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Electricity Distribution Cost Review 2007 -2008

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Target audience: This document may be of particular interest to electricity distribution network operators, investors, analysts, consumer groups, individual consumers and other interested parties.

Overview:

This report summarises the reported network investment and operating expenditure for 2007-08 for the 14 electricity distribution network operators (DNOs) as provided in the annual Regulatory Reporting Pack (RRP) submissions. Annual regulatory reporting was implemented in 2004-05 to provide robust and consistent data for price control reviews.

This report includes our current view of the Regulatory Asset Value (RAV) for each DNO as at 31 March 2008. The RAV is one of the key elements in determining allowed revenue for the DNOs. The RAV as at 31 March 2009 will be finalised as part of DPCR5 when allowed revenues will be set for the five year period from 2010-11 to 2014-15.

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Context

Electricity Distribution Network Operators (DNOs) report annually to Ofgem on the costs they incur in operating, maintaining and improving their distribution systems.

This information provides trends of expenditure for each distribution system and informs the current electricity distribution price control review, DPCR5.

We are committed to publishing an annual report on cost data. While this report is the fourth of its kind, it is the third during the electricity distribution price control period from 1 April 2005 to 31 March 2010 (DPCR4).

The aim of the report is to present the key information on the DNOs' network investment and operating expenditure in a meaningful and user friendly format and to provide an indication of the performance of the DNOs.

Associated Documents

The following documents may be found on our website:

http://www.ofgem.gov.uk/Networks/ElecDist/Pages/ElecDist.asx

- Electricity Distribution Cost Review 2005-2006 (ref 18/07)
- Electricity Distribution Cost Review 2006-2007 (ref 289/07)
- Electricity Distribution Industry Activity Costs (ref 290/07a)
- Electricity Distribution Cost Review 2004-2005 (ref 263/05) - note this document sets out in its Appendices 1 and 2 the Price Control allowances for DPCR4
- Electricity Distribution Price Control Review- Price control cost reporting rules: Instructions and Guidance February 2008
- 2007-08 Electricity Distribution Quality of Service Report
- Electricity Distribution Price Control Review Final Proposals November 2004 (ref 265/04)
- Links to DNO regulatory accounts
- We will be publishing a version of Table 2.1 of the Regulatory Reporting Pack (RRP) in January 2009
- Distributed Generation Schemes Special Conditions D2 Electricity Distribution Price Control Review (ref 54/05).

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Summary

Ofgem regulates the 14 electricity distribution network operators (DNOs), who are all regional monopolies, to protect the interests of current and future consumers. Every year the DNOs provide Ofgem with data on their costs, according to our reporting guidelines. This report provides a summary of the key cost data for the DNOs for 2007-08 and the issues associated with this.

We use the data provided in the annual cost reporting submissions to better understand the DNOs' cost performance in preparation for and as part of distribution price control reviews and for monitoring performance against the assumptions made during those reviews. This data should allow us to perform price control reviews better and to protect customers' interests more effectively. More specifically we use the data to:

- monitor the level of network investment and associated outputs;
- provide the base data for benchmarking costs across DNOs and other cost assessment techniques during price control reviews; and
- ensure the Regulatory Asset Value (RAV), which forms an important component in setting allowed revenues, is rolled forward annually according to the rules set out in DPCR4 Final Proposals.

In the last price control review (DPCR4) we recognised that our work was made more difficult because we did not have robust and consistent data upon which to base our analysis. We also recognised that the requirement for a single historical data request during a price control placed too heavy a burden on the DNOs to produce data that their systems were not developed to provide. The process of annual reporting has not only improved the robustness and consistency of data but reduced the burden on DNOs to provide financial and other information at the time of a price control review.

Annual reporting has had additional benefits including the resolution of outstanding RAV issues throughout the price control period rather than just during the review prior to a new price control. This has meant that we are able to improve the quality of that work and smooth out the resourcing needs to complete the work.

We are also aware that the DNOs themselves have used some of the published data (see Associated Documents above) to compare themselves with their peers not only to improve consistency but also to drive cost reductions into their business where they appear inefficient.

Where we have identified inconsistencies in reporting we have sought to improve the data where possible and encouraged DNOs to improve their reporting systems as appropriate. We recognise and appreciate the progress that DNOs generally have made to improve the quality of the data provided in the annual submissions. We remain concerned, however, that there are still some inconsistencies in reporting and DNO data capture systems are not always adequate to collect accurately the data we require. Where we are aware this is the case, we will take account of the level of assurance we have about the accuracy of reporting in the price control review.

We consider that DNOs have had sufficient time to augment their reporting processes and systems in order to comply with the regulatory reporting requirements. We will therefore now be less accepting of repeated re-submissions to correct errors and differences of interpretations and we will look to take enforcement action should any licensee fail to meet the requirements of the relevant licence condition. If licence breach is proven, this may result in a financial penalty.

Notwithstanding the concerns we have with some aspects of the data submitted by some DNOs, we are of the view that the data we have will allow us to undertake more sophisticated analysis of costs and other associated information for DPCR5 than has been possible for previous reviews.

The 2008-09 RRP will provide the final data for the current price control review (DPCR5) which is setting the control for 2010 to 2015 and at this stage we place a high value on consistency of data. We therefore do not intend to make any significant changes to the RRP for 2008-09.

Our next electricity distribution cost report will cover the year ended 31 March 2009, the fourth of five years of the DPCR4 price control period. We currently intend to publish the cost report for 2008-09 in January 2010, after Final Proposals for the current price control review (DPCR5).

Key Performance Findings 2007-08

Over 2007-08 network investment across the DNOs increased by 19 per cent from 2006-07 levels although most DNOs indicated that the annual outturn has been below their own internal plans. We are in a period of high asset replacement as those assets originally constructed in the post war period near the end of their useful lives. The DNOs expect that asset replacement activity will increase over the rest of the current price control period and into DPCR5.

By contrast operating expenditure across the DNOs has remained relatively stable compared to the previous year with an increase in costs of less than one per cent. This overall stability in cost levels masks increases in costs at some DNOs and decreases for others.

However, overall capex within the DPCR4 period is still 13 per cent below our assumptions in setting the price control. DNOs forecast that total capex will be 4 per cent below our assumptions for the full five years of DPCR4. DNOs have highlighted a range of factors affecting their ability to deliver the increased capital investment plans during the early years of the period including delays in mobilising their contractors, shortages of skilled labour and management decisions to reduce volumes of work to meet costs. DNOs assure us that resources are now substantially in place to deliver spend in future years in accordance with their investment plans. Their success in doing this will be an important factor in our assessment of their capex submissions for DPCR5.

The provisional RAV figures have been set with only a small number of outstanding issues for resolution during the current price control review (DPCR5). Additions to RAV to date are 10.8 per cent below expectations at £4.4 billion. We anticipate total RAV additions (based on DNOs forecasts in the FBPQ) in DPCR4 will be £7.9 billion against an expected £8.2 billion, 4.3 per cent less than expected.

1. Overview of the process

Introduction

1.1. One of the key lessons arising from the last Electricity Distribution Price Control Review (DPCR4) was the importance of capturing historical data consistently on an annual basis to improve the quality of the data we use in setting the price control and to spread the burden of data capture over the whole price control period. We set out a timetable for implementing improved cost reporting arrangements in the DPCR4 Final Proposals and began the process of developing cost reporting guidelines at the start of the DPCR4 period.

1.2. The Final Proposals document set out the expectation that DNOs would implement a 'robust scheme for the categorisation of costs' and that they would support the cost reporting process.

1.3. After a period of initial development the first set of Price Control Review Reporting Rules (Rules) were published in April 2005 for the submission of data relating to the 2004-05 financial year. We published the first annual Cost Report in December 2006. These Rules have developed each year to incorporate the experience and lessons learnt from previous reviews. We have added new tables and data points where we require additional information and reduced the reporting where the data is not required.

1.4. This process allows us to get a better understanding of the costs and underlying policies of the electricity distribution network operators (DNOs) and enables comparison of actual expenditure to DPCR4 allowances. The annual cost reporting process and data submissions are informing the current distribution price control review, particularly the benchmarking of costs across the industry.

1.5. We reorganised the Rules for 2007-08 to make them more user friendly and incorporated some minor amendments to definitions which have, in the past, led to different interpretations of where to assign costs. We also made more fundamental changes to the Asset Data tables to assist our understanding of the drivers of network investment. We have issued further guidance for the 2007-08 submission around the classification of costs which has largely resolved outstanding issues such as in the reporting of fault repairs.

1.6. We have continued to investigate other areas where we identified there may be different interpretations of the rules to improve consistency and to monitor areas where costs have moved between early and final submissions of the RRP by DNOs.

1.7. We attach a high level of importance to the cost reporting process in DPCR4 (see paragraphs 7.86 and 7.87 of the Final Proposals[1] for example) and we expect continued further improvement in data quality in future years. The 2008-09 RRP will provide the final data for the current price control review (DPCR5) which is setting the control for 2010 to 2015 and at this stage we place a high value on consistency of data. We therefore do not intend to make any significant changes to the RRP for 2008-09. We expect the only changes we make will relate to formula errors in the RRP or to delete data that we are not utilising for DPCR5.

1.8. We have discussed with the DNOs our current intention of requesting an early submission of some RRP data for the 2008-09 financial year. This will allow us to include our analysis of that data in the Initial Proposals consultation document for DPCR5 in the summer of 2009.

Objectives

1.9. The RRP rules provide a detailed framework for the DNOs to report costs and other data on an annual basis. The prime objectives of the rules are to improve the robustness and consistency of cost data and avoid varying interpretations of definitions and reporting requirements. The DNOs are also required to provide a commentary to support the cost and other data presented and to explain any movements in the data from previous years.

