5.

1.76. The consumer representative respondent considers that complaint handling will be a key concern for DPCR5 and that Ofgem should implement a performance standard in this area relating back to the price control. The same respondent also considered that there was a need to audit GS returns to ensure accuracy and consistency.

ESQCR

1.77. One DNO highlighted that the tree trimming obligation was not a key issue at DPCR4, but will have an impact on current levels of expenditure and will require expenditure during DPCR5. Another DNO identified that the approach to open-wire low voltage overhead lines in proximity to buildings will be an area of concern at DPCR5.

Network resilience

1.78. One DNO considered that two key areas of concern are the design loadings for overhead lines and designs of substations to mitigate emerging future flood risk.

1.79. According to one DNO an important area of network resilience is reinforcing rural systems or eliminating small section conductor to bring performance up to national standards.

Worst served customers

1.80. One DNO considered that increased focus on worst served customers is unlikely to deliver cost/benefit ratios comparable with investments aimed at maximising overall security and availability.

1.81. Another DNO suggested that worst served customers may be a performance based area to incentivise.

Do you agree with the suggested process and timetable set out, both for work in 2007 and for the review? What should we do differently?

1.82. In our letter we proposed to commission research, as part of our Consumer First project and to inform the price review, into consumer views on a range of issues of interest. We also indicated that we intended to build on the efforts made by electricity distribution companies to engage more with their stakeholders. Distributors could consult stakeholders on choices within their business plans with the help of more transparent business plans and regional workshops. In addition, we indicated that we intend to continue several aspects of the process from the last review, including use of an Authority committee at key stages.

1.83. We also outlined plans for 2007, including work on cost reporting, charging and connections issues, follow-up work from the Financing Networks project and a review of the electricity distribution licence. In addition, we signalled our intention to review the new initiatives introduced in DPCR4. Finally, we asked for views on the merits of setting some aspects of the price control early, such as quality of service targets, given that we recently extended the IFI on this basis.

Loss of the September update

1.84. Respondents expressed widespread concern about the unduly long gap between initial and final proposals, brought about by the loss of the September update paper. One DNO commented that thinking develops quickly during the six months between initial and final proposals, which means that final material would be harder to understand without an interim step.

1.85. Another DNO suggested a formal quantified published statement at the September 2009 checkpoint, and another DNO called for some form of iterative consultation, whether public or private. Another DNO added that the loss of three major consultation papers, and the September update in particular, would reduce clarity and information to stakeholders.

1.86. However, a supplier expressed support for longer consultation periods and reduction in formal consultation, provided that participants can engage more effectively with the process.

Engagement with consumers and stakeholders

1.87. Respondents expressed strong support for the proposals for better engagement with consumers and stakeholders. A DNO commented that stakeholder engagement should be meaningful to the review process, and be at a level consistent to the scale of the debate. A supplier added that customer consultations should be sharp and focused, and workshops should be influential, being able to develop specific proposals that DNOs must recognise.

1.88. An industry group considered that the customer survey should be widened, and better customer information should be provided, especially regarding the vision of a future "SmartGrid". It added that it welcomed the move for the review to be more user-friendly, and would like to be involved in workshops.

1.89. A DNO commented that care and expertise will be needed to understand customers' willingness to pay for environmental and sustainability projects. Another DNO added that consumer research should be carried out at an early stage, and should be designed to ensure it is statistically robust so that the responses can be used as outputs in the price control review.

1.90. SSE supports Ofgem's proposals to better engage with stakeholders, feed outputs from stakeholder consultations into business plans and supports the use of the Authority committee at key stages.

Work for early completion

1.91. A DNO suggested that incentive rewards should be set early in the DPCR5 process to provide clear signals to customers.

1.92. A supplier would welcome better industry dialogue to allow time for ground rules and confidence-building, and for fuller discussions. It added that discussions were fettered by regulatory steers too early in the process.

1.93. A DNO commented that the submission of draft forecasts in March 2009 would be too late and would not provide sufficient time for analysis and discussion. It suggested that the submission deadline should move back to November 2008. In addition it would like work to begin as early as possible on licence modifications needed to implement new price controls. It suggests that drafting should begin once initial proposals are finalised and draft modifications should be published with final proposals.

1.94. Another DNO warned that Ofgem's decision on the cost of capital must not be left until the last minute. In its opinion this would be inappropriate for such a fundamental component, inconsistent with better regulation principles and by extension Ofgem's principle objective to protect consumer interests.

Use of an Authority committee

1.95. Two DNOs welcomed Ofgem's intention to use the Authority committee, one commenting that it would help DNOs and Ofgem to develop a shared understanding of how customers' needs can be met through price control incentive systems and funding arrangements.

Appendix 6 - Costs and outputs

Introduction

1.1. This appendix sets out some further technical detail on how we intend to assess costs and associated outputs as part of DPCR5. It builds on the discussion in Chapter four. It covers the following:

- the key objectives of the cost assessment work,
- background on the approach we used for the cost assessment work at the last price control review,
- the work that has been carried out to develop more robust data through annual cost reporting,
- our proposed approach to assessing costs for this price control, and
- the development of cost incentives.

1.2. Our key aims for the cost and output assessment work in this price control review include:

- using the annual regulatory reporting pack (RRP) data to carry out improved benchmarking and modelling work to assess costs,
- to give the DNOs more opportunity to come forward with their own business strategies and assumptions taking into account the longer term development of their networks and the needs and aspirations of local stakeholders, and
- developing greater clarity on the outputs that the networks should deliver.

1.3. The key dates for the DNOs to submit their business plan information are set out in the table below.

Table 1 - Dates for submission of forecast business plan questionnaire (FBPQ) information

April - August 2008	DNOs develop high level business plans informed by stakeholders where possible
15 August 2008	DNOs submit high level business plans in building block format
September - October 2008	High-level plans discussed as part of the annual cost visits
October 2008	Ofgem to publish further details on requirements for detailed Plans and form of the IQI incentive
23 January 2009	DNOs submit detailed plans

Background

Approach to the cost assessment work as part of DPCR4

1.4. In DPCR4, we categorised the DNOs' costs into five main areas:

- operating costs including total fault costs and non-operational capex (opex),
- capital expenditure (capex),
- financial costs such as pensions and taxation,
- pass-through costs, and
- excluded services.

1.5. We used a combination of internal resources and consultants to assess each category of costs and to set allowances for both opex and capex.

1.6. Ofgem and its consultants carried out several visits to each of the DNO groups to discuss the historical and forecast business plan questionnaires and their detailed methods for forecasting investment requirements. Ofgem also set up working groups for the discussion of cost assessment and capex modelling.

1.7. At DPCR4 pass-through costs included:

- transmission exit charges,
- charges from other licensed distributors covered by price controls (wheeling charges),
- variations in network business rates and Ofgem licence fees from the level assumed in setting the price control,
- the benefit of any subsidy for areas with high distribution costs, and
- certain company specific items such as the costs of wholesale electricity balancing in Scotland.

1.8. We will consider the appropriate treatment of these costs as part of DPCR5. Financial costs and excluded services are discussed in chapter five, financial issues.

Operating Costs

1.9. The main source of cost information during DPCR4 was the Historical business plan questionnaires (HBPQs) submitted by the DNOs in September 2003. Upon submission, Ofgem devoted considerable time and resources to understand the data that had been submitted and normalise that data to bring it onto a consistent basis across the 14 DNOs.

1.10. Although the HBPQ data covered the years 2000-2001 to 2002-2003, and for some data tables even earlier than that, it was decided very early during the analysis carried out for DPCR4 to concentrate on the 2002-2003 financial year as the base year for the comparative efficiency work.

1.11. It soon became apparent to us that the HBPQ data was not sufficiently robust at an activity level to generate robust enough results from a bottom-up approach to benchmarking operating costs. We primarily relied on top-down regressions for benchmarking those costs.

1.12. We made a number of adjustments to normalise the data, including:

- removal of atypical and one-off costs for separate consideration,
- removal of related party margins,
- removal of insurance costs,
- removal of lane rental/congestion charges for separate consideration,
- removal of pension costs for separate consideration,
- adjustments for regional factors,
- adjustments to address differing capitalisation policies, and
- removal of research and development costs.

1.13. We applied adjustments for regional factors to the costs of two DNOs; EDFE LPN for higher labour costs in London and the density of the network and SSE Hydro for additional costs relating to the sparsity of the network.

1.14. We benchmarked these costs across DNOs using corrected ordinary least squares (COLS) regressions, as we had insufficient data points to conduct alternative methods such as data envelope analysis (DEA). We investigated these approaches but the results were unsatisfactory given data availability.

1.15. We used a composite scale variable (CSV) that combined customer numbers, units distributed and network length as the independent variable in the regressions. This was a development of the approach used in the previous price control (DPCR3).

$$\textbf{CSV} = \textbf{Network Length}^{(0.5)} \times \textbf{Customer Numbers}^{(0.25)} \times \textbf{Units Distributed}^{(0.25)}$$

1.16. We set the benchmarks for the DNOs at the upper quartile level of efficiency.

1.17. We carried out regressions on three bases. The primary regression used all 14 DNOs as separate data points and regressed normalised controllable costs plus total fault costs on the CSV. A second version of the regression used the data for the nine company groups in place on 1 April 2002, which allowed consideration of the impact of mergers. Finally we carried out a regression of total costs, which allowed for interactions between opex and capex.

1.18. The starting point for the opex allowances was the highest predicted amount from either the results from primary regression or from taking an average across the results generated from all three regressions.

1.19. We then applied a number of further adjustments to determine the opex allowances for each DNO:

- we assumed that DNOs that had not merged with another DNO at the start of 2002-03 would move only halfway to the upper quartile by 2004-05. We assumed that the remaining gap would be closed by the fifth year after a merger or the start of the price control,
- we applied an ongoing productivity saving of 1.5 per cent per annum. This was based on business plan submissions from the DNOs and Total Factor Productivity analysis carried out by our consultants, CEPA, and
- we made additional allowances for tree cutting and quality of service improvements.

Capital Investment

1.20. PB Power advised Ofgem both on historical and forecast investment. They developed models for both load related expenditure (LRE) and non load related expenditure (NLRE) to assess the DNOs' forecasts.

1.21. PB Power assessed LRE requirements using the key drivers of growth in customer numbers and units distributed. They carried out separate modelling based on each of these drivers as well as combining them. They examined historical and company forecast trends in customer and demand growth. PB Power made adjustments to forecasts based on extrapolation of historical data and analysis of wider economic trends.

1.22. PB Power's NLRE modelling used the DNOs' asset populations by year of installation as at March 2003 and applied a replacement profile for each asset category to derive forecast replacement volumes. They derived replacement profiles by benchmarking profiles provided by each of the DNOs in their FBPQs against each other. The resulting benchmark profiles were then applied for all DNOs. They combined the replacement profiles with unit cost data, based on industry experience of actual costs, to determine an annualised spending profile for each DNO.

1.23. PB Power used a modified version of the NLRE modelling for overhead lines. This was based on an assumed refurbishment cycle and proportion of replacement during refurbishment.

1.24. Following the initial modelling PB Power held a number of bilateral discussions with the DNOs. They then applied their judgement to make adjustments and develop final recommendations to Ofgem on appropriate levels of expenditure.

1.25. We developed and applied an Information Quality Incentive (IQI) to bridge the gap between the company forecasts and PB Power's recommendations. This led to a number of companies' restating their forecasts to benefit from the higher incentive rates available to those DNOs whose forecasts were closer to our benchmark, thereby increasing their potential rewards for outperformance.

Annual cost reporting

1.26. The first full Regulatory Reporting submissions for Electricity Distribution related to the 2004-05 reporting year, the final year of the DPCR3 timeframe. A similar approach has now been developed for Transmission (first submission 2006-07) and Gas Distribution (first submission 2007-08).

1.27. Considerable work has been undertaken to build the RRP to report costs in a meaningful way to allow bottom-up benchmarking. We have made a significant number of amendments to the pack each year as we have identified errors or better ways of reporting cost and other data.

Progress

1.28. Significant progress has been made to date in terms of identifying and resolving inconsistencies in the Regulatory Reporting data. Progress has been achieved through detailed examination and questioning of the data entered in the RRP tables and accompanying commentary over the three years in which they have been reported. We have also undertaken specific reviews to address perceived inconsistencies in the reporting of:

- cost allocations by service providers servicing multiple DNOs and/or distribution and transmission licence holders,
- direct labour cost attributions,
- fault cost reporting, and
- engineering labour cost reporting.

1.29. The quality of the data submitted has been limited to some extent by the accuracy of the reporting systems operated by the DNOs. In some cases this is because our requirements for cost reporting cannot be met by the DNOs' own accounting and management information systems. We have noted quite significant differences in the precision of reporting systems maintained by the DNOs. We note that under the cost reporting licence condition (SLC 52) DNOs are required to:

"Keep or cause to be kept……such accounting records and other records as are necessary to ensure that the price control review information of, or reasonably attributable to, the distribution business is separately identifiable in the accounting records of the licensee (and of any affiliate or related undertaking of the licensee);" Standard licence condition 52 3(a)

1.30. DNOs have raised concerns that in some areas costs have not been reported in accordance with the RRP rules by other DNOs. These include:

- attribution of costs between direct and indirect costs by related parties, and
- fault costs relating to particular assets.

1.31. Ofgem takes compliance with SLC 52 very seriously. The time for "bedding in" of RRP has passed and we will now look to recommend enforcement action to the Authority where we believe costs have not been reported in accordance with RRP rules or companies do not have appropriate systems in place.

1.32. As the Rules and DNOs' systems for reporting costs in the RRP have developed, it has become apparent that the costs reported for the 2004-05 financial year are not as robust as later years. **As such we consider that the costs for 2005-06 and later years should be the main focus for the comparative analysis in DPCR5**.

1.33. Asset and resilience data reporting have changed during the annual Regulatory Reporting and are dependent to a great extent on the quality of the reporting systems maintained by the DNOs. For the 2007-08 reporting year we have introduced significant amendments to the RRP to improve the quality of the asset data collected.

1.34. Despite the residual concerns over the consistency of the data available from the annual Regulatory Reporting, it has provided the opportunity for greatly improved cost analysis relative to DPCR4. These improvements mean that we are now able to explore:

- further disaggregating costs and performing more detailed bottom-up analysis,
- determining more relevant cost drivers,
- using time series data in comparative analysis, and
- use of alternative benchmarking techniques, such as DEA.

Objectives and principles of costs and outputs work for DPCR5

1.35. The main objectives of the cost and outputs work are:

- to establish the efficient expenditure requirements for each of the DNOs to deliver an appropriate level of outputs, and
- to identify appropriate incentives for companies to operate efficiently and deliver those outputs.