1.10. It should be noted that the data in this report is extracted from the DNOs' submissions which have not been audited, although total costs are reconciled to the DNOs' audited regulatory accounts.

Comparability

1.11. Whilst the data submitted by the DNOs under the rules should be consistent with the definitions provided, there are a number of reasons why reported costs are likely to vary across DNOs including:

- structure of the DNO’s group, including related party service providers, recharging of corporate services and inter-DNO charging;
- management policies, both historical and current;
- different interpretations of the guidelines;
- legacy issues including pre-privatisation and previous ownership decisions; and
- different network sizes, structures and operating environments.

[1] Electricity Distribution Price Control Review Final Proposals November 2004 (ref 265/04)

1.12. Comparability adjustments have not been applied to the data in this report and we stress the data should not be used for comparison purposes without considering the above-mentioned factors.

Processes for 2007-08

1.13. The process we followed was similar to that for previous years. Following receipt of submissions from the DNOs in mid July 2008, we reviewed and analysed the data in depth to assess its compliance with the Rules, its robustness and consistency. We sent out questions to each of the DNOs and reviewed those responses prior to visiting each DNO.

1.14. Each DNO visit was structured along the same lines, with a generic agenda outlining our objectives with regard to discussing the RRP returns and the initial Forecast Business Plan Questionnaire (FBPQ) submitted in August. The FBPQs allow the DNOs the opportunity to present their best view of their expected costs and other data for the remainder of DPCR4 and for the whole of the DPCR5 period.

1.15. The DNOs' presentations covered a review of faults, inspections and maintenance, tree cutting, governance and capital expenditure programmes. These were valuable in understanding each DNO's business structure and practices, and the ways in which these impacted on costs during 2007-08.

1.16. This year we have placed increased emphasis on understanding the investment planning processes including the key assumptions and models used by the DNOs in developing their longer term forecasts for DPCR5. We have also explored the outputs that will be delivered by the forecast levels of investment. The development of investment output measures is one the key focuses for DPCR5.

1.17. Throughout the visits DNOs co-operated well and we have gained a better appreciation of each of their businesses. This should help us to regulate fairly and effectively.

Quality of submissions

1.18. DNOs have generally adapted their internal reporting systems and committed significant resources to the reporting process, including input from senior staff. Other DNO staff are generally becoming more aware of the data reporting requirements in the RRP and this has contributed to improving the robustness of the submitted data.

1.19. However we continue to have concerns about the ability of some DNOs to provide robust and comparable data in the form required. These concerns relate to:

- data capture systems that do not collect the data required to attribute costs accurately to specific assets and therefore management judgement is required to allocate those costs;
- the allocation of costs between businesses where services are shared between DNOs, and other businesses, within the same ownership group; and
- the visibility that DNOs have of some related party costs.

1.20. The review and visit process identified where DNOs needed to revise their original submissions. The resubmissions resolved a number of issues and minor inconsistencies in treatment. The amendments to Table 2.2 (Total Cost Matrix) of the RRP from first submission to the latest submission in November 2008 showed just 3.2 per cent of costs moved between cells in the table compared to 9.7 per cent in 2006-07 and 11.2 per cent in 2005-06. The reduction in cost movements between submissions suggests the DNOs were able to provide more accurate data in their initial submissions than in previous years.

1.21. We discussed the governance procedures for completion of the submissions during the cost reporting visits and we considered the systems and procedures described to us were generally thorough and should give a high degree of confidence that the numbers provided were broadly in accordance with the Rules.

1.22. After four years of annual reporting, we consider that DNOs have had sufficient time to augment their reporting processes and systems in order to comply with the regulatory reporting requirements. We will therefore now be less accepting of repeated re-submissions to correct errors and differences of interpretations. These should be resolved prior to the first formal submission. Should any licensee fail to meet the requirements of the relevant licence condition we will look to take enforcement action. If licence breach is proven, this may result in a financial penalty.

Ongoing work

1.23. We will make minor refinements to the definitions and guidance . The intention is to eliminate the inconsistencies identified this year in data reported by DNOs and to remove differences of interpretation and incorporate the outcome of the boundary surveys. We intend to issue the rules for 2008-09 in February 2009

1.24. Our next electricity distribution cost report will cover the year ended 31 March 2009, the fourth of five years of the DPCR4 price control period. We currently intend to publish the cost report for 2008-09 in January 2010, after Final Proposals for the current price control review (DPCR5).

1.25. During 2009 we intend to carry out further work to investigate the reasons behind the differences in reported costs for faults particularly for low voltage (LV) and high voltage (HV) underground cable faults.

Structure of this report

1.26. The rest of this report is structured as follows:
Chapter 2 - Commentary on year-on-year movement in costs

Chapter 3 - Expenditure against our assumptions underlying DPCR4 allowed revenue

Chapter 4 - RAV and pensions.

2. Cost Analysis - by activity

Chapter Summary

This chapter summarises the overall expenditure of the DNOs for the regulatory year 2007-08 and provides a review of costs compared to the previous two years. Costs are presented as reported in the RRP submissions.

2.1. Total costs have increased by £183m (6 per cent) in real terms in 2007-08 mostly due to an increase in gross load and non-load related expenditure. There has also been a decrease in pension deficit payments in the year of £79m.

2.2. The overall increase in costs varies greatly between the DNOs. Total costs for CN East rose £74m (31 per cent), mostly relating to gross load related costs and ENW costs rose £40m (18 per cent) due to increases in network investment and a one off atypical cost relating to the sale of the business.

2.3. In contrast total costs for both of Scottish Power's DNOs declined; SP Manweb's costs fell by £85m (29 per cent) and SP Distribution's costs fell by £31m (13 per cent). The reductions mostly related to a drop in the pensions deficit payments but in SP Distribution there was also a fall in load related costs.

Reported Costs 2007-08

2.4. We set out clear rules for the classification of costs into activities. These rules distinguish between "direct" activities which involves work on the physical network (such as replacing and reinforcing network assets, fault repairs etc) and "indirects" which do not (network design, call centre, finance and regulation, etc). For the purposes of this report we have grouped the "direct" activities between Network Investment (including Load and Non-Load Related expenditure) and Network Operating Costs (including Faults, Inspections & Maintenance and Tree Cutting).

2.5. Table 2.1 shows DNO costs in 2007-08 as reported in the RRP with some grouping of activities.

Table 2.1: Activity Costs on an RRP basis (2007-08 prices)

	Cash typical costs									
	Direct activities				Indirect activities					
2007-08	Load related (gross)	Non-load related (gross)	Non-operational capex	Network operating costs	Engineering indirects	Network/Investment support	Business support	Atypical cash costs	Pension deficit payments	**Total Distribution Business Cash Costs**
CN West	60	83	2	44	34	16	28	2	8	**276**
CN East	128	58	2	47	25	17	25	1	10	**314**
ENW	83	66	4	25	29	9	35	15	0	**266**
CE NEDL	46	43	4	27	17	10	19	0	22	**187**
CE YEDL	55	55	4	43	19	12	20	5	6	**219**
WPD S Wales	24	32	3	18	14	8	17	4	13	**135**
WPD S West	29	45	15	28	20	10	19	7	21	**193**
EDFE LPN	78	54	8	33	28	13	26	2	15	**257**
EDFE SPN	48	62	7	36	21	14	24	3	16	**232**
EDFE EPN	108	79	19	60	42	23	37	3	4	**375**
SP Distribution	49	68	3	24	27	14	23	2	2	**212**
SP Manweb	47	72	3	28	23	14	23	1	0	**210**
SSE Hydro	17	28	3	14	15	11	19	2	0	**110**
SSE Southern	94	49	8	46	30	22	29	3	27	**307**
Total	**865**	**793**	**85**	**473**	**344**	**194**	**344**	**52**	**143**	**3293**
2006-07	**700**	**699**	**95**	**468**	**326**	**209**	**340**	**53**	**222**	**3110**
2005-06	**709**	**590**	**71**	**451**	**309**	**219**	**352**	**17**	**300**	**3018**

Notes:
- Normal pension costs are included within the typical and atypical costs reported.
- 2005-06 and 2006-07 costs have not been amended for prior year adjustments reported in the RRP, although these are expressed here in 2007-08 prices.

2.6. A full analysis of DNOs' expenditure by activity, reconciled to the expenditure in their regulatory accounts, will be published on on our website in January 2009 (see Associated Documents section above).[2]

[2] The data for 2007-08 (and the prior year comparators) includes pensions and related party margins. The figures are therefore on a different basis to those reported in Table 2.1 of the RRP. Table 2.1 shows total typical cash costs on an activity basis (i.e. before indirect costs are capitalised by the DNO).

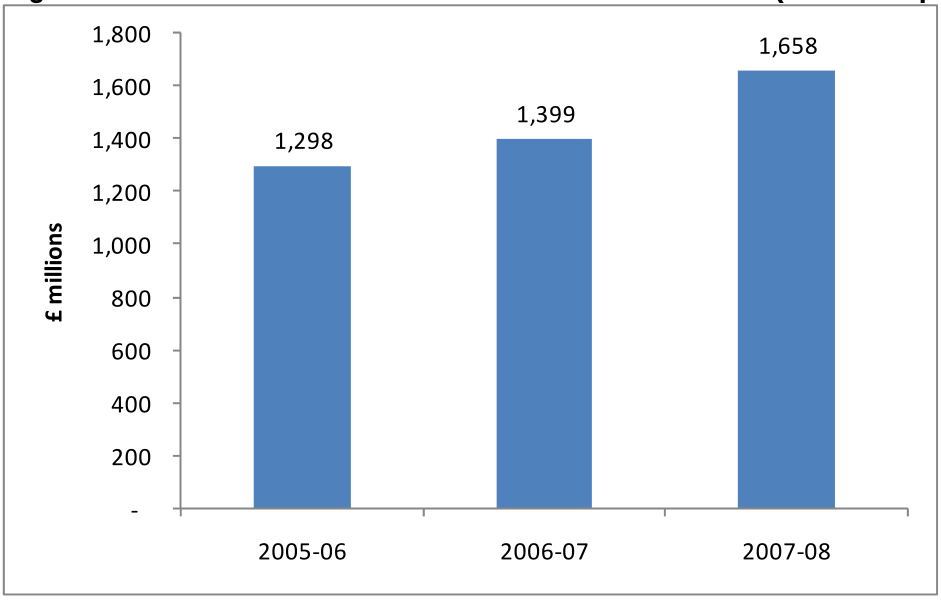
Typical costs include the normal level of employer pension contributions (but not pension deficit payments) and exclude rates, licence fees, transmission exit charges and depreciation. Atypical cash costs and pension deficit payments are shown in total. Atypical events are specific events or incidents that are not expected to recur regularly under normal circumstances due either to their size, nature or severity. These include for the quality of service interruptions incentive scheme all severe weather events that meet the relevant exceptionality requirement defined in annex B of special condition C2 of the electricity distribution licence. With certain exceptions (e.g. early retirement deficit costs) restructuring and atypical costs are allowable in computing additions to RAV.

Network Investment

2.7. Network Investment is the total expenditure on network assets excluding overheads, less all income received from customers for new connections and reinforcement as determined under the charging arrangements. It only includes direct costs associated with load and non-load related new and replacement assets as defined in the RRP Rules (see Associated Documents section above)

2.8. Figure 2.1 shows the reported Network Investment for the three years to 2007-08. Overall network investment has increased by 28 per cent since 2005-06. While the majority of DNOs have achieved material increases in network investment expenditure, most companies have indicated that their outturn expenditure has been below their own internal plans. We are in a period of high levels of asset replacement as the assets originally built in the post war period are nearing the end of their useful lives. We expect, and DNOs have forecast, that non-load related asset replacement expenditure will increase over the coming years and well into the DPCR5 period.

Figure 2.1 Network Investment 2005-06 to 2007-08 (2007-08 prices)



2.9. The largest reported increases in capex were for CN West (£77m - 71 per cent) and SSE Southern (£31m - 28 per cent). The only DNO with a reduction in Network Investment was SP Distribution although WPD S Wales and SSE Hydro costs only increased by around £2m year-on-year.

2.10. It is worth noting that real increases in input prices had a significant impact on overall levels of investment expenditure and the underlying growth in investment volumes has been lower over 2007-08 than the cost movements may suggest..

Factors affecting delivery of Network Investment

2.11. DNOs have highlighted a range of factors affecting their ability to deliver the increased capital investment plans during the early years of the period including;

- delays in mobilising their contractors,
- adverse weather diverting resources from investment to fault repairs
- shortages of skilled labour and,
- management decisions to reduce volumes of work to meet costs.

2.12. The majority of DNOs have now developed new processes and introduced new ways of working regarding the procurement and management of external contractors. In most cases DNOs have now reached a level of resourcing, internal and external, required to deliver their capital expenditure programmes for the remainder of DPCR4.

2.13. Additional issues DNOs have highlighted include:

- Reduced volumes to manage budgets following increasing units costs and contracting rates ;
- restricted availability of plant from manufacturers with long production and delivery times; and
- network access constraints both because of work on the Distribution and Transmission network (planned outages).

2.14. DNOs indicated that the increases in copper and steel prices, amongst other things such as increasing demand, are driving a large increase in the ex-factory unit costs of distribution equipment. Primary transformer and cable prices have increased significantly. They suggest that any efficiency gains made during DCPR4 may be more than offset by increased unit costs although the decline in economic activity in the last quarter has brought significant reductions in many of the relevant commodity prices.

2.15. The majority of DNOs commented that due to increasing demand for resources, both internal and external labour costs are increasing. In addition, all DNOs highlighted an unprecedented increase in manufacturing lead times particularly for transformers and certain voltages of underground cable and switchgear. DNOs indicated this has been driven by a large increase in worldwide demand for distribution equipment of which the DNO (and Great Britain in general) requirements account for a relatively small share. Again DNOs noted that as the result of recent economic condition the trend is now reversing.

Initial forecast for DPCR5

2.16. In August 2008 the DNOs provided their initial Forecast Business Plan Questionnaire (FBPQ) responses which in total forecast an increase in net network investment of 82% for the DPCR5 period compared to DPCR4.

2.17. These initial FBPQ responses were based on analysis the DNOs undertook earlier in the year and therefore do not reflect the latest economic conditions. In the majority of cases the forecasts were based on assumptions that economic growth would continue at historical trend rates. In practice economic activity has declined in the last quarter and there have been significant reductions in many of the relevant commodity prices. At the time of the costs visits many DNO were already seeing a major downturn in connection activity.

2.18. We discussed the underlying assumptions and approaches behind the FBPQs in detail at this year's cost visits. Forecasts for expenditure on the primary network were generally built up from individual identifiable schemes where possible (bottom up), with top-down modelling used to forecast expenditure requirements further out (towards the end of DPCR5). Expenditure on the secondary network was built up from top down modelling or on the perceived need to maintain or reduce equipment fault rates. In some cases bottom up forecasting appeared to be unconstrained by any top down view or any consideration of overall system risk. In particular we would look for DNOs to quantify the effect that their plans have on system risk and to justify any changes.

2.19. Further details and analysis of the DNOs' initial FBPQ are provided in the DPCR5 policy document and associated appendices [3].

Asset data

2.20. As part of last year's cost review we placed an increased focus on the quality of the asset data and age profiles provided to us by the DNOs. This was to ensure a consistent and robust data set for analysing DPCR5 capex submissions and to avoid the prolonged process of data cleansing that was required in the early stages of DPCR4.

2.21. As result of those discussions we improved the definitions and guidance for reporting asset data for 2007-08. DNOs have also been asked to resubmit asset addition and disposal information for 2005-06 and 2006-07 taking account of the new definition and guidance.

[3] Electricity Distribution Price Control Policy Paper (159/08)

2.22. The following comments summarise our observations on DNOs' progress with asset data.

Asset risk management and the development of output measures

2.23. Given all DNOs have all now achieved PAS55 compliance our focus has moved from understanding the DNOs' approach to asset risk management to getting more information on the outputs that are delivered by network investment.

2.24. The DNOs need to develop good output measures for a number of reasons including to allow us to assess efficient investment requirements, to encourage DNOs to improve the way they plan and operate the networks with a focus on the outputs that will be delivered and to ensure that the DPCR5 settlement provides value for money to customers.

Asset condition data and the development of Health Indices

2.25. The majority of companies have adopted or are developing health indices to enable asset condition related risks to be quantified and deterioration rates to be monitored and forecast. The development of health indices allows the DNOs to better assess the performance of the network and to plan the replacement requirements for the network assets.

2.26. Initial work has revealed those aspects of asset condition affecting reliability and asset life which can be identified by inspection and maintenance. When identified, asset condition assessment criteria are established and embedded in data collection systems allowing population during asset inspections. Several companies appear to be well advanced in this. But since intrusive asset condition inspections seldom take place at less than 12 year cycles for the majority of assets (and particularly for the higher volumes of LV and HV assets) it will be some time before asset condition databases are fully populated, and even longer before deterioration trends can be fully assessed.

2.27. Nevertheless, at primary voltage levels some inspections take place on a shorter inspection cycle and more condition information should be available for these. A small number of DNOs are also undertaking specific asset condition surveys in order to populate the condition data rather than relying on normal inspection and maintenance intervals.

2.28. Although some companies propose to use analytical techniques based on health indices and the development of deterioration rates and associated algorithms to convert health indices to future investment need, this is still in the early stages of development and there is limited experience in using this approach.

Investment schemes

2.29. The majority of DNOs have good processes and polices for developing scheme papers and sanctioning investment. A small number of DNOs achieve leading practice, including undertaking comprehensive post investment appraisals, benchmarking of unit costs and deliverables, providing £/MW of increased network capacity, producing comprehensive cost benefits analysis including the quantification of risk and producing consistent, well-documented, company-wide multi-step approval processes.

2.30. For the majority of DNOs there is a material degree of scheme churn (i.e. different schemes being undertaken from those set out in forecasts prepared during the last price review), particularly for load-related expenditure. In some cases system reinforcement and asset replacement schemes have been deferred until after the end of DPCR5 whilst new schemes for the current period have been introduced. In addition scheme phasing, the scope of work and forecast costs have also varied from earlier predictions.

Quality of Service Investments and Initiatives

2.31. Most DNOs plan to continue investing in network remote control to reduce customer interruptions and minutes lost and to obtain benefits from the 'interruption incentive scheme'[4]. Some companies are investing in additional protection schemes to minimise the consequence of faults and are incorporating automatic sequential switching programmes within their network control systems (network automation).

2.32. The majority of DNOs have been operating or are currently introducing operational practice aimed at restoring the highest number of customers possible within a given time following a supply interruption, usually around 60 minutes, in order to reduce customer minutes lost. Initiatives include: identification of optimum network switching points (over and above normal open points), the use of larger switching teams (up to 4 people per fault), live line working, 'pinging' of mobile phones to determine closest available resources and the use of dedicated fault teams for repair and restoration within defined areas.