1.36. The outputs the DNOs will be required to deliver include:

- an appropriate level of reliability of their networks,

- an appropriate quality of service experienced by consumers,
- adequate provision of network capacity, and
- meeting technical and safety requirements.

1.37. At the last price control review we developed the IQI to place more weight on DNOs' forecasts. We aim to continue to place more emphasis on the DNOs' plans in DPCR5. In order to achieve this, we intend to allow the companies greater flexibility in developing their forecasts and we will expect them to engage a wider range of stakeholders to discuss what is required from their networks, justify their plans and explain what they are intended to deliver.

1.38. We intend to use the improved data to further develop our approaches to assessing investment requirements and carrying out benchmarking. For example, we aim to develop more integrated analysis that considers the interactions between different network activities, how different activities can be most effectively grouped together to understand the underlying cost drivers, and to examine the relationships between costs and quality and other network outputs.

Approach to assessing costs for DPCR5

1.39. The key sources of data for assessing networks costs are the RRP and the Forecast Business Plans. The content of the FBPQs will be developed with the DNOs over the coming months.

Approach to assessment of investment requirements

Forecast data

1.40. A key part of the price control process will be to gather information from the DNOs on their forecast business plans. This will include their cost forecasts for the next ten years and supporting information such as their network strategy, key forecast assumptions, justification for the options chosen and the outputs that their plans are intended to deliver.

1.41. We are looking to balance giving greater flexibility to the DNOs, in terms of making the most appropriate business decisions and developing their forecasts, with retaining sufficient consistency to be able to compare what is being delivered. We will use tools such as modelling and benchmarking to assess those forecasts.

1.42. The DNO will need to provide initial high level plans in August this year, after having undertaken their initial stakeholder engagement work. A more detailed business plan, including business cost and financial information, will be required in January 2009. We expect DNOs to again engage with stakeholders to develop these more detailed plans.

Building Block Approach

1.43. As explained in the networks chapter we intend to define a "building block" approach that we expect the DNOs to use when presenting their plans. These building blocks are discussed in more detail in appendix eight and include:

- Load related investment,
- Non load related investment,
- network operating costs,
- engineering overheads, and
- business costs.

Assessment of Forecast Data

1.44. We intend to use a number of tools and techniques in assessing forecasts and setting allowances including:

- a review of the DNOs' methods for deriving their forecasts and the associated assumptions,
- load related expenditure (LRE) modelling,
- non load-related expenditure (NLRE) modelling,
- benchmarking,
- bottom-up analysis, and
- the application of IQI incentives.

1.45. We will look at the robustness of DNOs' methodologies for developing their forecasts and the appropriateness of any assumptions made, with reference to historical data provided by the DNOs and any change in the background drivers.

1.46. For load related investment, these changes in background drivers may include national or regional changes in energy usage, proliferation of demand side management (DSM) and active network technologies, changes in the generation background (including uptake of DE), government policy, population growth and wider economic trends. For non load related investment they may include changes in asset age profiles, asset condition or new requirements to protect against high impact low probability (HILP) events or address network resilience.

Load related investment

1.47. We will use a LRE model to forecast growth in customer numbers and units distributed and to estimate the level of network expenditure required to accommodate these load changes on the network. We will also consider the impact of these costs on engineering overheads and business costs.

1.48. We will consider a number of approaches for benchmarking this expenditure. One option is to compare forecast and historical LRE per customer or unit distributed for a given DNO taking account of changes in the modern equivalent asset values (MEAV) over time. An alternative method is to compare LRE expenditure requirement per customer or unit distributed across DNOs taking account of differences in their MEAVs. In other words, use a time series or cross-sectional basis for carrying out comparisons. Both of these approaches address potential differences in the characteristics for each of the networks.

1.49. We will consider the use of bottom-up assessments (i.e. based on specific schemes) for assessing the DNOs' LRE forecasts. As part of the annual Regulatory Reporting packs, the DNOs provide detailed information on substation loading and fault levels. This information will be assessed with respect to LRE requirements and compared across companies.

1.50. Bottom-up assessment is particularly useful at higher voltage levels (EHV and 132kV). This is because there are fewer of these schemes, they are usually larger and planned further in advance and investment in networks at higher voltage levels is usually "lumpier" (and therefore less easily predicted based on past expenditure levels).

1.51. Based on our assessment of the DNOs' forecasts using these approaches a set allowance can then be determined. Alternatively, we will consider whether it is appropriate to use a revenue driver to flex revenues according to actual loads, customers or other, or to introduce a trigger to allow additional revenues at predetermined levels of the driver.

Non-load related investment

1.52. We will carry out NLRE modelling as one of the tools for assessing DNOs' forecasts for asset related investment. The basic principle for this approach is that each network asset has a finite life and must be replaced at some point during this life to maintain the reliability of the network. Some assets will require replacement before reaching the average asset life and some will not require replacement until beyond the average asset life. The basic information required to populate the model includes the different network asset categories, replacement unit costs, volumes and age profiles.

1.53. The age profile of each of the DNOs' assets provides a snapshot of the number of units remaining in service in a given year and shows the year in which these units were installed. The probability density function represents the probability of each asset needing replacement in every year following. Together, the age profile and probability density function can be used to provide an estimate of the annual volume of asset replacement required.

1.54. Where the forecast volume of work put forward by the DNOs is significantly different from the results of our analysis described above, we will require them to provide appropriate justification for the differences. For example, this may include additional condition based information or supporting analysis that explains the need for accelerated or deferred replacement and any interactions with network operating costs.

Alternative approach to assessment of investment

1.55. There are possible alternative approaches to the assessment and incentivisation of investment such as a requirement for DNOs to contract out together with a rate of return treatment of the out turn costs. We do not consider that such an approach would be appropriate as DNOs are best placed to make a decision as to whether it is most economic to carry out work in house or outsource the work and it is in their interest to do so as long as the cost incentives are appropriate.

Approach to assessment of other network and business costs

1.56. We will continue with the annual review of the RRP as it has developed over the past three years. We will continue to question the data provided with the objective of ensuring that costs have been reported in accordance with the RRP Rules and on a consistent basis.

1.57. Data improvements provide an opportunity to progress our approach to benchmarking. There are a number of developments we will be exploring including:

- disaggregating costs and performing more detailed (bottom-up) analysis,
- determining more relevant cost drivers to costs,
- using time series data in the comparative analysis, and
- using alternative benchmarking techniques, such as DEA.

Review of actual and forecast costs

1.58. The primary review of reported actual costs will take place as part of the annual cost reporting cycle. The initial company submissions for 2007-08 are due in July and we expect to complete the review and publish our report in December 2008. The DNOs will need to submit high level forecast business plans, informed where possible by stakeholder engagement, by 15 August 2008.

1.59. We will undertake a desktop review of each of the submissions and seek to clarify any areas of concern. This will include visits to each of the DNO Groups in September or October. During those visits we will also discuss the assumptions the DNOs have made in their high level forecast business plans with the objectives of assessing the robustness of those assumptions.

Cost Normalisation

1.60. As at DPCR4 we will be carrying out a normalisation process that puts the reported DNO costs on a consistent and comparable basis prior to benchmarking.

1.61. For our ongoing comparative analysis work, we have taken initial views of the normalisation adjustments that ought to be made to the data. These are still in development and as yet no decision has been made as to any final normalisation adjustments. The following lists those adjustments that we have made to date:

- excluding atypical costs,
- excluding non-operational depreciation,
- adjusting for inaccurate accruals,
- excluding atypical accruals and provisions,
- reversing RAV adjustments made during the annual Regulatory Reporting review,
- removing cost recoveries,
- excluding Related Party Margins (via ‘75% rule’),
- reallocation of costs to non ‘distribution activity’ activities,
- reallocation of tree cutting and R&M costs relating to load and non-load projects,
- excluding unmetered electricity costs,
- excluding submarine cable costs,
- excluding island generation,
- excluding overstay fines,
- excluding lane rentals,
- excluding wayleave payments,
- normalising pension payments (for prepayments of ‘normal’ contributions),
- reallocating pensions administration costs,
- adjusting for differences non-operational asset procurement,
- adjusting for the degree of in/outsourcing, and
- adjusting labour and contractor costs for prevailing market conditions.

1.62. Some of these adjustments/exclusions have been made because they are specific to certain DNOs. Others have been made because we believe the cost allowances should be determined outside of a normal benchmarking process. Further work is required for each before we reach a decision about how to treat them.

Benchmarking across DNOs

1.63. We have engaged an economic consultancy to advise us on the application of benchmarking techniques during DPCR5. The work is incomplete but we expect the recommendations to cover the use of top-down and bottom-up regressions together with the use of DEA. The consultant will also advise us on the use of international comparators. Costs for similar companies in US and other European countries are available and we will review their comparability with the DNOs' cost bases.

1.64. There are a number of issues which need to be considered in developing our approach to benchmarking.

1.65. At DPCR4 we carried out benchmarking on a top-down basis. During the recent Gas Distribution Price Control Review we used a mixture of top-down and bottom-up benchmarking. For the comparability work in Electricity Distribution to date we have disaggregated costs to the level of individual activities as reported in the RRP as we work to determine the appropriate drivers for each. As those costs drivers are agreed we will combine some activities for the bottom-up analysis and structure an appropriate CSV for the top-down benchmarking.

1.66. We have been working with the DNOs on both a bilateral and multilateral basis to identify the significant and relevant cost drivers for both the bottom-up and top-down regression work. This will be a key ongoing part of our work over the coming months.

1.67. We are considering the use of external comparators for benchmarking some of the business costs such as: IT & Telecoms; Property Management; HR, Safety and Training; Property Management; and Finance and Regulation.

1.68. We expect to draw on a range of benchmarking results to reach a judgement about future efficiency savings that might be achievable by the DNOs.

Derivation of costs allowances

1.69. Once we have come to a view of the comparative efficiency of the DNOs we will use it to determine appropriate allowances for the price control period. There are several factors that we will need to consider in rolling forwards our benchmarks including:

- the impact of changes in the level of investment on network support and business costs,
- changes in real input prices and the scope for ongoing efficiency savings. We will use a number of different sources to identify the likely changes in input prices and the likely efficiency improvements available to the DNOs over the DPCR5 period, and
- whether it is appropriate for there to be any glidepaths to our efficiency targets. At DPCR4 we allowed no glidepath for DNOs to achieve the benchmark cost levels except for unmerged DNOs.

Cost incentives

1.70. The main overall mechanism for incentivising cost efficiency in DNOs is the RPI-X framework. If a company can deliver the required outputs at a lower level, it is able to keep the difference until the end of the price control period. There are a number of potential weaknesses with such an approach, including:

- it can cause periodicity of incentives. If the benefits of efficiency savings can only be kept until the end of the price control period, DNOs have a stronger incentive to make savings at the beginning of the period. This tends to be observed in practice,
- companies have better information about their costs and there is a risk that they may inflate their forecasts, and
- in the absence of appropriate defined outputs, there may be a strong incentive to reduce costs rather than achieve efficient delivery.

1.71. We have addressed these issues in a number of ways. As part of the work on developing network monopoly price controls, we introduced rolling incentives for investment expenditure. These resulted in incentives of a constant strength throughout the price control period.

1.72. We also introduced the IQI, which allowed us to place more weight on DNOs' forecasts while encouraging them to forecast expenditure at a more realistic level. This incentive mechanism allows the companies to choose from a menu of allowed expenditure (relative to our assessment) and associated rewards or penalties for a range of actual expenditures. It effectively allows the choice between a lower cost allowance, but with a higher savings incentive rate, or a higher allowance with a lower savings incentive rate. As a result of this mechanism some DNOs reconsidered their forecasts at DPCR4.

Issues for taking the incentives forward

1.73. There are a number of key issues that need to be considered for improving these incentives:

- introducing new outputs measures to strengthen incentives for efficient delivery,
- equalising incentives across all categories of costs – there are currently different incentives for opex and capex resulting from the different approaches to assessing costs and rolling incentives only being applied to capex. This may result in perverse incentives in terms of how the DNOs run their business. For example they may choose to outsource to capitalise more costs and benefit from the opex incentives,
- extending the IQI to other areas of costs – as part of this review we are looking to place more weight on the companies' forecasts in general. Applying the IQI more widely may help to achieve this while offsetting risks that companies may overforecast their other network and business costs, and
- applying the IQI under a building block approach – this requires a baseline level of costs to be determined against which the DNOs' forecast are compared, which could be based on historical costs or on Ofgem modelling or benchmarking. The determination of such baselines may be more practical for certain areas of costs, such as non load related capex and reinforcement. It may be more difficult for

additional areas of spend such as network resilience or flooding where there is more uncertainty over levels of expenditure. As such, it may be appropriate to base the IQI on a certain number of building blocks, but apply its results to all areas of costs.

Appendix 7 - Customers

1.1. The customer chapter sets out our high level initial thoughts on meeting customers' needs including quality of service, connections and customer engagement. This appendix provides more technical detail on our initial thoughts for improving the arrangements for specific quality of service areas. It is aimed primarily at DNOs and the industry but may also be of interest to consumer groups and other bodies.

Quality of service interruptions incentive scheme ("IIS")

1.2. This section explores and seeks views on our proposed changes to the IIS target setting methodology for DPCR5.

Target setting methodology

1.3. The DPCR4 CI and CML target setting methodology is predominantly based on disaggregation of HV interruptions data. A detailed process of assigning circuit bands based on physical parameters to HV interruptions is used to benchmark DNOs' performance relative to each other. Benchmarks for HV interruptions are then deduced for each DNO by summing benchmarks for different circuit bands. Benchmarks for the LV, EHV and 132 kV interruptions data are calculated using simpler processes which reflect their relative weight in the overall CI and CML targets. The HV, LV, EHV, and 132 kV benchmarks are then aggregated to set an overall CI and CML target. A detailed explanation of the DPCR4 target setting methodology can be viewed in the document titled Appendix – The losses incentive and quality of service[4].

1.4. We propose to use a similar methodology for calculating unplanned CI and CML targets in DPCR5 to that we used in DPCR4. We are proposing some minor changes at each voltage level, and in dealing with non-attributable interruptions, to further increase the accuracy of the projected targets. These changes are outlined in the following paragraphs.

1.5. We have identified underlying performance for 2002-03 onwards by excluding exceptional and one-off events from the data in line with the DPCR4 rules.

LV

1.6. We split LV interruptions into two categories for DPCR4 target setting - LV Mains and LV Services.

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4 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=41&refer=Networks/ElecDist/PriceCntrls/DPCR4

1.7. In DPCR5 we propose that LV interruptions be treated as a single ‘LV Total’ rather than a split between mains and services. Using a single LV total for recording LV interruptions will remove the inconsistencies of classifying faults as mains or services. Exceptional events can also be easily removed from the interruptions data, and the reporting of LV interruptions will be simplified. A perceived drawback is less accuracy in comparing different circuit types. We have calculated benchmarks under both approaches using the latest data and the split between mains and services has been proven to be insignificant. We invite views as to whether this is an appropriate way to proceed and encourage respondents to suggest alternatives.

HV

1.8. HV targets for DPCR4 were based on three years of interruptions data – 2001-02 to 2003-04. From 2002-03 onwards DNOs have completed standard IIS interruptions sheets with corresponding increases in accuracy of HV interruptions data. HV benchmarks for DPCR5 will include data from 2002-03 onwards to take advantage of the more accurate data.

1.9. For benchmarking purposes, we will use data from a number of years to calculate an average. We are open to suggestions as to how many and which years' data should make up the average. This will mitigate the effect of exceptional years of interruptions to provide more robust targets.

1.10. The DNOs have suggested that benchmark calculations may be skewed when some DNOs have a predominant circuit type in some bands. For example where a DNO has predominantly underground or overhead network (compared with other DNOs who have a much greater mix of both circuit types) they can concentrate technology and operations on that type of topology, producing tougher benchmarks for other DNOs. While we are interested to have suggestions about how to deal with these disparities, we are keen to avoid methodological changes which purely work in the favour of DNOs. We will be striving to ensure a balance between positive refinements for DNOs and additional benefits to customers.

EHV/132 kV

1.11. We set DPCR4 benchmarks for EHV and 132kV using the previous ten years of interruptions data. This interruptions data does not apply a consistent treatment for exceptional events and there are therefore inaccuracies in comparing current actual interruptions to benchmarks set in DPCR4.

1.12. We have consistently stripped out exceptional events from the interruptions data from 2002-03 onwards. In DPCR5 we will use data from 2002-03 in setting EHV and 132kV benchmarks.

1.13. We have made a small accuracy change in calculating benchmarks. We have now divided individual year's interruptions data by the respective year's customer numbers to give the CI and CML, and then averaged over the number of years used.

Non-attributable Interruptions

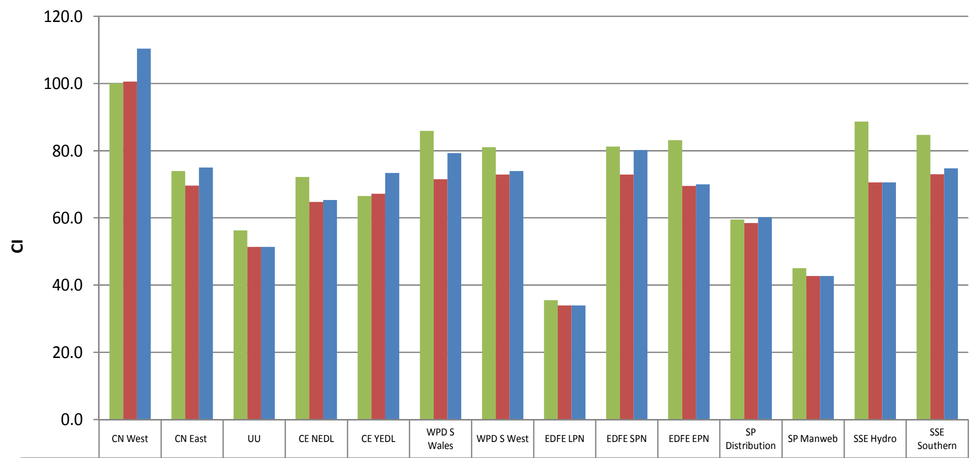
1.14. Non-attributable interruptions are unplanned interruptions that occur on the HV network but cannot be defined into any of the 23 bands for HV disaggregation purposes. Reasons for this include the circuit has changed or has been removed, misallocation of a fault, busbar faults or loss of EHV infeeds caused by an HV fault.

1.15. In DPCR4 non-attributable interruptions were included in the IIS returns but not as part of the HV disaggregation. Non-attributables were instead simply added to the HV target calculation which does not provide the same degree of robustness for setting targets.

1.16. For DPCR5 we will benchmark non-attributables separately. Non-attributables are split into two categories - Loss of Infeed (LoI) and Misallocations. Benchmarking for LoI will be conducted in exactly the same way as that for EHV/132kV. Misallocations are benchmarked in the same way but a scaling factor is applied to discourage interruptions being categorised in this way and to ensure that these interruptions are allocated to HV circuits where possible. The scaling factor is currently set at 80%.

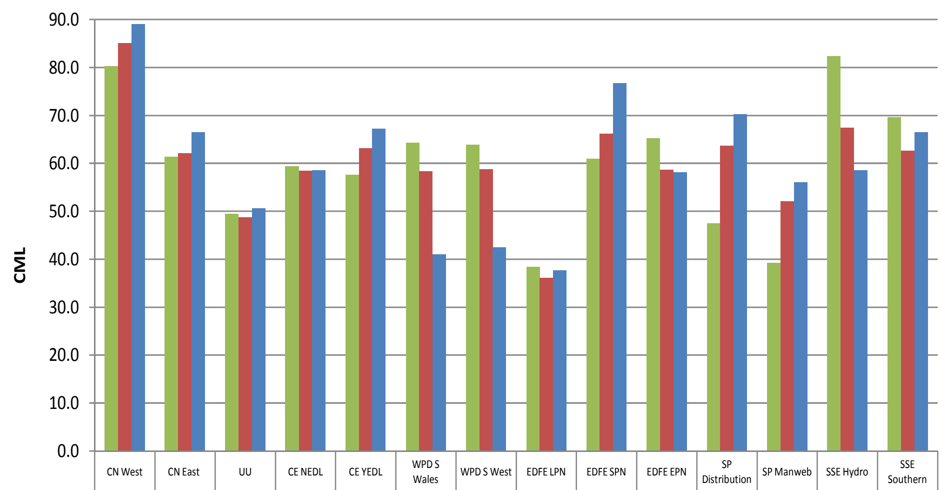
1.17. Figures 1 and 2 show the draft unplanned CI and CML targets for 2015 with the methodology changes outlined in sections 1.6 to 1.16. The average of the actual performance over 2005-06 and 2006-07 is shown for each DNO and the DPCR4 final unplanned targets for 2010 are shown for comparison.

Figure 1 - Draft unplanned 2015 CI targets vs. current actual performance (average 05-06, 06-07)



	CN West	CN East	UU	CE NEDL	CE YEDL	WPD S Wales	WPD S West	EDFE LPN	EDFE SPN	EDFE EPN	SP Distribution	SP Manweb	SSE Hydro	SSE Southern
2010 CI Target	100.1	74.0	56.4	72.3	66.6	85.9	81.1	35.6	81.3	83.2	59.5	45.2	88.7	84.7
2015 CI Target	100.6	69.7	51.4	64.8	67.2	71.6	73.0	34.0	73.0	69.5	58.5	42.8	70.6	73.1
Actual CI	110.4	75.0	51.4	65.4	73.5	79.3	74.0	34.0	80.2	70.1	60.3	42.8	70.6	74.8

Figure 2 - Draft unplanned 2015 CML targets vs. current actual performance (average 05-06, 06-07)



	CN West	CN East	UU	CE NEDL	CE YEDL	WPD S Wales	WPD S West	EDFE LPN	EDFE SPN	EDFE EPN	SP Distribution	SP Manweb	SSE Hydro	SSE Southern
2010 CML Target	80.4	61.4	49.5	59.4	57.6	64.3	63.9	38.4	60.9	65.3	47.5	39.2	82.4	69.6
2015 CML Target	85.1	62.1	48.8	58.5	63.2	58.3	58.8	36.2	66.2	58.7	63.7	52.2	67.5	62.6
Actual CML	89.1	66.5	50.6	58.7	67.3	41.1	42.5	37.8	76.7	58.2	70.3	56.0	58.5	66.5

Pre-arranged interruptions

1.18. In DPCR4 pre-arranged CI and CML targets were integrated with unplanned targets to give an overall CI and CML target for each DNO in each year. The pre-arranged targets were calculated on past and projected pre-arranged work taking into account levels of capex. Analysis thus far of the actual pre-arranged work for the years 2005-06 and 2006-07 against the DPCR4 targets has shown some large variations between the actual and target CI and CML for some DNOs (figures 3 and 4). It is unclear whether the variations are due to increases in efficiency or smaller volumes of capex work. Variations in pre-arranged interruptions relative to the targets may have resulted in DNOs gaining excess (or insufficient) reward relative to their underlying performance.

Figure 3 - Actual pre-arranged CI and DPCR4 allowances

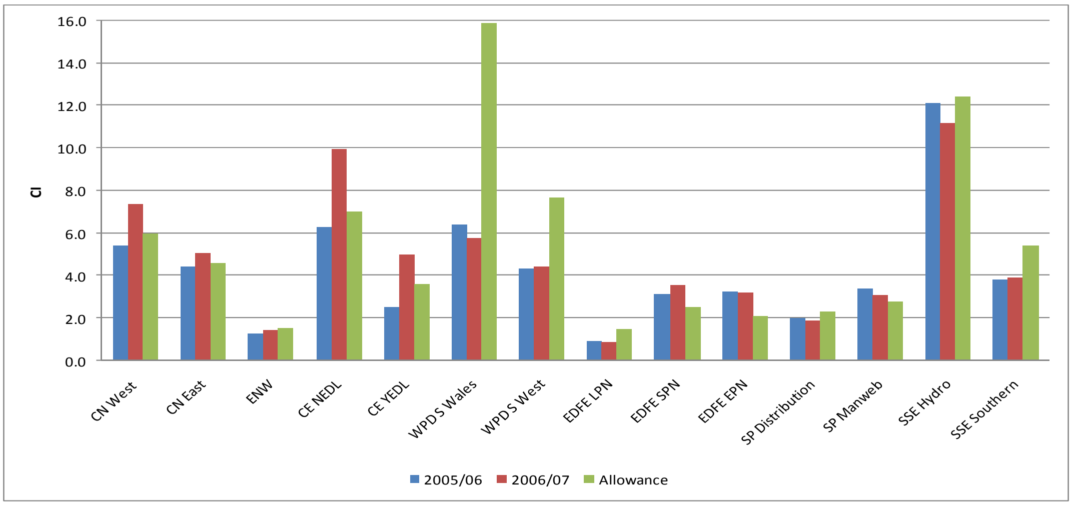
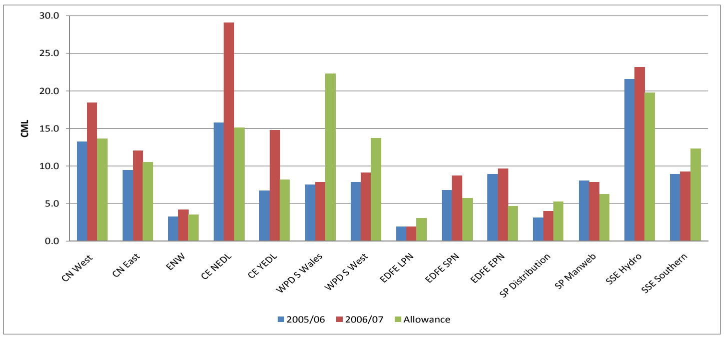


Figure 4 - Actual pre-arranged CML and DPRC4 allowances



1.19. Our discussions with DNOs suggest that it is appropriate to incentivise pre-arranged interruptions by setting targets but that we need to develop a more robust methodology for assessing the level of pre-arranged interruptions.

1.20. We consider that there are two main developments that could be made to improve robustness in this area:

- Creation of work streams that cover the entirety of pre-arranged work to project pre-arranged targets for DPCR5; and
- Tying in the IIS work stream projections with the pre-arranged CAPEX allowance from network investment to give a more accurate picture of what work will be done in DPCR5.

1.21. We propose classifying pre-arranged work into the following four work streams:

- Reinforcement/New Connections
- Tree Cutting
- Maintenance/Inspections
- Rebuilds

1.22. Given past experience of pre-arranged work each DNO should be able to estimate the appropriate pre-arranged CI and CML required for each year in DPCR5.

1.23. We also seek views on whether to continue to combine pre-arranged targets with unplanned targets. Inclusion of pre-arranged targets in DPCR4 resulted in some DNOs having a surplus (and others having a deficit) of pre-arranged CI and CML that filtered through to the unplanned targets. This is likely to occur if a DNO did not undertake all the planned work projected in their target for DPCR4. The extra pre-arranged CI and CML may then act like a bonus of unplanned CI and CML and could potentially, depending on whether the DNO is close to or beyond the limits of the performance band, take the pressure off this incentive with possibly adverse effects for the customer. Keeping the pre-arranged targets separate from the unplanned targets would prevent this occurring. A similar cap and sliding scale mechanism to that currently used could be engaged.

1.24. An alternative to separate targets could involve placing limits on how much a DNO's actual pre-arranged work can deviate from the projected target. This would have the same impact as a cap and collar mechanism if pre-arranged work was to be excluded. A limit is necessary so pre-arranged targets have minimal influence on unplanned targets, at the expense of the customer. The limits would need to be set at levels such that they would not influence efficiency gains made by the DNO.

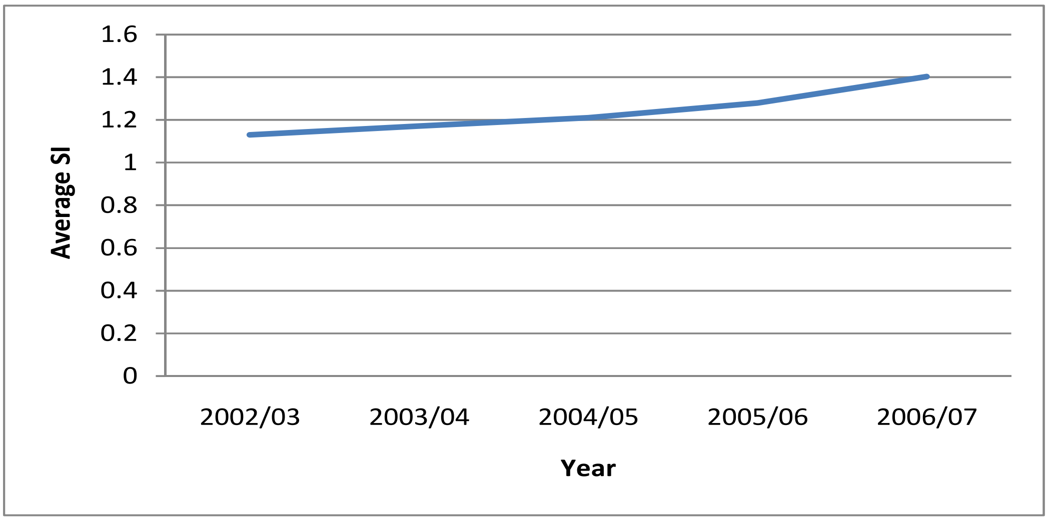
1.25. Actual pre-arranged work undertaken in DPCR5 could be compared with projected pre-arranged work to ensure that the work is being done. Target adjustments could then be implemented to allow for years where more or less pre-arranged work occurs. This would allow efficiency in pre-arranged work practices to be the main driver behind beating targets. This could also be achieved by having a capex driver in the pre-arranged element of the targets.