2.33. Some companies see less scope for further improvements in quality of service output measures over the remainder of the price control period as 'easy wins' are already fully implemented, although this also depends on the DNOs' current performance against their interruption incentives scheme targets. Uncertainty

[4] The interruption incentive scheme has symmetric annual rewards and penalties depending on each DNO's performance against their targets for the number of customers interrupted per 100 customers (CI) and the number of customer minutes lost (CML). There are also telephony incentives based on the results of ongoing customer surveys on DNOs' telephony performance.

around targets and incentive rates for DCPR5 is also an issue in assessing benefits of investment at the tail end of DCPR4.

2.34. For further detail on DNOs' quality of service performance, please see our 2007-08 Quality of Service Report (165/08)[5].

Distributed Generation Incentive

2.35. The connection of relevant distributed generation (DG) to distribution networks under the new incentive mechanisms (from 1 April 2005) has been slower than expected. To date 442 MW of distributed generation has been connected under the DG incentive (26 MW in 2005-06,140 MW in 2006-07 and 261 in 2007-08).

2.36. Some DG connections are still being processed under contractual arrangements put in place before 1 April 2005 although the number of connections made on those terms will decrease over time. See Associated Documents above for more details of the DG scheme.

Operating Expenditure

2.37. For the purposes of this report 'Operating Expenditure' is used to describe the activities grouped under Network Operating Costs, Engineering Indirects, Network Support, Business Support and Non-Operational Capex.

2.38. Figure 2.2 shows the total reported Operating Expenditure for the three years to 2007-08. Overall costs in real terms have increased by less than 1 per cent in 2007-08.

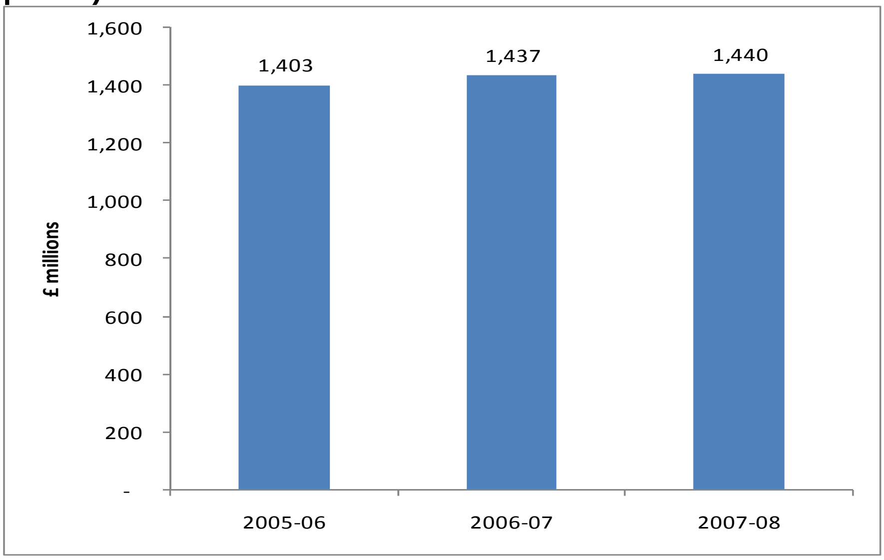
2.39. The overall stability in costs masks some significant differences in cost movements between DNOs (i.e. some DNO costs have increased while others have fallen) but also results from differences in movements in costs across the activity groupings listed above. Engineering Indirect costs have increased overall by around 6 per cent in real terms while those for network support and non-operational capex have decreased significantly. Cost for network operating costs and for business support costs have remained relatively stable.

2.40. EDFE EPN reported the largest increase in operating expenditure in 2007-08 of £20m (13 per cent), driven mainly by engineering management, clerical support activity and project management activity CN East reported the largest decrease in opex of £12.8m (10 per cent) due mainly to reduced expenditure on IT and Telecoms, even though they also reported the largest increase in network investment

[5] Available on our website.

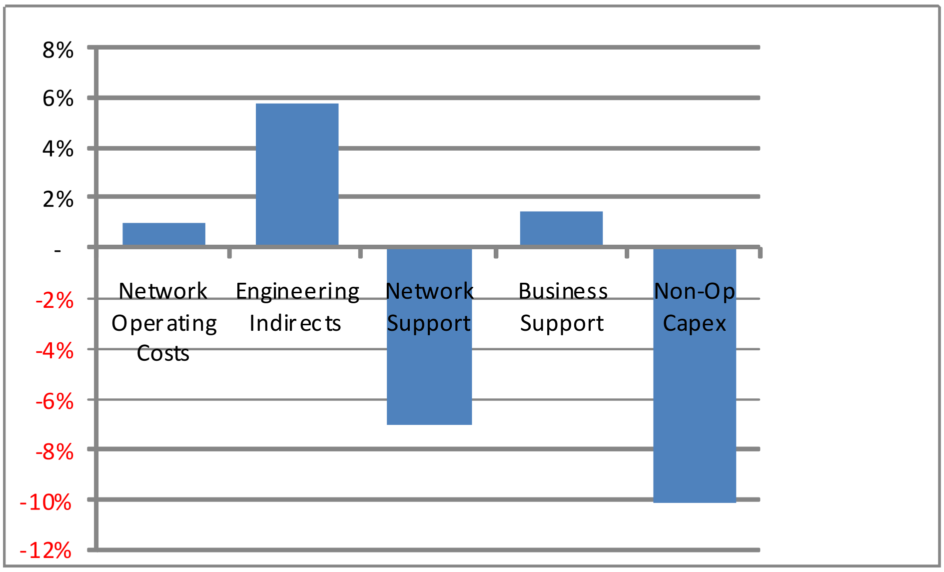
costs (72 per cent). The next largest fall in reported costs was at SP Manweb where they fell £8.7m (9 per cent).

Figure 2.2 Reported Operating Expenditure 2005-06 to 2007-08 (2007-08 prices)



2.41. The following sections provide further details of those costs movements by DNO split into the cost groupings listed above. Figure 2.3 shows how these cost groups have changed compared to 2006-07.

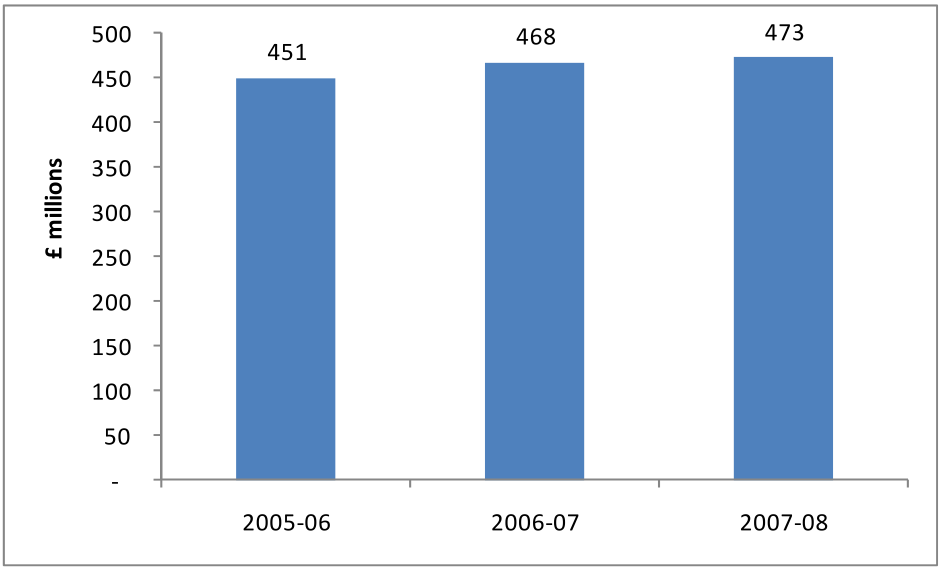
Figure 2.3 Change in Reported Costs compared to 2006-07.



Network Operating Costs

2.42. For the purposes of this report, Network Operating Costs are the costs defined as Faults, Inspections & Maintenance and Tree Cutting in the RRP Rules. Figure 2.3 shows the total expenditure on Network Operating Costs for the three years to 2007-08. This shows that these costs have only increased by about 1 per cent real terms since 2006-07.

Figure 2.4: Network Operating Costs 2005-06 to 2007-08 (2007-08 prices)



2.43. The overall increase masks significant differences across the DNOs. Network operating costs for SSE Southern increased by £7.6m (20 per cent) in real terms. The costs for EDFE LPN decreased by £4.2m (11 per cent).

Faults

2.44. Overall fault costs (excluding exceptional weather events) decreased in real terms by £1m (less than 1 per cent) from 2006-07. The most significant increases in costs were for CE where costs increased by £5.4m (13 per cent) and SSE where they increased by £3.3m (12 per cent).

2.45. The cost increases at CE were largely due to multiple weather related events in the first quarter of 2008, predominantly affecting LV mains services in the YEDL area and non-Quality of Service faults[6] in both areas.

2.46. The cost increases at SSE were primarily due to a fault on the submarine cable connecting the Isle of Wight and for LV mains Consac cable fault costs.

2.47. Costs reported by Central Networks fell by £7.6m in real terms primarily because of a change in allocation of costs from faults to non-load related network investment resulting from a review of costs by CN after the 2006-07 report.

Inspections and Maintenance

2.48. Overall inspections and maintenance (I&M) costs reduced in real terms by £1m (1 per cent) on 2006-07 levels. The largest increases in costs occurred at CN West £2.8m (32 per cent) and SSE Southern £3.3m (32 per cent).