Short interruptions

1.26. Short interruptions are defined as interruptions that have duration of less than three minutes. The current threshold for interruptions to be recorded under the IIS is those with a duration of three minutes or longer. For this reason there has been a focus on driving down interruptions with a duration of over three minutes and in some cases this has led to an increase in the number of short interruptions. Figure 5 shows an upwards trend for the industry average of short interruptions over the past five years.

1.27. Preliminary findings from our consumer research show that domestic customers prefer frequent, short power cuts over long, infrequent power cuts. Our initial view is that we should maintain the existing methodology for DPCR5.

Figure 5 - Industry average short interruptions per customer



Target Performance

Frontier performance

1.28. The draft unplanned CML targets in figure 2 show some DNOs are currently considerably outperforming their projected targets. If DPCR4 methodology was employed for DPCR5 these frontier DNOs would have no financial incentive to make further CML improvements during DPCR5. Some DNOs could actually experience increases in CML during DPCR5 and still easily outperform their target. These issues need to be managed for DPCR5.

1.29. Frontier DNOs could be given the option of having their targets reflect their current level of performance. As compensation, the frontier DNOs could be given an allowance in exchange for accepting a tighter target. Having a target set at the DNO's current level of performance would lock in the current performance, and further encourage CML reduction as there is now an incentive for the DNO to out-perform their new target. A lower incentive rate could be used to offset the increased risk of exposure to penalties caused by tighter targets. The upfront payment would reflect the risk to the DNO of getting potentially penalised should their actual performance worsen. Options in this area would need to be evaluated in conjunction with the results from the willingness to pay survey.

1.30. An alternative to tighter targets could be an increased focus on worst served customers.

Underperformance

1.31. There is a need to examine the treatment for poorer performing DNOs that have the largest differences between their actual and target CI and/or CML. In DPCR4 an interruption cost allowance was given to each DNO. DNOs that were identified as being poorer performers were given a greater allowance based on costs associated with trying to bring their reliability of supply in line with the better performing DNOs. A potential problem with this approach is that performance in DPCR4 may be below that projected by the level of funding even though the DNOs have received the allowance. It is important that DNOs are not funded twice to make the same performance improvements. We invite views on the merits of having a similar mechanism for DPCR5 or whether in fact there are better alternatives to incentivise poorer performers.

1.32. If an interruption cost allowance is given in DPCR5 it will require some changes to how it is applied. The CI and CML targets which DNOs achieve at the end of the DPCR4 period would need to be compared to those projected by the allowance. If a DNO has failed to meet its targets associated with the DPCR4 allowance then the allowance for DPCR5 could be based on the difference between the targets for DPCR4 and DPCR5. This will prevent DNOs being funded twice for the same improvements. The calculation of the allowance based on costs associated with CI and CML improvements would be done in conjunction with the network investment work stream to better determine the level of the allowance.

1.33. An alternative to using an allowance is to increase the incentive rate of poorer performing DNOs. Such an approach would mitigate customers' exposure to paying more without receiving improvements in performance. Instead they would pay more once the improvements in performance had been delivered. Changing the incentive rate for a DNO would result in changes to either the percentage of revenue exposed or the bandwidth applied to the CI and CML cap and collar and this would need to be considered alongside the results of the willingness to pay work.

Audits

1.34. Quality of service audits have been carried out during DPCR4 by a consortium involving independent consultants and a team from Ofgem. We have had positive feedback on these arrangements. Ofgem involvement means we can get a better understanding of the DNOs' operations and we now have a greater number of people in the team able to undertake audit work. The current audit arrangements are set to continue into DPCR5.

1.35. Given the importance of ensuring the data is correct, our view is that we should continue to audit every DNO, every year. We could enhance the current audit arrangements by introducing an additional larger scale random audit of DNOs during DPCR5. Such an audit could look at a larger sample of incidents than the present streamlined approach and would act to bolster the incentive on DNOs to report data accurately.

1.36. The licence condition specifies minimum accuracy levels of 95 per cent at the overall level and 90 per cent for LV. The current approach is to split the audit sample into two parts and conduct an audit of the accuracy of DNOs' measurement systems and about half of the sampled incidents (Stages 1 and 2) to begin with. The required overall audit accuracy of the initial sample must be at least 97 per cent. If a DNO fails to meet the target the remainder of the sample is audited (Stage 3). The overall accuracy must be at least 95 per cent at this point.

1.37. There is a tendency for DNOs to measure the large and relatively few 132kV and EHV incidents more accurately than incidents on HV circuits. The combined accuracy result for HV and above may therefore give a skewed picture of the accuracy at the different voltage levels. One option is to measure the accuracy of 132kV and EHV incidents separately from HV and with a higher threshold. The accuracy of the different voltages would be measured against their relevant thresholds. Only the voltages that fail to meet their respective threshold would be adjusted. Table 1 lists the audit accuracies of this approach applied to the past five years. Table 2 lists the HV audit accuracies with this approach on a yearly basis.

Table 1 Audit accuracies measured separately for 132 & EHV and HV from 2002-03 to 2006-07

	132 & EHV		HV	
DNO	CI	CML	CI	CML
CN West	100.0%	99.9%	100.0%	99.7%
CN East	99.9%	99.8%	99.7%	99.2%
ENW	100.0%	99.9%	100.9%	101.4%
CE NEDL	100.0%	100.0%	100.2%	99.5%
CE YEDL	100.8%	100.1%	100.1%	100.2%
WPD S Wales	99.7%	100.8%	99.9%	99.9%
WPD S West	99.9%	99.9%	99.7%	99.9%
EDFE LPN	100.1%	100.1%	100.6%	100.2%
EDFE SPN	99.8%	99.7%	100.0%	99.9%
EDFE EPN	99.9%	99.9%	100.5%	99.9%
SP Distribution	100.0%	100.2%	100.1%	100.3%
SP Manweb	100.0%	99.9%	100.1%	100.1%
SSE Hydro	99.8%	99.9%	99.6%	99.5%
SSE Southern	99.7%	100.0%	99.9%	99.7%
Average difference from 100%	0.2%	0.2%	0.3%	0.4%

Table 2 Audit accuracy of HV events by year

	HV 2003/04		HV 2004/05		HV 2005/06		HV 2006/07	
DNO	CI	CML	CI	CML	CI	CML	CI	CML
CN West	100.0%	100.0%	100.2%	100.2%	100.0%	98.3%	100.0%	99.8%
CN East	99.1%	98.1%	100.3%	100.1%	99.4%	100.0%	100.0%	99.8%
ENW	99.2%	100.9%	102.8%	99.9%	100.1%	100.0%	101.3%	100.7%
CE NEDL	99.9%	100.1%	100.2%	100.0%	99.9%	98.2%	101.0%	99.4%
CE YEDL	99.2%	100.0%	99.9%	100.3%	100.0%	100.4%	102.2%	100.5%
WPD S Wales	99.7%	99.5%	100.0%	100.2%	99.7%	99.8%	100.0%	100.0%
WPD S West	99.7%	100.0%	99.5%	99.7%	99.6%	100.2%	100.0%	100.0%
EDFE LPN	102.3%	101.2%	100.1%	100.3%	100.0%	100.0%	100.0%	99.8%
EDFE SPN	99.9%	100.2%	100.0%	99.9%	100.0%	99.5%	100.0%	100.0%
EDFE EPN	100.5%	99.9%	98.8%	99.2%	101.1%	99.7%	103.3%	100.8%
SP Distribution	100.2%	100.3%	100.2%	99.7%	100.0%	102.2%	100.0%	99.8%
SP Manweb	100.1%	100.0%	100.0%	100.3%	100.0%	98.0%	100.1%	100.4%
SSE Hydro	99.0%	99.8%	99.6%	99.3%	99.9%	100.0%	100.0%	97.5%
SSE Southern	100.5%	98.0%	99.2%	100.1%	99.9%	100.4%	100.0%	100.4%
Average difference from 100%	0.6%	0.5%	0.5%	0.3%	0.2%	0.7%	0.6%	0.5%

1.38. We would welcome views on whether the accuracy of 132kV and EHV events should be measured separately and with a higher accuracy threshold.

Exceptional Events

1.39. The current interruption incentive scheme excludes the impact of severe weather events that cause eight or more times the daily mean number of faults at higher voltage over a 24 hour period. The incentive to restore supply during exceptional events is given by compensation payments to customers under the guaranteed standards. Figure 6 shows the incidents exceeding the exceptional event threshold for a DNO over time. Figures 7 and 8 show the exceptional events claimed by all DNOs.

Figure 6 - Incidents exceeding medium (category 1) and large (category 2) event thresholds over the last ten years

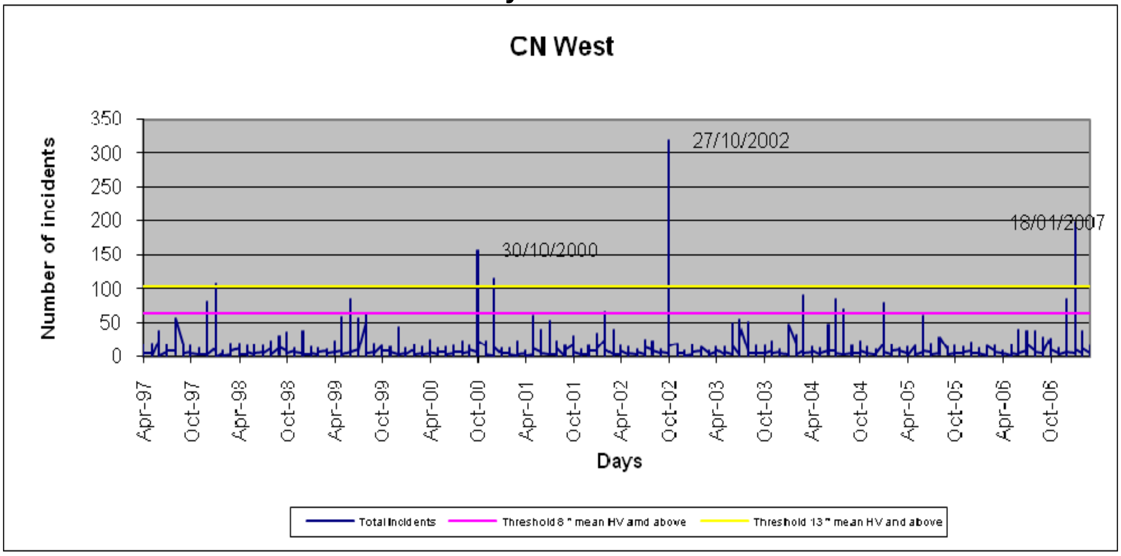


Figure 7 - Allowed exceptional events by incident since 2003-04

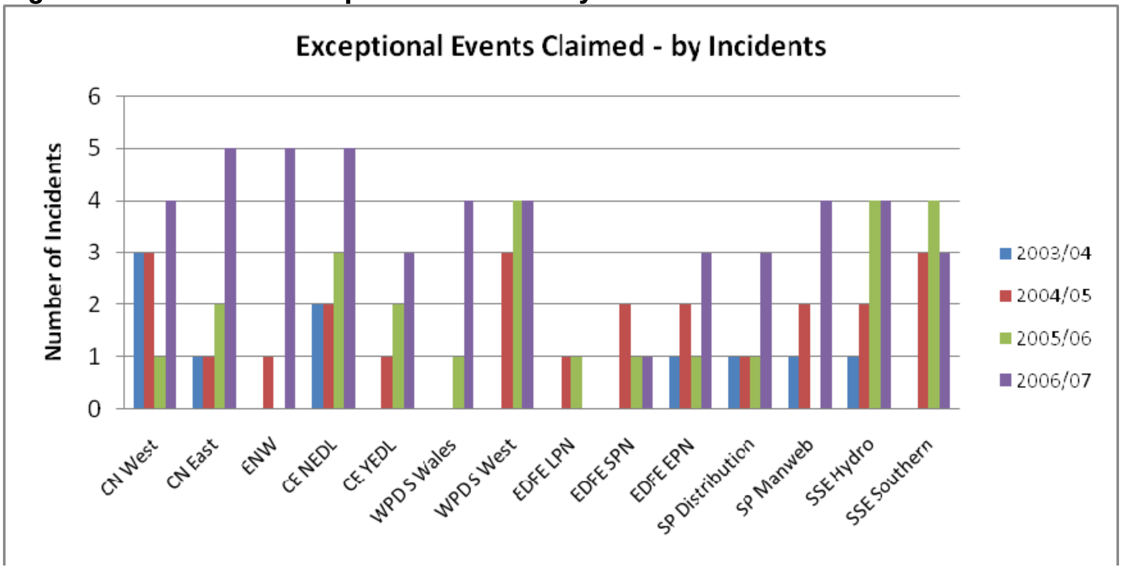
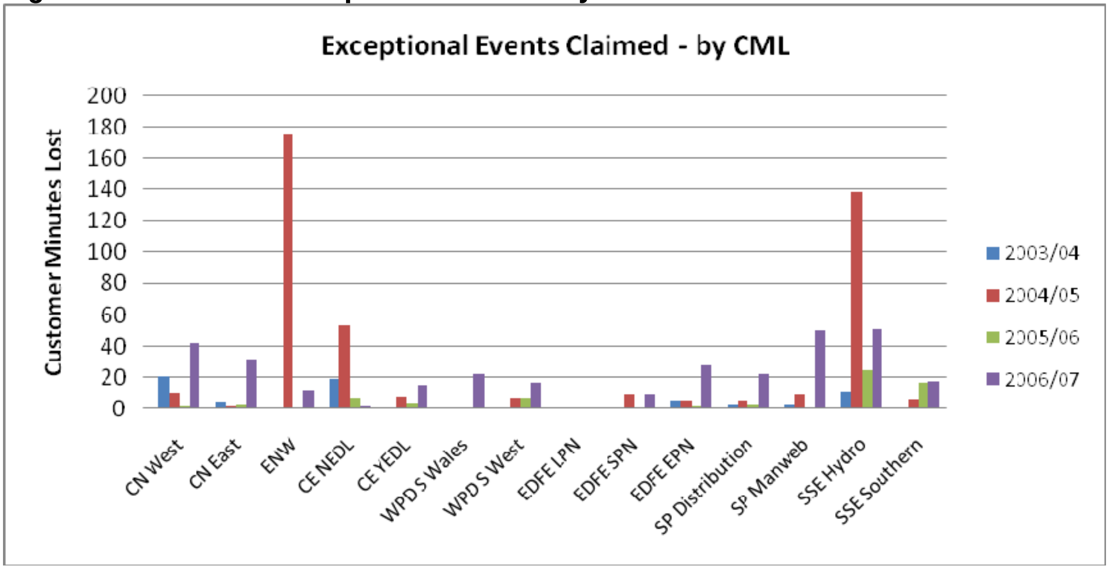


Figure 8 - Allowed exceptional events by CML since 2003-04



1.40. Our view is that if the number of events claimed is large, then all of the claimed events cannot be considered as exceptional. An average of 27 exceptional events per year was claimed from 2003-04 to 2006-07. Arguably, some of these events should be included in the incentive scheme. On the one hand, excluding unusually large events focuses incentives on underlying performance by making fault rates less volatile. The effect of making the exceptional event thresholds higher, or including a percentage of the events in the incentive scheme, would have to be built into CI and CML targets. This could give less incentive to improve day-to-day performance relative to exceptional events, depending on whether the DNO is close to or beyond the limits of the performance band. On the other hand, excluding a large number of events from the incentive scheme reduces the incentive to perform well during these events. Higher thresholds would put more risk on the DNOs.

1.41. If the present approach is used thresholds would remain roughly as under DPCR4. Table 3 compares the revised thresholds using the latest data with those that were set under DPCR 4.

Table 3 - Exceptional event thresholds set at 13* mean HV and above compared to DPCR4 thresholds

	Revised		DPCR 4		Change	
	04/1997 to 03/2007		04/1993 to 03/2003		Change from DPCR 4	
	Category 1 Medium severe weather events 8* mean HV and above	Category 2 Large severe weather events 13* mean HV and above	Category 1 Medium severe weather events 8* mean HV and above	Category 2 Large severe weather events 13* mean HV and above	Category 1 Medium severe weather events 8* mean HV and above	Category 2 Large severe weather events 13* mean HV and above
CN West	64	104	63	103	1	1
CN East	67	108	58	95	9	13
ENW	48	78	47	77	1	1
CE NEDL	37	60	36	59	1	1
CE YEDL	36	59	35	57	1	2
WPD S Wales	46	75	46	75	0	0
WPD S West	57	93	54	88	3	5
EDFE LPN	13	21	10*	17*	3	4
EDFE SPN	46	75	46	74	0	1
EDFE EPN	81	132	72	117	9	15
SP Distribution	78	126	79	129	-1	-3
SP Manweb	65	106	61	99	4	7
SSE Hydro	59	95	61	91	-2	4
SSE Southern	65	105	62	101	3	4

*April 2003-March 2007

1.42. If thresholds were raised to 12 times the daily average fault rate, the number of events that exceed the threshold would be roughly halved.

Table 4 - Annual number of days exceeding various thresholds

Annual number of days exceeding various thresholds					
	12* mean HV and above	11* mean HV and above	10* mean HV and above	9* mean HV and above	8* mean HV and above
CN West	0.5	0.6	1.0	1.2	1.4
CN East	0.9	1.1	1.2	1.4	1.8
ENW	0.6	0.8	0.9	1.0	1.2
CN NEDL	2.0	2.2	2.6	3.2	3.8
CN YEDL	0.2	0.7	0.8	1.1	1.3
WPD S Wales	0.8	1.0	1.3	1.6	1.8
WPD S West	1.5	1.6	1.6	1.8	2.2
EDFE LPN	0.0	0.0	0.0	0.0	0.0
EDFE SPN	0.7	0.9	0.9	0.9	1.1
EDFE EPN	0.6	0.8	0.9	1.2	1.9
SP Distribution	0.6	0.8	0.9	1.1	1.7
SP Manweb	0.7	0.9	0.9	1.2	1.9
SSE Hydro	1.4	1.6	1.7	2.6	3.0
SSE Southern	0.8	0.9	0.9	1.1	1.6
	11.3	13.9	15.6	19.4	24.7

1.43. Exceptional events that were claimed from 2004-05 to 2006-07 were principally caused by gales and lightning. For most DNOs, around a fifth of exceptional events were due to lightning. Lightning type of events have quick restoration times and a relatively small impact on CML. This is illustrated in figure 9 and 10. An option that accounts for this feature could be to introduce a materiality test for exceptional events.

1.44. A small number of exceptional event claims over this period have been one-off exceptional events. At present the rules around one-off exceptional events expose DNOs to the risk of having to make compensation payments under the normal weather standard, which is uncapped, and losing revenue under the incentive scheme, which is capped at three per cent[5], for claims which fail due to the cause not being deemed as outside of the DNO's control. Whilst there have been no catastrophic events of this nature to date, we are aware of DNOs' concerns regarding this area and invite views on whether changes should be made to the one-off exceptional events mechanism and/or the uncapped nature of the normal weather standard for DPCR5.

[5] A DNO could in fact be exposed to a six per cent reduction in revenue if it went from a maximum reward of three per cent due to out-performance to a maximum penalty of three per cent due to under-performance.

Figure 9 - Allowed exceptional events by incident and broken down by cause since 2003-04

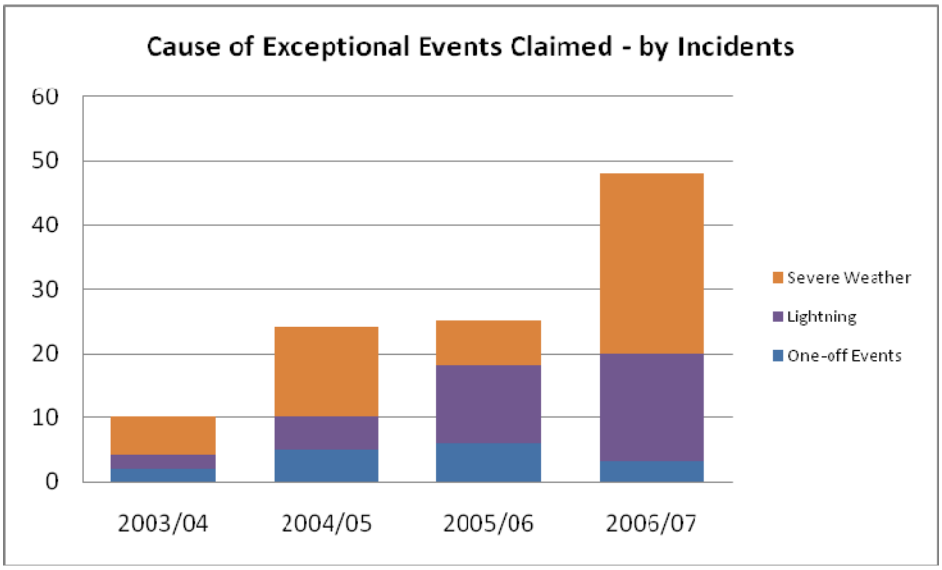
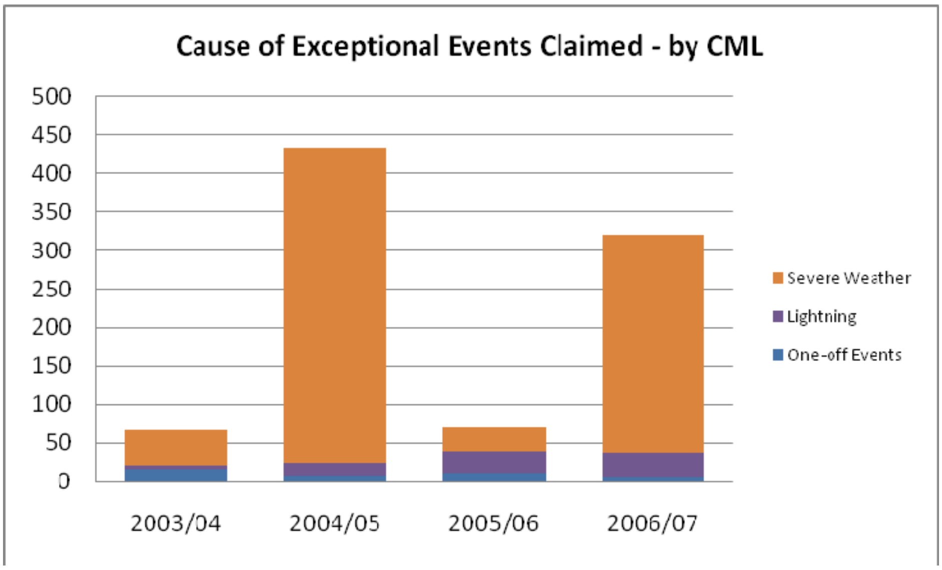


Figure 10 - Allowed exceptional events by CML and broken down by cause since 2003-04



1.45. We are interested to hear respondents' views on the level of the thresholds at which interruptions are currently excluded from the IIS. Should thresholds be raised or should a percentage of exceptional events be included in the scheme? Should a materiality test be introduced, in addition to current thresholds?

Worst served customers

1.46. In our view the IIS has been successful in reducing the overall number of customer interruptions and minutes lost experienced by customers. This is reinforced by results from the qualitative phase of the consumer first research suggesting that few consumers have experienced reliability issues. However, the research to date has not specifically focused on consumers who do in fact experience significant reliability problems. While the IIS is good at improving the average reliability across all customers it falls short of providing incentives for consumers that experience below average reliability.

1.47. Figures 11 and 12 show frequency and duration of interruptions (excluding exceptional events) for 2005-06 and 2006-07. The percentage of consumers who experience one or less interruption per year have decreased from 2005-06 to 2006-07. However the percentage of consumers experiencing two or more interruptions per year has increased over the same time. Similarly the percentage of consumers who have interruption duration of less than one hour has decreased, while those experiencing a duration of greater than one hour has increased in all duration categories. The bulk of customers who already experience a satisfactory supply are getting further increases in reliability while those that have a less satisfactory supply are seeing decreases in reliability.

1.48. The quantitative stage of the Consumer First research is underway and will provide further details on consumer satisfaction. The results of this will be compared to the qualitative results to see if there is an overall trend of satisfaction with reliability of supply for the bulk of consumers. If the bulk of consumers are happy with the current level of network performance there may be a need to build a framework for improving the reliability of supply for the worst served customers.

1.49. Worst served customers are typically on mixed or overhead circuits with low numbers of customers. The expense of installing automation to assist in supply restoration and decreasing CML is relatively high in such low density areas. But if the bulk of customers are satisfied with the current reliability of supply then it may make sense to invest less money where reliability is already good and more money where reliability is below average. The following example gives a basic outline of the economics for CML reduction for rural versus urban customers.

DNOx has 2 feeders, one with few connected customers and one with many connected customers. Each feeder has 10 and 100 connected customers respectively. The following equations show the difference in CML that DNOx will save by reducing the duration of interruptions to each feeder by 10 minutes.

Before reduction in duration of interruption (shown with duration of 60 minutes)
Feeder with few customers: 10 cust × 60 mins = 600 CML
Feeder with many customers: 100 cust × 60 mins = 6000 CML

After reduction in duration of interruption (reduction of 10 minutes)

Feeder with few customers: 10 cust × 50 mins = 500 CML
Feeder with many customers: 100 cust × 50 mins = 5000 CML

The CML saved by reducing the duration of interruption by 10 minutes is 100 CML and 1000 CML for the feeder with few and many customers respectively. As the current IIS incentivises reductions in CML there is a smaller incentive for DNOx to reduce the duration of interruption for customers connected to a low density feeder. Assuming that the cost of the reduction was the same the economic driver would be to spend the money on the urban feeder.

1.50. A definition of worst served customers could be those customers who have interruptions, or aggregated minutes of interruptions, greater than a predetermined value over the regulatory year. Willingness to pay determination could be used as a basis for setting interruptions and duration of interruption levels appropriate for worst served customers.

1.51. It may be appropriate to develop mechanisms to compensate such customers for poor reliability or encourage improvements in the reliability of their supplies. This could include measures such as:

- Tightening the Guaranteed Standard of Performance GS2 supply restoration time under normal conditions (option 1);
- Tightening Guaranteed Standard of Performance GS2A multiple interruptions, or introducing a compensation payment if a customer experiences aggregated duration of interruptions greater than a predetermined level for the year (option 2);
- Create an incentive for DNOs that is targeted at improving the overall reliability of supply to worst served customers (option 3).

Option 1

1.52. The GS2 supply restoration time is currently set at 18 hours under normal conditions. If a customer is still off supply after 18 hours a penalty payment applies. Reduction of this time to 12 hours would help to compensate worst served customers for being off supply for an extended period. It may also encourage DNOs to respond to faults faster, having a positive effect on the reliability of supply to worst served customers. A restoration time of 12 hours would bring GS2 in line with GS2A (four interruptions each lasting three or more hours). A decrease from 18 hours to 12 hours would have cost each DNO an average of just under £0.5m[6] more in compensation payments for 2006/ 07.

[6] Assumed to be domestic payments, calculated as the average amount of people per DNO in the 12 – 18 hr duration bracket (from duration of HV interruptions) and then multiplied by £50.

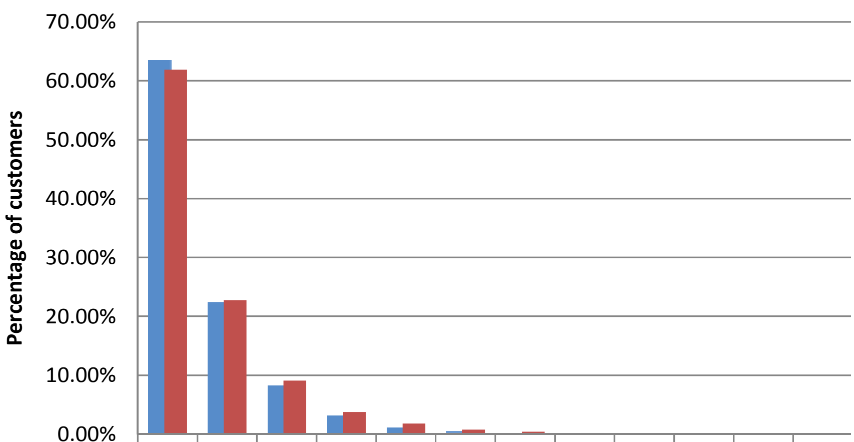
Option 2

1.53. Compensation payments for four or more interruptions each lasting three or more hours over the year are already covered under GS2A, this standard could be tightened. The introduction of a compensation payment for an aggregated duration of interruptions over the year above a certain level would provide protection for worst served customers. Assessing a suitable time for aggregated minutes of interruptions for the year could tie in with consumer surveys of willingness to pay. A possible start point could be 12 hours.