2.49. The increase in costs at CN West resulted mostly from full mobilisation of a new contractor and higher activity on the HV plant assets.

2.50. The increased costs in SSE Southern related primarily to a change in interpretation of the rules whereby pressure assisted cable costs were reported against Inspections & Maintenance in 2007-08 but against Faults in 2006-07. SSE costs also increased by around £0.8m to implement the requirements of Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002 (as amended).

2.51. Theft of copper from DNOs' sites is again reported to be increasing across the country and companies are spending a significant amount of time and resources on repairs and additional site security. This is having a negative impact on routine I&M volumes and is increasing expenditure.

2.52. Substation electricity is unmetered electricity used in the DNOs' substations and the costs are reported within the Inspections and Maintenance category of the RRP. Not all DNOs treat these costs the same way. Some DNOs pay the incumbent supplier whilst for the remainder unmetered substation electricity is accounted through the losses incentive for assessing revenues. The amounts are not significant and totalled £4.8m in 2007-08 spread across six DNOs. This compared to £6.8m spread across nine DNOs in 2006-07. Four DNOs reported no substation electricity costs this year that had in 2006-07 and one DNO reported costs where they reported none the previous year.

[6] Faults not covered by the Quality of Service RIGs (see associated documents)

Tree cutting

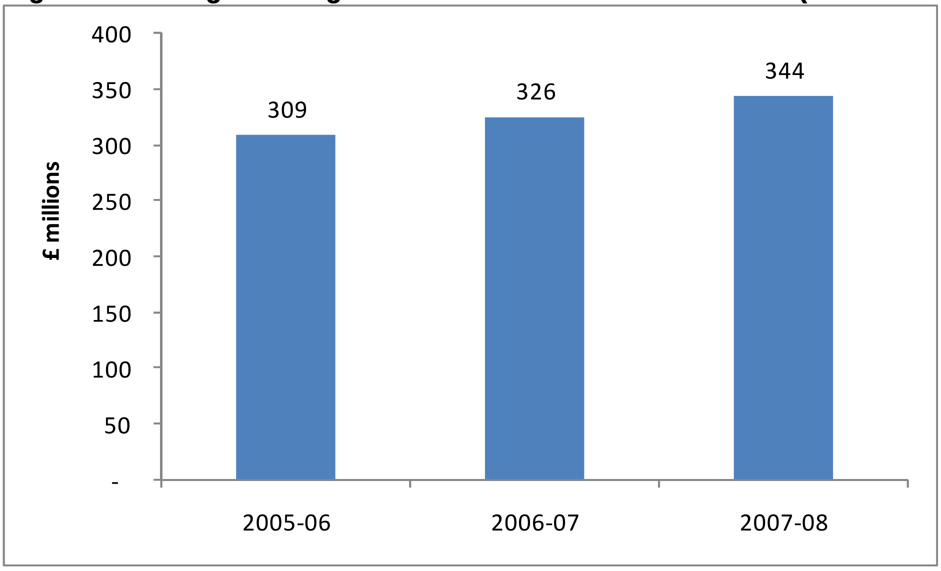
2.53. Tree cutting costs increased by £6.8m (10 per cent) in real terms in 2007-08 compared to the previous year. Key reasons for the increase include expenditure to comply with new legislation[7] and to reduce tree related faults (one of the main causes of faults in severe weather).

2.54. Tree cutting costs increased in most DNO groups except CE where they fell by £1.9m (13 per cent). The primary reason for the fall in costs was the restricted outage availability resulting from the flooding in the CE YEDL area in June 2007.

Engineering Indirects

2.55. Engineering Indirects are the activities defined as Network Policy, Network Design, Project Management and Engineering Management & Clerical Support (EMCS) as defined in the RRP Rules. Figure 2.4 shows the total expenditure on Engineering Indirects for the three years to 2007-08.

Figure 2.5: Engineering Indirects 2005-06 to 2007-08 (2007-08 prices)



2.56. Engineering Indirect costs have increased in real terms by £19m (6 per cent) in 2007-08 mostly in the activity of Engineering Management & Clerical Support (EMCS) which increased by £17.5m (10 per cent). Network Design (ND) and Project Management (PM) costs also increased by around £12m (10 per cent). Network

[7] Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002 (as amended).

Policy costs reduced by £11m mostly resulting from a redefinition in the rules whereby IFI costs are now separately captured.

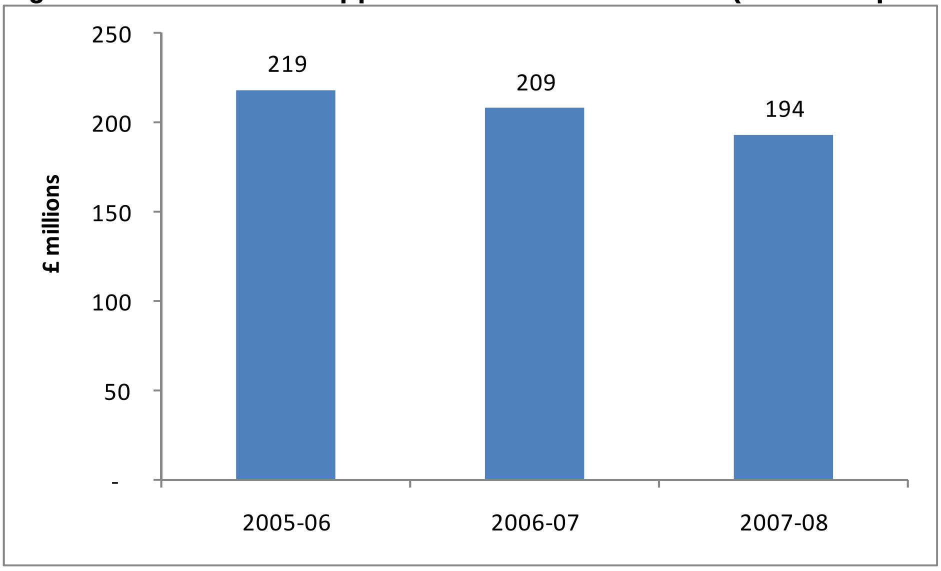
2.57. The largest value increases in Engineering Indirects occurred at EDFE where costs increased by £19m (26 per cent) and SP where costs increased by £4m (9 per cent). The key reasons given for the increases in costs at both DNOs were additional headcount to deal with the ramping up of the network investment activity and reorganisation of the functions concerned.

2.58. The only DNO group to report a notable reduction in real costs overall was ENW where costs reduced by £4.6m (16 per cent). The majority of the decrease was for EMCS resulting from efficiencies and reduction in related party margins. In addition Network Policy costs reduced by £1.5m mostly related to the reallocation of IFI costs.

Network Support

2.59. Network Support includes Control Centre, System Mapping, Call Centre, Stores, Vehicles & Transport and Health, Safety & Operational Training activities. Figure 2.5 shows the total expenditure on Network Support for the three years to 2007-08.

Figure 2.6: Network Support 2005-06 to 2007-08 (2007-08 prices)



2.60. Overall Network Support costs reduced by £15m (7 per cent) in 2007-08. The prime reason for the fall in costs was a change in the definition of procurement costs which are, from 2007-08, reported under Business Support. This resulted in a reduction of £10m in reported Network Support costs.

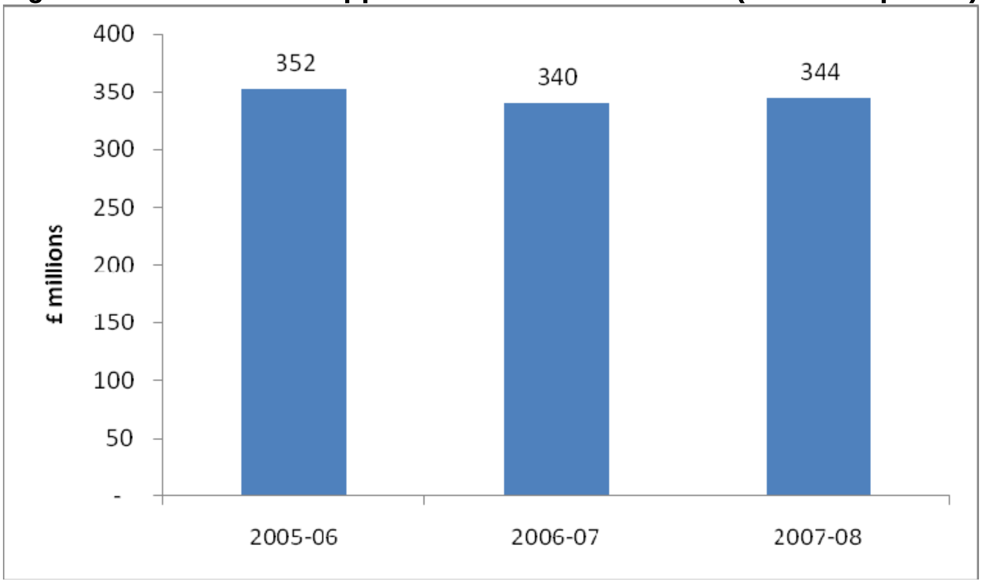
2.61. Only SSE showed increased costs overall of £1m (8 per cent), relating to increases in Vehicles & Transport, for increased numbers of vehicles and petrol prices, and Health, Safety & Operational Training relating to increased training costs and a misallocation in 2006-07.

2.62. The largest reductions, excluding the changed rules for reporting procurement costs, were at ENW where costs fell £3m (24 per cent) in real terms. Call Centre costs reduced primarily due to organisational changes and procurement costs (£1m) which were reallocated to Finance & Regulation.