Option 3

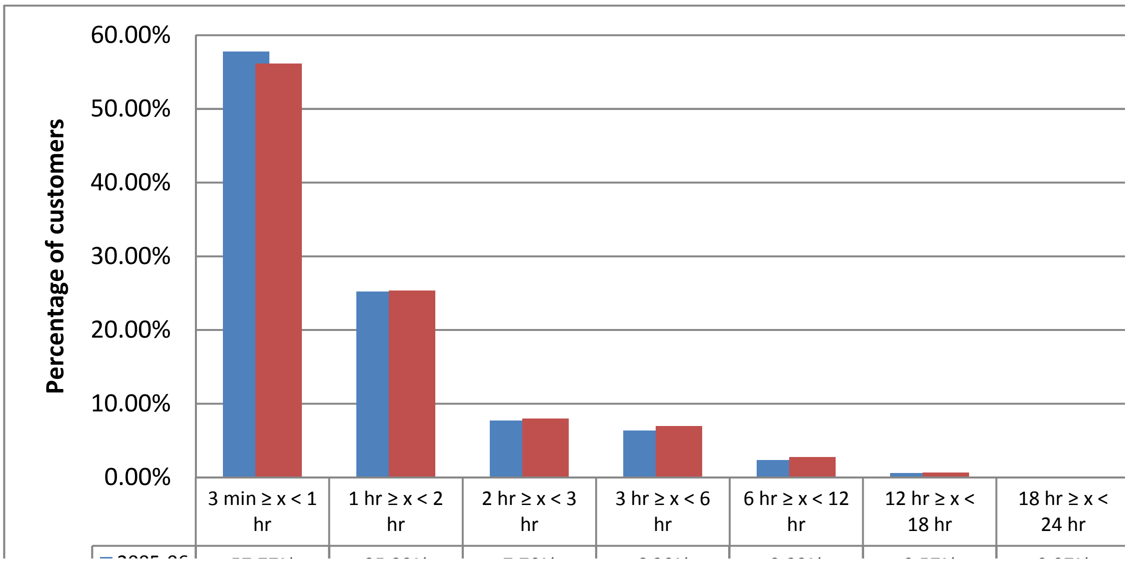
1.54. An incentive scheme could focus on the worst served customers. A threshold based on interruptions and/or aggregated duration of interruptions could be determined to define who the worst served customers are. Targets would then be set for customers defined as worst served as per the threshold. Appropriate incentive levels for both rewarding good performance and penalising poor performance would be set. The aim of such an incentive scheme would be to increase the overall average reliability performance of worst served customers. This would help to stop worst served customers falling further behind the average reliability performance driven by the IIS.

Figure 11 - Frequency of HV interruptions (excluding exceptional events)



	0	1	2	3	4	5	6	7	8	9	10	>10
2005-06	63.66	22.74	8.22%	3.21%	1.26%	0.57%	0.18%	0.07%	0.04%	0.02%	0.01%	0.01%
2006-07	61.89	22.76	9.12%	3.81%	1.81%	0.79%	0.42%	0.20%	0.10%	0.07%	0.02%	0.03%

Figure 12 - Duration of HV interruptions (excluding exceptional events)



Quality of telephone response

Assessed attributes

1.55. There are a number of questions in the current telephony survey that are viewed by respondents as being either the same or very similar. Feedback from the survey has indicated that it is difficult for respondents to distinguish between politeness of staff and willingness of staff to help. Similarly, it has proven difficult for respondents to distinguish between the accuracy of the information provided and the usefulness of the information provided. This view is evidenced by the similarities in the assessed average scores of these attributes over time as set out in table 5. Table 5 shows that the difference in scores between ‘Politeness of staff’ and ‘Willingness of staff to help’ is marginal. On average over the five years, scores for ‘Politeness of staff’ are 0.1 points higher than scores for ‘Willingness of staff to help’. Similarly, scores for ‘Usefulness of information provided’ are 0.02 points higher than scores for ‘Accuracy of information provided’.

Table 5 - Overall mean scores per attribute

Attributes	2002/03	2003/04	2004/05	2005/06	2006/07
Politeness of staff	4.52	4.63	4.63	4.68	4.68
Willingness of staff to help	4.34	4.48	4.51	4.56	4.58
Accuracy of Information provided	4.13	4.23	4.09	4.15	4.06
Usefulness of the Information provided	4.07	4.22	4.08	4.16	4.08
Satisfaction with Speed of Response	N/A	N/A	4.13	4.14	4.10
Overall *	4.07	4.21	4.18	4.31	4.30
Satisfaction with the information provided *	3.27	3.43	3.46	3.92	3.94
Satisfaction with overall quality *	4.12	4.24	4.29	4.31	4.26
Assessed including Speed of Response *	N/A	N/A	4.29	4.34	4.30

Note: Customer satisfaction with speed of telephone response was measured on a trial basis during DPCR3 and included as an assessed attribute from April 2005.

Politeness and willingness remain the highest scoring attributes in the survey and have shown increases since 2003/04. All other attributes have shown a slight decline.

1.56. Because of this duplication we propose to streamline the existing assessed attributes in the survey from five to three and suggest the following:

- willingness of staff to help,
- accuracy of the information provided, and
- satisfaction with speed of response.

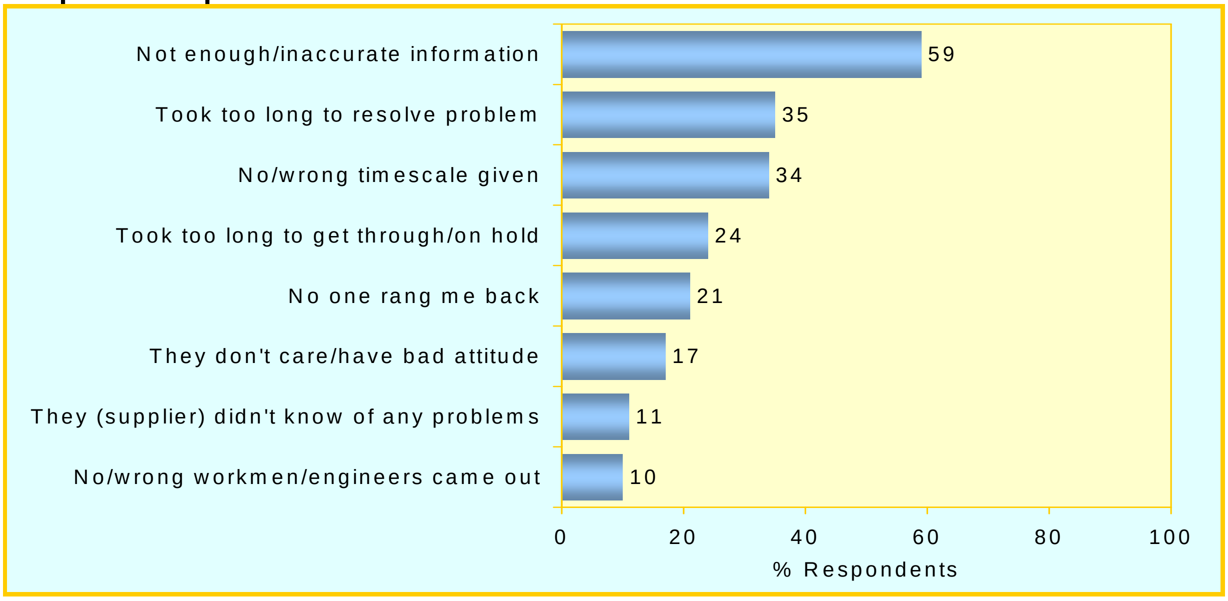
1.57. We favour these particular attributes as we consider that they are easiest for respondents to assess and overall they provide a broad indication of quality. We welcome views on whether these are the most appropriate attributes to retain as part of the survey.

1.58. The telephony survey provides over 12,000 customer contact opportunities per year for Ofgem. By streamlining the existing assessed attributes we consider that there will be scope to obtain more information from the survey and potentially a broader view of how customers perceive their DNO.

1.59. Though the overall score for the quality of the telephone response is high, customers that do indicate dissatisfaction in this area are asked what aspects of the service they are dissatisfied with. Figure 13 shows reasons for dissatisfaction from

2006/07 surveys. The main reason for dissatisfaction is 'Not enough/inaccurate information.' This should be viewed in light of the difficulties faced by the DNOs in providing exact details of aspects such as restoration times at the time of the customer call. Given this, we invite views on how the quality of information could still be improved.

Figure 13 – Reasons for dissatisfaction with the overall quality of the telephone response 2006-07



1.60. It is evident that most of the concerns relate to the DNOs' follow-up response after the call. Based on this feedback we would like to explore the potential to include some further customer satisfaction measures based on the quality of the DNO's follow-up response. Our initial thoughts on questions to include are:

- If your electricity supply was interrupted, how satisfied were you that your electricity supply was restored as soon as possible?
- How satisfied were you with the way DNOx communicated with you while your supply was interrupted? For instance, were you adequately updated of their progress in restoring your electricity supply?

1.61. It may not be appropriate to incorporate these questions into the incentive without first conducting a pilot survey so we propose using the last year of DPCR4 to ensure they are appropriate. We are open to views on questions to ask and whether the questions should be consistent over time or if they could be changed in focus according to areas of interest.

Key measures

1.62. To supplement the telephony survey results, Ofgem collects data from the DNOs against a number of key measures concerned with their telephony systems. This data is currently not incentivised as part of the scheme, but provides some context on DNOs' telephony systems. The key reporting measures are set out in table 6.

1.63. This section considers whether we should bring any of the key measures into the incentive scheme to provide a broader view of quality in addition to the customer satisfaction attributes.

Table 6 – Explanation of key measures for the reporting template

Key Measure Definition	Key Measure Definition
KM1	Total calls on the specified lines
KM2	Total calls answered by an automated message providing fault details (excluding
KM3	Total calls answered by an agent
KM4	Mean time taken for response by an agent
KM5	Total number of unsuccessful calls, comprising: (a) Total calls not reaching the specified lines (b) Total calls terminated by the DNO during the IVR/group announcement (c) Total calls not allowed into the queue or flushed from the queue (d) Total calls abandoned by the customer in the queue

KM1, KM2 and KM3

1.64. We consider that KM1, KM2 and KM3 provide a useful measure of the volumes of calls answered and how they are handled by the DNOs. We do not consider that they directly lend themselves to being incentivised as part of the scheme.

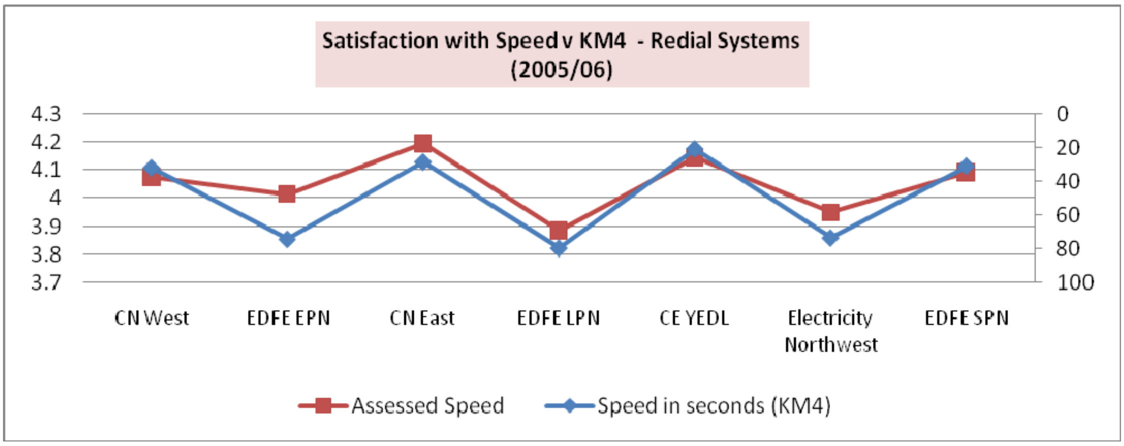
1.65. One potential shortcoming of the current telephony scheme is that it only surveys customers that have spoken to an agent, yet a substantial proportion of calls get through to an automated messaging service. A concern with the current approach could be that DNOs can obtain the same score under the scheme by answering a different percentage of total calls with agents, messaging or failing to answer (i.e unsuccessful calls). Customers who are not satisfied with the quality of response provided by messaging can and do call back to speak to an agent. These customers are then in scope for our current telephony survey mechanism. DNOs are thereby incentivised to ensure that the quality of their messaging reaches an acceptable level of service otherwise they would have to manage a far higher volume of calls to their call centres.

KM4 - Speed of response

1.66. We currently measure speed of response as an assessed attribute within the telephony survey and require DNOs to provide their own measures of speed of response as part of their RIGs reporting (KM4). Currently, only satisfaction with the speed of response is incentivised as part of the scheme.

1.67. Figure 14 shows that there is a strong correlation between satisfaction with speed of response and KM4. Given that satisfaction with the speed of response is already included within the scheme, we consider that it would be unnecessary to also provide an additional incentive for KM4. We consider that the cost implications of introducing an incentive around this measure may be prohibitive and we have no evidence to suggest that customers would like their calls answered quicker.

Figure 14 - Correlation between satisfaction with speed of response and KM4 on redial systems (2005-06)

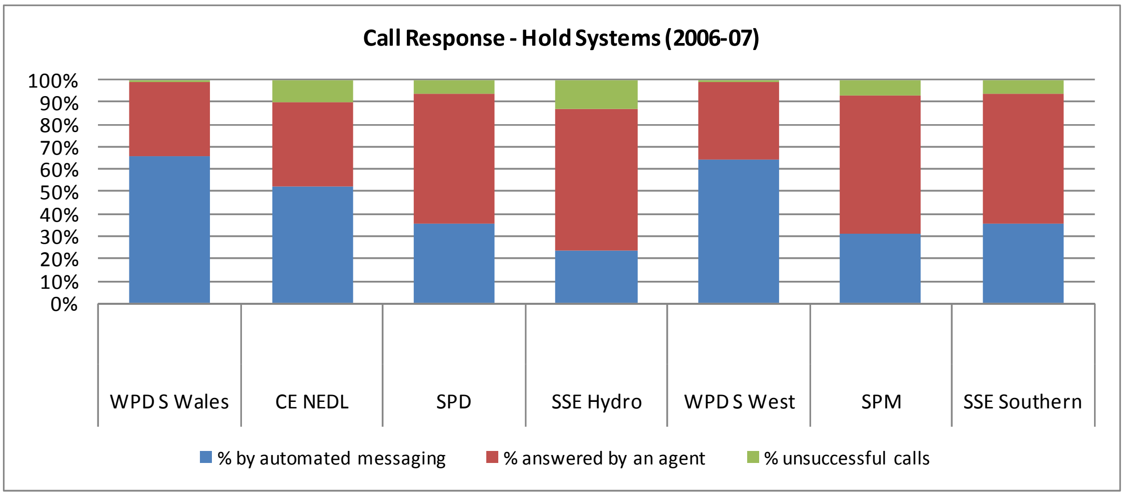


KM5 - Unanswered calls

1.68. DNOs have been providing data in their regulatory instructions and guidance reporting on the number of unsuccessful calls and we are concerned that in certain situations the current survey mechanism does not reflect variances in percentage of unsuccessful calls by DNO. It is possible for two DNOs to achieve the same scores under the survey but to have successfully dealt with different percentages of calls over the year. We invite views as to whether the inclusion of unsuccessful call percentages is desirable and feasible within a telephony incentive scheme for DPCR5.

1.69. Figure 15 shows the proportion of calls answered by an agent, automated messaging and the proportion of calls unanswered.

Figure 15 - Call Response - Hold Systems (2006-07)



Guaranteed standards of performance

1.70. Table 7 sets out the existing guaranteed standards of performance and associated penalty payments.

Table 7 - Guaranteed Standards of Performance

Guaranteed Standards of Performance			
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	£20 for domestic and non-domestic customers
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £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	£50 for domestic and non-domestic customers
GS3	Estimate of charges for	5 working days for simple work and 15 working days	£40 for domestic and non- domestic

Guaranteed Standards of Performance			
Reporting code	**Service**	**Performance Level**	**Penalty Payment**
	connection (Regulation 11)	for significant work, otherwise a payment must be made	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	£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	£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	£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	£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	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £25 for each further 12 hours

* Customers need to claim under these standards, for the remaining standards payments are automatic.

1.71. Table 8 sets out the number and value of payments made under each guaranteed standard since 2005. Respondents should note that the figures highlighted in orange include ex-gratia payments made by DNOs to customers, which may include scenarios where the standard was failed but a valid claim from the customer was not received.

Table 8 – Number and value of payments made by all DNOs under the guaranteed standards (including ex-gratia payments)

	2005/06		2006/07	
	Number of payments made	Value of payments	Number of payments made	Value of payments
EGS1	59	£1,180	87	£1,740
EGS2	4751	£237,550	180149	£2,028,584*
EGS2A	1072	£53,600	1003	£50,150
EGS3	14	£560	86	£3,440
EGS4	200	£4,000	783	£15,660
EGS5	2	£40	3	£60
EGS8	4	£80	20	£400
EGS9	9	£180	117	£2,340
EGS11A	682	£17,050	3	£75
EGS11B	0	£0	3,301	£82,525
EGS11C	0		0	£3,617,050*
EGS12	0	£0	0	0

Note: DNOs have an incentive to pay customers under the normal and severe weather standards as the difference between what customers are entitled to and what the DNOs have paid will be recovered from DNOs via adjustments to price control revenue. The figures for GS2 and GS11C for 2006-07 represent our calculation of the compensation payments due to customers across all DNOs. These calculations are based on domestic customer compensation levels.

Audit requirements

1.72. From responses to the May 2007 scoping paper, we note concerns raised by energywatch regarding the accuracy of DNOs' guaranteed standards reporting and a suggestion that this data should be audited by Ofgem. Ofgem currently requires the

DNOs to have in place appropriate quality systems to ensure consistent reporting against the guaranteed standards. DNOs are also required to carry out regular internal audits of the operation of the guaranteed standards to review the effectiveness of their performance standard systems.

1.73. We recognise that there have been inconsistencies in the interpretation of the guaranteed standards reporting requirement amongst DNOs, which we have addressed with individual DNOs as and when they have arisen. To provide greater confidence in the accuracy of guaranteed standards returns, we now cross-check audited interruptions data with the guaranteed standards returns to identify and verify any discrepancies in the reporting. As a result of this checking exercise we have required DNOs to correct their data retrospectively. This checking process gives us greater confidence over time that DNOs are reporting correctly and as such we do not believe a separate audit process for guaranteed standards is warranted at the present time.

Customer service reward scheme

Table 9 - Rewards made under the scheme since 2005-06

	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	
	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.

Table 10 - Examples of best practice commended by the customer service reward panel since 2005-06

Best practice
Corporate social responsibility
▪ 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 senior management involvement and commitment.
▪ A range of initiatives related to the business such as addressing potential skill shortages or mitigating environmental impacts.
▪ Inclusion of contractor performance within the company's CSR programme and active encouragement of staff involvement.
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 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 is properly trained to help vulnerable customers.
▪ Commitment and involvement of senior staff.
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.

Best practice
▪ 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.

Undergrounding in Areas of Outstanding Natural Beauty ("AONBs")

1.74. We are aware, from discussions and correspondence with stakeholders, that there are some perceived limitations of the undergrounding mechanism and ideas about the scope for improvement:

- Costs caps are perceived to be unrealistic for some projects within the scope of the scheme as the topology of the land has a strong bearing on cost. Many DNOs and designated bodies have cited examples of viable projects that they have rejected for cost reasons. We now have two years worth of data from DNOs of the costs of undergrounding scheme. Nonetheless, as part of this consultation process we are interested in receiving details of schemes that have been considered and rejected on the basis of cost;

- The lack of BT participation in the scheme means that visual impact is limited on certain projects where poles are shared between the DNO and BT;

- The mechanism does not prevent new overhead lines being constructed in AONBs and National Parks which may detract from the overall impact of the scheme in some areas. We are mindful that DNOs have an obligation to provide least cost connection solutions, which could be an overhead line route through an AONB or National Park. Given this obligation, we are not minded to adapt the scheme to prevent future overhead lines in designated areas;

- There is no element of compulsion to the scheme so some designated bodies may not benefit. We perceive that the mechanism works well where there is buy-in from DNOs and it is also a discretionary funding mechanism. As such we consider it would be contrary to the spirit of the mechanism to compel DNOs to take part; and

- The mechanism is limited to AONBs and National Parks. We invite views on whether there are other protected or conservation areas that could benefit from the mechanism.

1.75. Views are welcome on the above and any other potential areas for further development.

Voltage quality

1.76. Voltage quality standards aim to ensure a reliable power supply voltage is maintained within specified limits. The CENELEC standard EN 50160[7] applies within the UK apart from where it has been qualified by the ESQCR[8] standard. EN 50160 defines the voltage characteristics of electricity supplied by public distribution systems. The voltage magnitude set in EN 50160 is surpassed by that set in ESQCR. This is the only voltage quality amendment by ESQCR over EN 50160. Other UK voltage quality standards include the ENA engineering recommendations ER P28, ER P29 and ER G5/4.

1.77. In 2006 the European Regulators' Group for Electricity and Gas ("ERGEG") released a public consultation document titled *Towards Voltage Quality Regulation in Europe*[9]. ERGEG are proposing EN 50160 should be revised. The major focus for revision is on improved definitions for voltage quality parameters. This includes a complete reworking of how different voltage quality parameters are defined, measured and revised limits.

1.78. The magnitude of voltage quality issues in UK distribution systems is very small compared with other types of quality of supply issues. The guaranteed standards of performance GS5 cover the investigation of voltage complaints. In 2005-06 there was an average of approximately 450 complaints and in 2006-07 an average of approximately 400 complaints in each licensed area. In the same years the average number of short interruptions in each licensed area was approximately 2m and 2.5m respectively. Table 11 provides a summary of voltage complaints derived from medium term performance returns.

[7] BS EN 50160:2000 Voltage characteristics of electricity supplied by public distribution systems http://www.reo.co.uk/power_quality_standard_en_50160
[8] The Electricity Safety, Quality and Continuity Regulations 2006 (as amended) SI No. 1521
[9] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/ARCHIVE/ELECTRICITY/Voltage%20Quality/CD

Table 11 - Voltage complaints per DNO for 2005-06 and 2006-07

	Number of Voltage Problems		Visits Necessary		Visits Unnecessary	
	2005/06	2006/07	2005/06	2006/07	2005/06	2006/07
CN West	483	456	483	456	0	0
CN East	568	502	568	502	0	0
UU	698	628	603	535	95	91
CE NEDL	128	380	128	380	0	0
CE YEDL	102	480	102	480	0	0
WPD S Wales	39	22	39	19	0	0
WPD S West	94	74	90	74	4	0
EDFE LPN	130	118	88	37	42	0
EDFE SPN	469	402	444	397	25	0
EDFE EPN	715	501	659	488	67	0
SP Distribution	725	634	649	572	76	61
SP Manweb	430	379	419	379	7	0
SSE Hydro	364	294	109	274	255	20
SSE Southern	1311	921	394	746	917	185
Average	447	414	341	381	106	26

1.79. In our view the impact of the proposed revision of EN 50160 appears to be much larger than the problem. The costs of adhering to tighter voltage parameter limits or new measuring intervals could far outweigh the benefits to consumers. We are currently investigating the ramifications of the EN 50160 review and would welcome views from respondents on current voltage arrangements and proposed changes.

Appendix 8 - Proposed building blocks

Introduction

1.1. This appendix provides further details on the current thinking regarding the individual building blocks to be used by DNOs when presenting their forecasts for network costs and business costs for DPCR5. We expect to refine the building blocks over the coming weeks based on feedback and discussions with the DNOs and other stakeholders.

1.2. Finalised guidance including spreadsheet proformas for submission of the high level forecasts, required by 15 August will be published by the 16 May. Following the submission of the high level forecasts we will publish further guidance covering the detailed forecasts required by 23 January 2009.

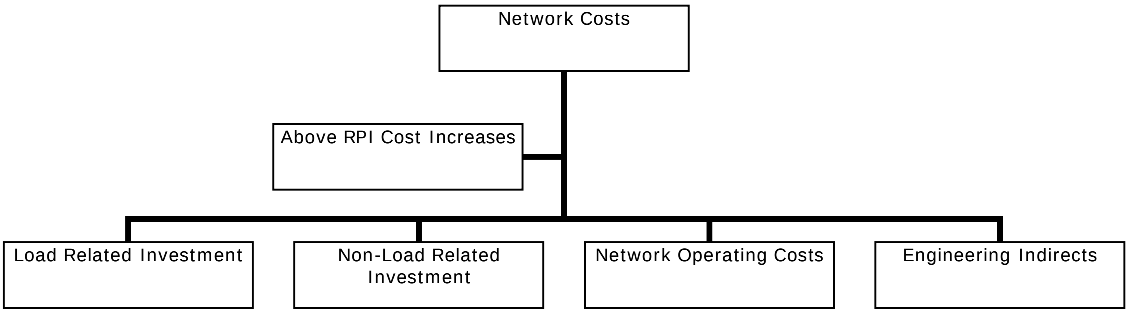
Building blocks - Networks costs

1.3. The proposed building blocks are grouped into four categories:

- load related investment,
- non-load related investment,
- network operating costs, and
- engineering overheads.

1.4. In addition there will a standalone building block to capture cost increases above RPI. This is captured in the diagram below.

Figure 1 - High level building blocks for network costs



Overall assumptions

1.5. Building blocks for load related investment, non-load related investment and network operating costs will be on direct cost basis as defined by the current RRP rules. Engineering overheads will include network costs that are defined as indirect costs in the current RRP rules.

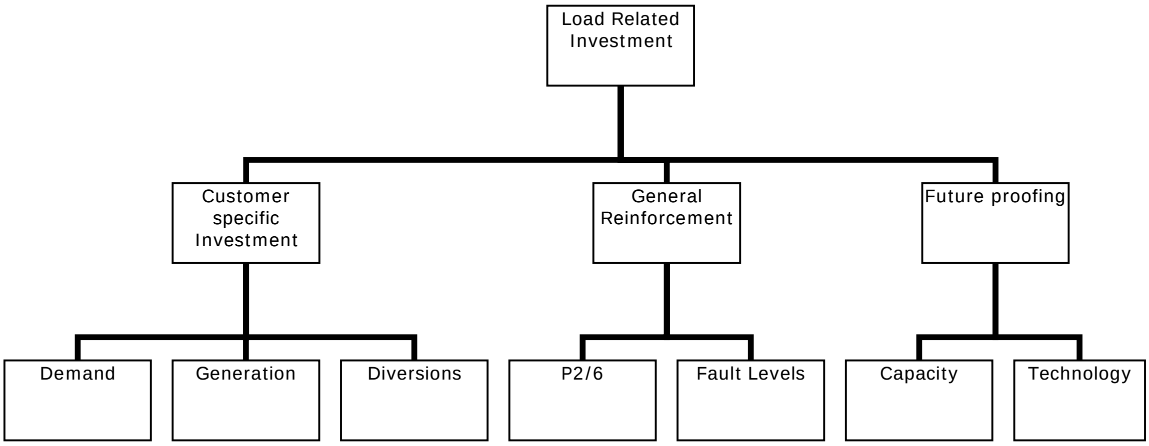
1.6. All costs should be assumed to increase in line with RPI. A stand alone building block will capture the impact of overall cost changes on the total forecast.

Load Related Investment

1.7. This grouping covers all expenditure on new or replacement assets to increase network capacity (including fault level capacity) in response to changes in demand or generation. Load related investment also includes customer requested diversions. The proposed load related investment building blocks are:

- customer specific investment,
- general reinforcement, and
- future proofing.

Figure 2 - Building Blocks - Load Related Investment



Customer specific Investment

1.8. Customer specific investment includes all investment which is required due to changes in customer requirements. This includes new connections as well as changes to existing connections. Customer specific investment will be further split into:

- demand,
- generation, and
- diversions.

1.9. A forecast of customer contributions will also be required.

General Reinforcement

1.10. This includes all investment made against changes in the general demand or generation background that is not directly attributable to a specific demand or generation connection. General Reinforcement will be further split into:

- investment to maintain P2/6 compliance, and
- investment to maintain fault levels within requirements.