Business Support

2.63. Business Support costs include IT & Telecoms, Property Management, HR & Non-Operational Training, Finance & Regulation and CEO etc as defined in the RRP Rules. Figure 2.6 shows the total expenditure on Network Support for the three years to 2007-08.

Figure 2.7: Business Support 2005-06 to 2007-08 (2007-08 prices)



2.64. Overall Business Support costs increased by £5m (1 per cent) in real terms. Of that increase £10m relates to the reclassification of procurement costs leaving a decrease in real terms of £5m (1 per cent).

2.65. Central Networks are the only DNO group to show a significant reduction in Business Support costs overall at £8m (13 per cent). The main reduction in costs was for IT at CN East following a review of a major service contract for telephony and to a lesser degree HR costs at both DNOs.

2.66. The DNOs showing the largest increases in Business Support costs, excluding the change in reporting of procurement costs, were ENW at £4m (14 per cent) and

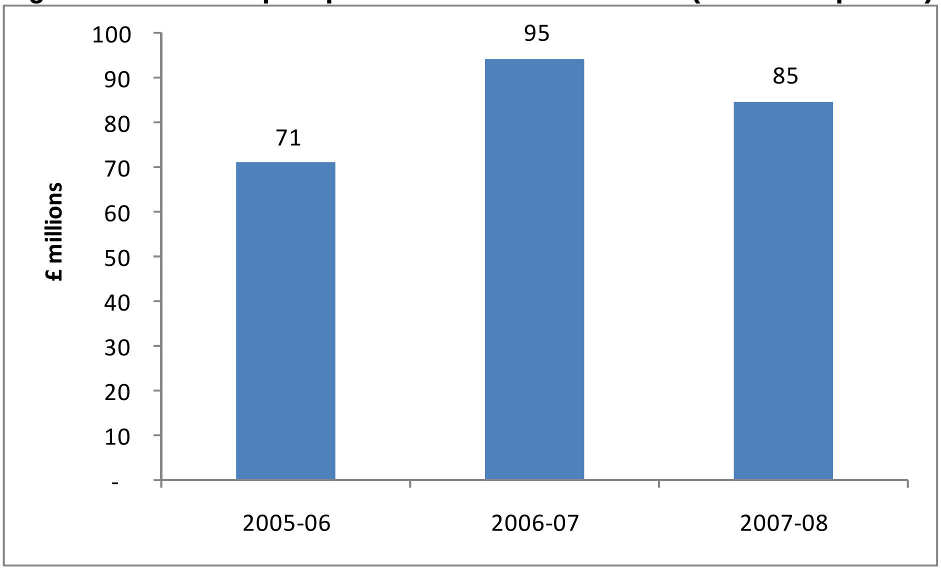
EDFE at £9m (12 per cent). The increases in ENW relate to a change in margins obtained by a related party and additional divisional recharges. The increase in costs at EDFE related partly to additional requirements for property and accrual releases.

2.67. Insurance costs have remained the same as for 2006-07 in real terms. There have been some movements between insurance categories but these relate mostly to changes in the interpretation of definitions

Non-Operational assets

2.68. For regulatory cost reporting purposes, the Non-Operational New and Replacement Assets cost category includes expenditure on capital items for use of the distribution business which are not distribution system assets, such as office buildings, computer hardware and some software, vehicles and small tools and equipment.

Figure 2.8: Non-Op Capex 2005-06 to 2007-08 (2007-08 prices)



2.69. Non-Operational capex decreased by £10m (10 per cent) in real terms on 2006-07 levels. The largest reductions in non-operational capex were at SP down £6.4m (54 per cent) and SSE down £4.3m (down 28 per cent). EDFE EPN reported an increase in costs of £7m (62 percent) while EDFE SPN reported a fall of £3m (27 per cent).

2.70. The reduction in overall Non-Operational Capex was due principally to a £11m reduction in reported non-operational IT expenditure. Most companies have ongoing programmes to replace information systems. Companies generally aim to avoid peaks and troughs of expenditure, although some DNOs had undertaken comprehensive IT replacement projects and therefore significant costs were incurred in 2006-07. The major reductions were at CE (down 70 per cent), WPD (down 60 per cent) and SP (down 38 per cent).

2.71. Some DNOs own their vehicle fleets whereas others lease them. Specialist vehicles tend to be purchased by all DNOs. In the year vehicle purchase costs increased by £1m (4 per cent). Single year data is not always representative of real changes in the cost base and are more likely to relate in differences in the replacement cycle of vehicles.

2.72. The only other significant movement in non-operational asset costs was for small tools & equipment where the costs increased by £1.6m (10 per cent)

3. Cost Analysis - DPCR4 Basis

➔ Chapter Summary

The purpose of this chapter is to compare costs for 2007-08 and the DPCR4 period to date with what was expected at the time DPCR4 allowed revenues were set. The actual costs are reported in the basis set out in Appendix 1 of the DPCR4 Final Proposals document.

Reported expenditure in 2007-08 against DPCR4 assumptions

3.1. Tables 3.1 and 3.2 show the capital expenditure[8] and operating expenditure for 2007-08 compared to the average annual DPCR4 allowance.

3.2. The tables show that DNOs have underspent against our capex assumptions by £24m (2 per cent) while they have overspent our opex assumptions by £88m (13%). A comparison across the tables shows that only SSE Hydro underspent against both our capex and opex assumptions. Both Central Networks' DNOs, CE NEDL and WPD S West have overspent against our capex and opex assumptions in setting DPCR4 allowed revenues.

Table 3.1: Capital Expenditure for 2007-08 on a DPCR4 Basis

	Actual	Allowance	Over / under spend to allowance	Over / under spend to allowance
	£m	£m	£m	%
CN West	138	130	8	6%
CN East	146	129	18	14%
ENW	112	121	-9	-7%
CE NEDL	80	73	7	9%
CE YEDL	92	97	-5	-5%
WPD S Wales	54	51	2	5%
WPD S West	76	75	1	1%
EDFE LPN	109	116	-7	-6%
EDFE SPN	108	123	-15	-12%
EDFE EPN	180	180	-1	-0%
SP Distribution	100	97	3	3%
SP Manweb	102	105	-2	-2%
SSE Hydro	53	55	-2	-4%
SSE Southern	124	146	-22	-15%
Total	**1474**	**1499**	**-24**	**-2%**

[8] Capex is calculated in accordance with Appendix 1 to the Final Proposals and includes Load-related new connections and reinforcement and Non-Load non-fault new and replacement assets, both net of customer contributions, and a proportion of other direct and indirect activity costs (see Table 2.1) excluding all pension costs

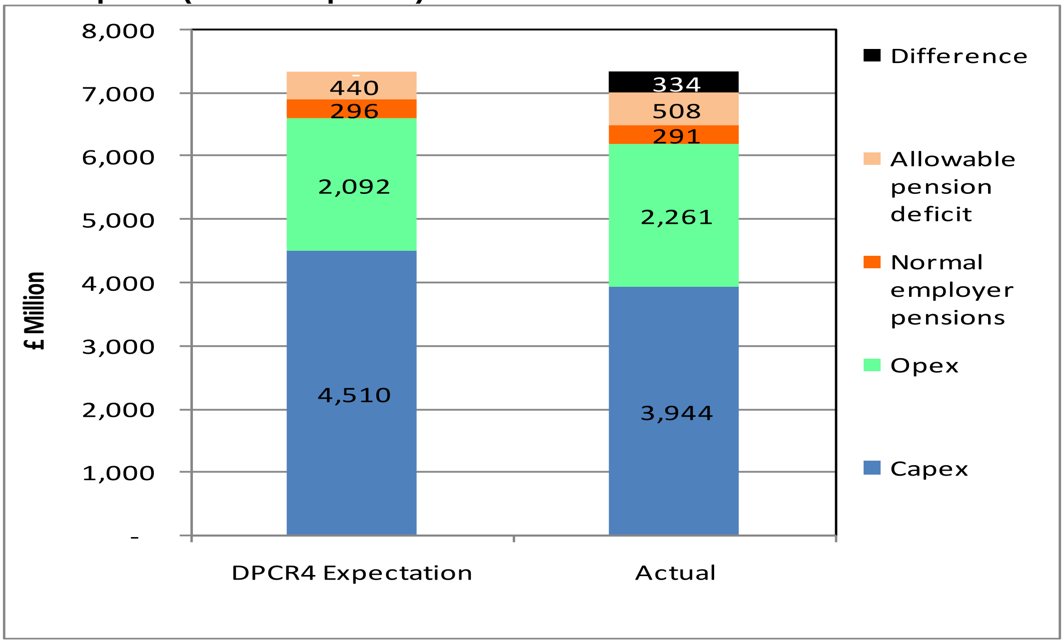
Table 3.2: Operating Expenditure for 2007-08 on a DPCR4 basis

	Actual Gross Opex	Disposals & excluded service adjustment	Actual Net Opex	DPCR4 allowance	Over/under spend to allowance	Over/under spend to allowance
	£m	£m	£m	£m	£m	%
CN West	69	-3	67	55	12	22%
CN East	65	-3	62	58	4	7%
ENW	63	-17	45	53	-7	-14%
CE NEDL	41	-1	41	39	2	6%
CE YEDL	60	-1	59	46	12	27%
WPD S Wales	33	-0	32	36	-4	-11%
WPD S West	51	-0	51	44	8	17%
EDFE LPN	61	-3	58	47	11	23%
EDFE SPN	60	-2	58	45	13	30%
EDFE EPN	106	-4	102	73	28	39%
SP Distribution	48	-3	45	50	-5	-10%
SP Manweb	48	-1	47	41	6	13%
SSE Hydro	32	-0	32	34	-2	-6%
SSE Southern	72	-1	72	62	10	16%
Total	**810**	**-39**	**770**	**682**	**88**	**13%**

Cumulative DPCR4 expenditure (2005-06 to 2007-08)

3.3. This section discusses the performance of the DNOs on a DPCR4 basis for the three years of that price control to date. Figure 3.1 shows overall performance against the price control cost assumptions on a cash basis.

Figure 3.1: Cost on DPCR4 basis 2005-06 to 2007-08 compared to DPCR4 assumption (2007-08 prices)



3.4. Figure 3.1 shows for all DNOs the cumulative expenditure in the three years of DPCR4 to 31 March 2008 is around £0.3bn (5 per cent) below the expected total expenditure for the three years. The majority of that underspend relates to capital expenditure.

3.5. Under DPCR4 rules it should be noted that opex overspends represent an additional expense for DNOs' shareholders, whereas capex underspends are shared with consumers through the capex rolling incentive mechanism. The sharing factor varies across the DNOs, ranging from 29% (EDF) to 40% (SSE).

Capital Expenditure

3.6. Table 3.3 below shows total capital expenditure (excluding all pension costs) to date compared to our DPCR4 assumptions for the three years for each company and the percentage under/over spend.

Table 3.3: Cumulative Capital Expenditure compared to our DPCR4 assumptions (2007-08 prices)

	Actual	Actual	Actual	Allowance	Over/under spend to allowance	Over/under spend to allowance
	2005-06	2006-07	2007-08	DR4 to date	DR4 to date	DR4 to date
	£m	£m	£m	£m	£m	%
CN West	118	135	138	392	0	0%
CN East	94	119	146	387	-29	-7%
ENW	93	91	112	363	-68	-19%
CE NEDL	65	69	80	219	-5	-2%
CE YEDL	99	80	92	292	-20	-7%
WPD S Wales	48	51	54	155	-2	-1%
WPD S West	73	77	76	224	1	0%
EDFE LPN	90	103	109	349	-47	-13%
EDFE SPN	96	73	108	374	-96	-26%
EDFE EPN	117	140	180	542	-105	-19%
SP Distribution	77	92	100	292	-24	-8%
SP Manweb	94	101	102	314	-17	-6%
SSE Hydro	38	43	53	167	-33	-20%
SSE Southern	95	99	124	439	-122	-28%
Total	**1,197**	**1,273**	**1,474**	**4,510**	**-566**	**-13%**

3.7. Overall capex for 2005-06 to 2007-08 is 13 per cent below our DPCR4 assumption. EDFE LPN, EDFE EPN, EDFE SPN, ENW, SSE Southern and SSE Hydro have all spent significantly less than our assumptions. Given that we set unprofiled capex allowances at DPCR4, it is not surprising that there would be some underspend in the early part of the period while the DNOs ramp up their expenditure followed by higher expenditure in the latter years.

Operating Costs

3.8. Table 3.5 shows the operating expenditure to date compared to our DPCR4 assumptions for the three years. The table shows that overall DNOs are overspending and that the overspend is higher in 2007-08 than in previous years.

Table 3.5: Cumulative operating costs against our DPCR4 assumptions (2007-08 prices)

	Actual	Actual	Actual	DPCR4 allowance	Over/under spend to allowance	Over/under spend to allowance
	2005-06	2006-07	2007-08	DR4 to date	DR4 to date	DR4 to date
	£m	£m	£m	£m	£m	%
CN West	57	64	67	169	19	11%
CN East	64	62	62	180	9	5%
ENW	54	45	45	163	-18	-11%
CE NEDL	39	42	41	117	5	4%
CE YEDL	49	53	59	141	20	14%
WPD S Wales	34	33	32	110	-11	-10%
WPD S West	46	51	51	133	16	12%
EDFE LPN	47	55	58	142	18	12%
EDFE SPN	58	56	58	144	28	20%
EDFE EPN	83	93	102	223	55	25%
SP Distribution	57	49	45	152	-1	-0%
SP Manweb	58	49	47	126	28	22%
SSE Hydro	32	31	32	104	-9	-9%
SSE Southern	58	70	72	189	10	5%
Total	**738**	**753**	**770**	**2092**	**169**	**8%**

3.9. The table shows significant differences across the DNOs of the amount of over/under spend against allowances. Only four DNOs show an underspend against allowances totalling £39m while the other ten DNOs show overspends totalling £208m.

Capital Expenditure forecast outturn DPCR4

Table 3.6: Capital expenditure forecast outturn for DPCR4 (2007-08 prices)

	Actual 05-06 to 07-08	Forecast 08-09 to 09-10	Allowance	Over/under spend to allowance	Over/under spend to allowance
	£m	£m	£m	£m	%
CN West	392	231	650	-27	-4%
CN East	359	268	643	-17	-3%
ENW	295	250	603	-57	-10%
CE NEDL	214	162	365	12	3%
CE YEDL	272	217	486	4	1%
WPD S Wales	153	103	257	-1	-1%
WPD S West	225	147	373	-1	-0%
EDFE LPN	302	232	581	-46	-8%
EDFE SPN	277	294	620	-49	-8%
EDFE EPN	437	432	902	-33	-4%
SP Distribution	269	201	486	-16	-3%
SP Manweb	297	217	523	-9	-2%
SSE Hydro	134	132	277	-11	-4%
SSE Southern	318	346	731	-67	-9%
Total	**3944**	**3233**	**7497**	**-321**	**-4%**

3.10. Across the five years of DPCR4 DNOs are forecasting to outturn 4 per cent below the DPCR4 allowance with individual DNOs ranging from 10 per cent below to 3 per cent above. These forecasts depend on DNOs achieving their own forecasts for the remaining two years of DPCR4.

3.11. In addition to the difficulties they have had in ramping up their capex spend DNOs have highlighted a number of other reasons for lower expenditure relative to their allowances such as;

- reduced asset replacement due to improved asset management,
- the exclusion of related party margins and connections margins from affiliates, increases in connections income; and
- load increases not materialising as forecast.

4. Pensions and RAV Issues

Chapter Summary

This chapter presents our review of pensions and the Regulatory Asset Value (RAV), including gearing on a RAV basis.

4.1. Pension contributions to date in DPCR4 exceeded our DPCR4 assumptions by 9 per cent as four DNOs have previously made one-off deficit repair payments. We expect further payments of this nature following the triennial revaluations of nine pension schemes in 2007-08. Increases in normal contributions will also arise which are expected to offset the current underspend reported by some DNOs.

4.2. Additions to RAV to date are 10.8 per cent below expectations at £4.4 billion. We anticipate total RAV additions (based on DNOs forecasts in the FBPQ) in DPCR4 will be £7.9 billion against an expected £8.2 billion, 4.3 per cent less than expected.

4.3. Over DPCR4, gearing (being net debt to RAV) has declined from 50 per cent overall to 44 per cent, compared to the nominal 57.5 per cent applied at the price control. We have revised net debt to include all inter-company loans and working capital balances in line with our latest view. Low gearing in part reflects the slower ramp up of capital expenditure and the debt structures adopted by the individual ownership groups.

Pensions

Background to regulatory treatment

4.4. Under our Price Control Pension Principles set out in 2003[9], we allow the DNOs to recover their actual pension costs, provided that they are economic and efficiently incurred, at the subsequent price control. For DPCR4 an ex ante allowance was set for pension costs with an ex post adjustment to true these up to the actual cash costs incurred by DNOs in the period. Allowed pension costs are treated as 42.3 per cent as opex and 57.7 per cent as capex for the purpose of setting revenue allowances.

[9] Developing Network Monopoly Price Controls May 2003 (54/03)
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=41&refer=Networks/Policy

4.5. There have been a number of significant changes in the UK pension environment since 2003. We considered it appropriate therefore, to review the working of our pension principles. To do this we issued a consultation in August 2008 - *Price Control Pension Principles*. In it and a subsequent seminar in October, we consulted on a number of matters. That consultation process is ongoing through DPCR5 and is addressed in our December 2008 Policy Paper[10]

Pension costs

4.6. As shown in Table 4.1, overall actual contributions up to the end of 2007-08 exceed expectations by 9 per cent as four DNOs (CN East, CN West, ENW and SP Manweb) made additional one-off deficit contributions in the first two years of DPCR4 that were not in their forecasts. In 2006-07, SP Manweb made a substantial one off deficit repair contribution and no further deficit repair payments are expected. United Utilities (now ENW) made a substantial one-off pension payment which was treated as paid on 1 April 2005; it comprised not only a deficit repair payment but an advance payment for five years worth of normal contributions. This was all accounted for in 2005-06 and not spread over the DPCR4 period. In 2007-08, no DNO has made noticeable lump-sum payments to repair pension fund deficiencies.

4.7. For all except one of the English and Welsh DNOs, the triennial valuations of their pension schemes as at 31 March 2007 were completed in 2008. The impact of increases in normal contributions will come through in 2008-09. Only CE Electric and WPD have made incremental annual deficit repair contributions in 2007-08 but we expect 2008-09 data will show further contributions by the other DNOs.

4.8. For the five years of DPCR4, total pension costs are now forecast at £1.3 billion compared to allowances of £1.2 billion.