Future proofing

1.11. This includes all investment in addition to normal planning requirements to future proof the network. This may, for example, be investment in higher ratings of equipment to accommodate future load or generation (where cost benefit analysis supports this) or investment in active network technologies (smart grids) to support future levels of DG where this reduces the required investment based on full life time costing. Future proofing will be further split into:

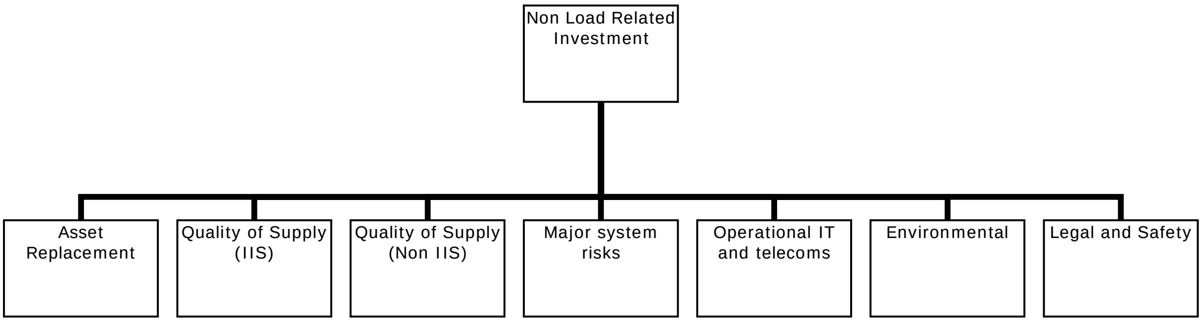
- investment in additional network capacity, and
- investment in enabling technologies.

Non-Load Related Investment

1.12. This grouping covers all expenditure on new or replacement assets where the prime driver is not load related or at the request of a customer (diversions). In most cases the main driver will be asset specific for example asset condition. The proposed non load related investment building blocks are:

- asset replacement,
- quality of supply (IIS),
- quality of supply (Non IIS),
- major system risks,
- operational IT and telecoms,
- environmental, and
- legal and safety.

Figure 3 - Building Blocks - Non Load Related Investment



Asset replacement

1.13. Asset replacement includes investment made to replace assets on the network where the asset has reached a condition that it is no longer fit for purpose and replacement is the most economic solution. The building block will also include replacement of plant items that have failed. Asset replacement will be further split by:

- voltage e.g. 132 kV, EHV, HV, LV, and
- main equipment e.g. transformers, switchgear, OHL, UG cables, services and civils.

1.14. Further consideration may be given to combining LV and HV cable condition replacement with fault repairs as suggested by a number of DNOs.

1.15. In general asset replacement will be based on achieving an acceptable long term risk profile or health index distribution. External drivers such as incentive rates for losses and QoS should be assumed to be zero for this building block. Losses and QoS improvements will be captured in other building blocks.

1.16. In addition to the risk profile or health index distribution the DNO should be able to quantify what asset replacement investment will deliver in terms fault rate, CIs and CMLs and technical losses.

Quality of supply (IIS)

1.17. This includes all quality of supply investment that is targeted at improving average CIs and CMLs as incentivised under the IIS mechanism. This may include incremental increases in condition driven asset replacement.

1.18. The building block will define the incremental cost quality relationship for different types of investment centred around the CI and CML performance that would be delivered by the level of asset replacement proposed in the asset replacement building block.

Quality of supply (Non IIS)

1.19. Quality of supply (Non IIS) includes all other investment aimed at improving performance experienced by customers that is not captured by average CIs and CMLs or where the IIS incentive rate is unlikely to fully fund the investment. For example investment targeted at improving:

- network resilience,
- service levels to the worst served customers, and
- the number of short interruptions.

1.20. It will be important that the DNO is able to measure and quantify the outputs delivered.

Major system risks

1.21. It is envisaged that this will be in response to the risks presented by high impact low probability events (HILP) which may not be captured under normal planning assumptions. Like all investment expenditure, it must be shown to benefit customers at an economic cost. Possible areas of investment include:

- reinforcement above P2/6,
- increased flood protection, and
- protection of supplies to critical services.

1.22. For example reinforcement above P2/6 would include investment in network infrastructure to provide an increased level of electrical capacity or redundancy at a level beyond that required by P2/6 under nominal planning assumptions. It is envisaged that this will be in response to the risks presented by high impact low probability event (HILP) which may not be considered by P2/6 as credible event.

Operational IT and telecoms

1.23. This will cover any major investment in Operational IT and telecoms. For example, it may include investment required as result of changes causes by BT moving to their 21 century platform.

Environmental

1.24. The environmental building block will cover investment that is targeted at improving environmental performance. This will include investment to:

- reduce technical losses,
- reduce oil pollution,
- reduce leakage of SF6,
- improve visual amenity, and
- reduce noise pollution.

1.25. It is expected that for some areas the costs will be incremental to asset replacement for example the incremental cost of reducing technical losses via the installation of low loss equipment or overrated underground cables when asset replacement is undertaken.

Legal and Safety

1.26. Investment to meet specific legal or safety requirements not addressed via normal asset replacement for example,

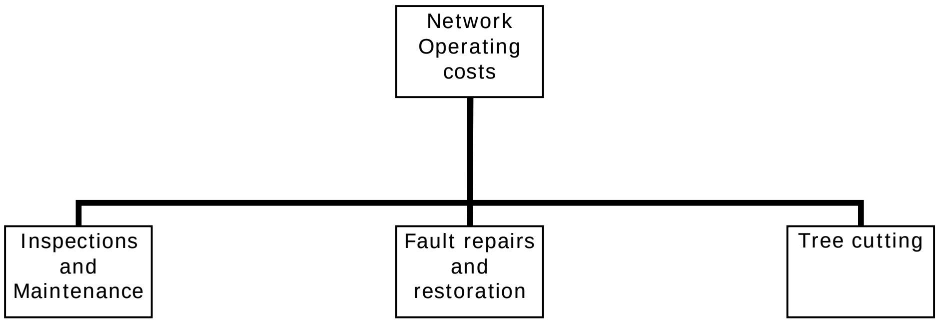
- site security,
- ESQCR safety clearance,
- asbestos removal, and
- investment to remove operational restrictions.

Network operating costs

1.27. This grouping covers all expenditure on the network which does not result in new or replacement assets. The proposed network operating costs are:

- inspections and maintenance,
- tree cutting, and
- fault repairs and restoration.

Figure 4 - Building Blocks - Network Operating Costs



Inspections and maintenance

1.28. Expenditure on Inspections and maintenance as defined in the current RRP rules.

Fault repairs and restoration

1.29. Expenditure on fault repairs and restoration and as defined in the current RRP rules. Further consideration may be given to combining LV and HV fault repairs with cable condition replacement as suggested by a number of DNOs.

Tree cutting

1.30. Expenditure on Tree cutting as required under ESQCR 2006 split between:

- tree clearance in compliance with ENA TS 43-08, and
- tree resilience clearance in compliance with ETR 132.

Engineering Indirects

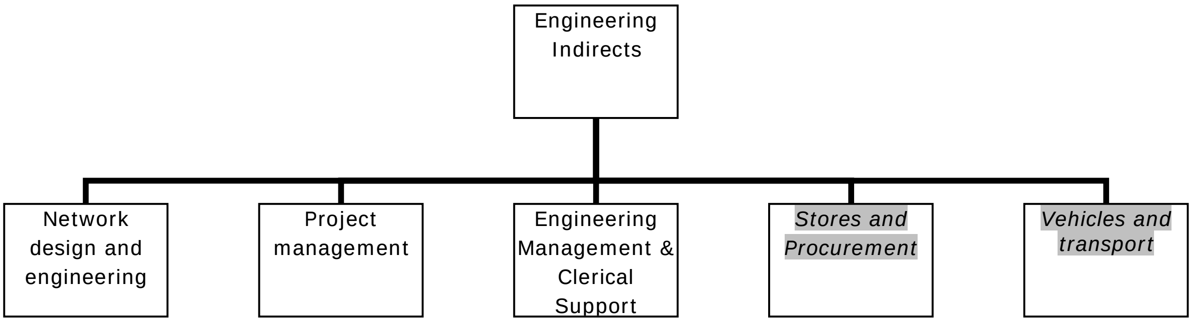
1.31. This grouping covers indirect costs which are, in part, driven by the level of network investment or network operating costs. The proposed Engineering Indirects building blocks are:

- Network design and engineering,
- Project management, and
- Engineering Management & Clerical Support.

1.32. All Engineering Indirects are as defined in the current RRP rules. Further consideration may be given to the inclusion or part inclusion of the following indirect costs:

- Stores and Procurement, and
- Vehicles and transport.

Figure 5 Building Blocks - Engineering Indirects



Above RPI Cost increases

1.33. All cost estimates should be made using today's costs inflated by RPI. No additional cost increases should be included. The cost increase building block will enable quantification of above RPI increases for each building block. This will be further split by changes in:

- internal labour,
- contracting rates, and
- equipment and material costs.

Interaction between building blocks

1.34. It is important that DNOs are able to quantify the interaction and dependencies between the different building blocks. This is to insure internal consistency of the total forecast and that trades offs between different building blocks are accounted for. For example, the interaction between I&M and the required level of asset replacement.

Building Blocks - Business costs

1.35. The building blocks for business costs are currently under development. Again the underlying assumption will be consistency with current RRP definitions. The output of the ongoing cost driver work will be used in defining the building blocks for the remainder of indirect costs as captured in RRP table 2.2.

Way Forward

Ofgem will look to establish a DNO/Ofgem working group to further develop the building blocks, including definitions, assumptions, and outputs for each building block. Final guidance for the high level forecast for network costs will be published by 15 May 2008.

Appendix 9 - Volume of DG connections by DSA

The table below sets out the volume of DG connections forecast by the DNOs for DPCR4 and the actual volume of DG that has connected in the first two years of DPCR4.

DG Connections

Table 1 - Volume of DG connections by DSA

	2005-06 to 2009-10 Forecast[10] (MW)	2005-06 & 2006-07 Actual[11] (MW)
CE NEDL	1152.9	14
CE YEDL	1097.4	33
CN East	865	5
CN West	69.7 - 309	10
EDF EPN	807.8	17
EDF LPN	335.4	0
EDF SPN	472	0
ENW	987 - 1530	9
SP Distribution	1437	43
SP Manweb	987	6
SEPD	248	6
SHEPD	866.7	9
WPD S Wales	261.4 - 455	6
WPD S West	175 – 315.8	8

[10] Electricity Distribution Price Control Review: Update October 2003 (124/03) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=16&refer=Networks/ElecDist/PriceCntrls/DPCR4
[11] Data is derived from price control revenue reports (forecast and detailed returns) which DNOs are required to provide to the Authority under standard condition 50 of the Electricity Distribution Licence.

Appendix 10 - Excluded services

1.1. Excluded services means those services provided by the licensee as part of its distribution business which, in accordance with Special Licence Condition A2 (Scope of the charge restriction conditions), fall to be treated as excluded services.

1.2. Service definitions are taken from Special Licence conditions A2, Appendix 1

Table 1 - List of excluded services

Excluded Service	**Service Definition**
ES1 - EHV New Connections	The service consisting of the distribution of units: a. to EHV premises that were not connected to the licensee's distribution system before 1 April 2005; or b. to premises connected before 1 April 2005 that become EHV premises by virtue of having their connection materially altered, subject to the licensee's agreeing with the Authority an appropriate offsetting adjustment to the value of PU or PE (being the amount set against that term in the part of Annex A of special condition B1 (Restriction of distribution charges: demand use of system charges) that applies to the licensee) as appropriate.
ES2 - Connections	The service consisting of the carrying out of works for the provision, installation, operation, repair or maintenance of electric lines or other electrical plant, but only insofar as such service is not remunerated through use of system charges or under charges made for legacy basic meter asset provision and the provision of data services in accordance with paragraph 1 of standard condition 36C (Basis of Charges for Legacy Basic Meter Asset Provision and the Provision of Data Services: Requirements for Transparency) or under charges made for the provision within its distribution services area of metering point administration services in accordance with paragraph 2 of standard condition 14A (Basis of Charges for Metering Point Administration Services: Requirements for Transparency).
ES3 - Revenue Protection	The service consisting of the provision of any revenue protection services pursuant to the terms of an agreement for use of system.

Excluded Service	**Service Definition**
ES4 - Charging Statement	The service consisting of the provision of any statement or report pursuant to: a. paragraph 7 of standard condition 4 (Use of System Charging Methodology); b. paragraph 8 of standard condition 4A (Charges for Use of System); c. paragraph 13 or 15 of standard condition 4B (Connection Charging Methodology); d. paragraph 7 of standard condition 14A (Basis of Charges for Metering Point Administration Services: Requirements for Transparency); or e. paragraph 7 of standard condition 36C (Basis of Charges for Legacy Basic Meter Asset Provision and the Provision of Data Services: Requirements for Transparency).
ES5 - Non-Trading Rechargeables (required by licence)	The service consisting of the relocation of electric lines or electrical plant (including the carrying out of any works associated therewith) pursuant to any statutory obligation (other than under section 9(1) or section 16 of the Act) imposed on the licensee.
ES6 - Non-Trading Rechargeables (not required by licence)	The service consisting of the moving of any electric lines, electrical plant or meters forming part of the licensee's distribution system to accommodate the extension, redesign or redevelopment of any premises on which the same are located or to which they are connected.
ES7 - Top Up/Security/Stand By	The service consisting of the provision of electric lines and electrical plant insofar as the same are required: a. for the specific purpose of enabling the provision of top-up or standby supplies or sales of electricity; or b. to provide a higher degree of security than is required for the purposes of complying with paragraph 1 of standard condition 5 (Distribution System Planning Standard and Quality of Service).
ES8 - Reactive Power	The service consisting of the transportation of reactive energy to premises with a power factor of less than 0.95, but only insofar as the charges for such services reflect the costs imposed on the licensee and are levied on the basis of the metered value of kVAr or kVArh transported to such premises.

Excluded Service	**Service Definition**
ES9 - Other excluded services	Any other service in relation to use of the licensee's distribution system insofar as it consists of the provision of a service (including electric lines or electrical plant) which is for the specific benefit of any third party who requests it and which is not made available by the licensee as a normal part of its distribution business within its distribution services area remunerated by use of system charges, or under charges made for legacy basic meter asset provision and the provision of data services in accordance with paragraph 1 of standard condition 36C (Basis of Charges for Legacy Basic Meter Asset Provision and the Provision of Data Services: Requirements for Transparency), or under any other charge in respect of the excluded services set out in paragraphs ESI to ESS and paragraph ES10.
ES10 - Excluded Metering	Any provision of a metering service other than legacy basic meter asset provision (as set out at paragraph 3 of standard condition 36 (Requirement to Offer Terms for Legacy Basic Meter Asset Provision)), which is not remunerated by use of system charges or under any other charge in respect of an excluded service set out in paragraphs ESI to ES9.