[10] Electricity Distribution Price Control Review Policy paper December 2008 (159/08)

Table 4.1: Cumulative pension costs calculated on a DPCR4 basis against allowances (2007-08 prices)

	Actual	Actual	Actual	DPCR4 allowance	Over/under spend to allowance	Over/under spend to allowance
	2005-06	2006-07	2007-08	DR4 to date	DR4 to date	DR4 to date
	£m	£m	£m	£m	£m	%
CN West	53	9	12	57	17	31%
CN East	39	6	12	46	10	23%
ENW	89	0	0	57	33	57%
CE NEDL	20	19	21	62	-2	-3%
CE YEDL	11	11	12	36	-2	-6%
WPD S Wales	7	13	11	35	-5	-13%
WPD S West	11	17	15	51	-8	-16%
EDFE LPN	23	26	23	77	-5	-6%
EDFE SPN	19	22	19	72	-13	-19%
EDFE EPN	13	17	13	43	-0	-1%
SP Distributio	6	6	6	17	0	1%
SP Manweb	17	83	6	55	50	91%
SSE Hydro	4	5	5	14	-0	-1%
SSE Southern	32	34	34	106	-6	-6%
Total	**344**	**267**	**189**	**730**	**69**	**9%**

4.9. All of the DNOs are maintaining measures to manage their exposure to the risk-risk based element of the levy they are subject to under the Pension Protection Fund scheme.

RAV Issues

4.10. RAV is the value ascribed by Ofgem to the capital employed in the licensees' regulated distribution business (the 'regulated asset base'). It is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. It is important to licensees, as the revenues they are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

4.11. The amounts shown in Table 4.2 are provisional and our view of RAV. RAV will be finalised as part of DPCR5 and set out in the Initial Proposals document in July 2009.

Additions to RAV

4.12. In 2007-08, £1.6 billion was added to RAV, which for the first time matched expectations. This brings the total additions in DPCR4 to date to £4.4 billion. Using unadjusted DNO forecasts, it is anticipated that total RAV additions in DPCR4 will be £7.9 billion against an expected £8.2 billion, 4.3 per cent less than expected.

4.13. Our current view of the additions to each DNO's Regulatory Asset Value is shown in Table 4.2 below. In calculating the RAV rolled forward from 1 April 2005, we have applied the methodology set out in Appendix 1 of the final proposals document.

4.14. In reviewing reported costs we have been particularly concerned to ensure:

- that key boundaries between activities whose costs enter RAV in different percentages have been respected (e.g. direct capex, direct and indirect opex);
- that only the time-sheeted labour costs of staff physically working on network assets have been included in direct costs except for non-operational assets;
- that costs and capital contributions associated with providing connections to the licensee's distribution system (including any contributions retained under the previous tariff support arrangements) have been fully included in the data for the distribution business, whether provided by the licensee or by a related party (in accordance with the definitions in the licence);
- the identification of adjustments to 2005-06 and 2006-07 reported costs arising from clarification to the treatment of certain costs and the resolution of various boundary issues;
- the correct treatment of transactions with related parties (e.g. captive insurers);
- that revenue earned by a related party fulfilling an obligation of the licensee and acting on behalf of the licensee does not count as external turnover in considering related party margins; and
- that treatment of excluded services costs and revenues has been consistent with the licence conditions and final proposals (which require a RAV adjustment for the difference between forecast and actual excluded services revenue).

4.15. We have rolled forward the provisional RAV on the same basis for all licensees. Adjustments to 2005-06 and 2006-07 values have been made following work to clarify the treatment of costs direct/indirect labour boundary costs. These adjustments have been reflected through revisions to the opening RAV balances signalled last year. Where additional information has become available, the rules clarified, or where errors have been picked up, the DNO's opening RAV has also been restated.

RAV roll forward

4.16. Table 4.2 below shows our current view of the RAV roll forward at 31 March 2008, showing additions in 2007-08. The provisional RAV figures in the table have been discussed with the DNOs concerned, although in some cases DNOs have not agreed the figure shown. The RAV will be finalised as part of DPCR5 and set out in the Initial Proposals document in July 2009.

Table 4.2: RAV roll forward - Ofgem provisional view

	Balance b/f 1 April 2007	Memo: Additions per Final Proposals	Additions Actual	Deprecia-tion	Balance as at 31 March 2008	Balance as at 31 March 2008 (see note)
	£m (2007/08)					£m(nominal)
CN West	1239	**136**	146	(96)	**1289**	**1316**
CN East	1171	**133**	153	(95)	**1229**	**1256**
ENW	1146	**128**	112	(92)	**1166**	**1191**
CE NEDL	744	**82**	92	(60)	**777**	**793**
CE YEDL	982	**101**	99	(77)	**1004**	**1026**
WPD S Wales	676	**56**	60	(59)	**677**	**692**
WPD S West	872	**82**	84	(70)	**887**	**905**
EDFE LPN	1098	**127**	122	(88)	**1132**	**1156**
EDFE SPN	800	**134**	119	(63)	**856**	**874**
EDFE EPN	1363	**182**	187	(106)	**1444**	**1475**
SP Distribution	1389	**97**	103	(134)	**1359**	**1388**
SP Manweb	992	**111**	106	(76)	**1022**	**1044**
SSE Hydro	822	**56**	56	(62)	**816**	**833**
SSE Southern	1566	**161**	144	(130)	**1580**	**1613**
Total	**14862**	**1585**	**1583**	**(1207)**	**15238**	**15564**

Notes:

Opening RAV balances have been increased by prior year adjustments of £13 m as noted below net of depreciation

The RAV balance at 31 March 2008 has been calculated using the average of the RPI for March & April 2008

Columns may not cast due to roundings

4.17. Across the industry, actual RAV additions match the expectations at DPCR4 for the first time in three years, as DNOs have ramped up capital expenditure. In 2005-06 and 2006-07 spend was 15 per cent and 14 per cent lower than the price control allowances respectively. While some DNOs, notably Central Networks, CE-NEDL, WPD and SP Distribution are now exceeding our DPCR4 assumptions, RAV additions are still notably lower than expected at EDFE SPN, SP Manweb and SSE Southern reflecting their capital investment activity and ENW (by 12 per cent) reflecting partly their investment activity and partly the impact of their up front pension payments in 2005-06. RAV balances brought forward at 1 April 2007 have increased by £13m following the outcome of work on boundaries and other amendments to conform treatment across the industry.

4.18. A rolling capex incentive mechanism was included in the final proposals. This, in conjunction with a sliding scale mechanism (to accommodate a range of approaches between DNOs in relation to capital expenditure projections), will allow DNOs to keep/ (bear) a percentage of the value of their under/ (over) spend for a full period of five years. The industry is currently forecasting to underspend its capex allowances by approximately 4 per cent (excluding pension costs) over the DPCR4 period.

Gearing to RAV

4.19. Table 4.39 below shows each DNO's gearing (defined as closing net debt to RAV), which is our primary measure of gearing for DPCR5. Following our review of the definition of net debt and interest set out in our open letter dated 5 December 2008[11], we have revised both net debt and gearing for current and previous years. Net debt is reported at the licensee level and now includes other inter-group debt and working capital balances; gearing ratios for 2007 have been amended.

4.20. The gearing ratio used in the DPCR4 cost of capital was 57.5 per cent compared to the overall industry weighted average gearing at the time of 44 per cent (45 per cent in 2006-07 and 50% in 2005-06). DNOs' individual debt and gearing varies depending on the company's own financing structures within individual ownership groups. Reported net debt and gearing is only that of the licensee. During the year, overall net debt has increased by £218m in real terms after falling £280m in 2006-07.

4.21. Some DNOs have made inter-company loans which at a licensee level distorts the reported net debt and gearing. We are currently reviewing and consulting on whether it is appropriate to include these loans in net debt - see 4.19 above.

[11] Clawback of tax benefit due to excess gearing - open letter
http://www.ofgem.gov.uk/Networks/Policy/Documents1/Tax_Clawback_Open_Letter.pdf

Table 4.3: Gearing to RAV

	Net Debt	RAV	Gearing at 31 March		
	as at 31 March 2008 £m (nominal)		2008 %	2007 %	2006 %
CN West	670	1,316	51%	50%	53%
CN East	475	1,256	38%	37%	41%
ENW	518	1,191	43%	38%	47%
CE NEDL	397	793	50%	48%	47%
CE YEDL	512	1,026	50%	49%	69%
WPD S Wales	117	692	17%	23%	11%
WPD S West	211	905	23%	32%	38%
EDFE LPN	458	1,156	40%	51%	57%
EDFE SPN	531	874	61%	68%	75%
EDFE EPN	694	1,475	47%	57%	64%
SP Distribution	699	1,388	50%	54%	57%
SP Manweb	549	1,044	53%	50%	54%
SSE Hydro	244	833	29%	33%	37%
SSE Southern	760	1,613	47%	39%	44%
TOTAL	**6,835**	**15,564**	**44%**	**45%**	**50%**

4.22. The table does not include guarantees provided by licensees for parent company debt of £1.95m jointly by SP Distribution and by SP Manweb's immediate parent company and with SP Transmission.

4.23. The debt shown in Table 4.3 above does not include the impact of derivatives hedging of either currency or interest rates at the year end.

Appendices

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Appendix 1 - Response and Questions

We welcome views on the type and format of information that users of this report would find useful.

Please send your comments to:

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Appendix 2 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[12]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[13].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[14]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[15]

[12] entitled "Gas Supply" and "Electricity Supply" respectively.
[13] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[14] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[15] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[16] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[17] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[16] or persons authorised by exemptions to carry on any activity.
[17] Council Regulation (EC) 1/2003

Appendix 3 - Glossary

We have produced a glossary of terms relating to Electricity Distribution Cost Review. These can be found in Appendix 2 to the following document:

Electricity Distribution Price Control Review Price control cost reporting rules: Instructions and Guidance March 2008:

http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/CostRep/Documents1/Cost%20Reporting%20Rules%202007-08.pdf

Appendix 4 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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