

Electricity Distribution Cost Review 2004/05

December 2005

Summary

This report sets out operating cost and capital expenditure data for the 14 electricity distribution network operators (DNO) for the year ended 31 March 2005. It also shows Ofgem's current view of the Regulatory Asset Value (RAV) for each DNO as at 31 March 2005. The RAV will be finalised at the next price review.

This is the first annual report on DNO costs based on the cost reporting process developed during DPCR4. In Ofgem's view, this process has been a successful first step on the path to DPCR5. Nonetheless further improvements have been identified to the process for 2005/06 data.

The next report will set out 2005/06 data, including more detail than provided this year. Ofgem's current expectation is that this will be published in January 2007.

Table of contents

1. Introduction	1
2. Background on the 14 Electricity DNOs.....	2
3. Consistency and Comparability of Data.....	4
Consistency.....	4
Comparability	4
Process for 2004/05	5
4. Industry Performance	7
Operating Costs.....	7
Capital Expenditure.....	9
Quality of service	11
Summary RAV roll forward	11
Future RAV calculations	13
Gearing to RAV	14
5. DNO Summaries.....	15
Central Networks West plc.....	16
Central Networks East plc.....	19
United Utilities Electricity plc	22
Northern Electric Distribution Limited	24
Yorkshire Electricity Distribution plc.....	26
Western Power Distribution (South Wales) plc.....	28
Western Power Distribution (South West) plc.....	30
EDF Energy Networks (EPN) plc	32
EDF Energy Networks (LPN) plc	34
EDF Energy Networks (SPN) plc	36
SP Distribution Ltd	37
SP Manweb plc.....	39
Scottish Hydro-Electric Power Distribution Ltd	41
Southern Electric Power Distribution plc.....	43
6. Ongoing Work.....	45

1. Introduction

- 1.1 All electricity distribution licensees (or Distribution Network Operators, DNOs) are required to report annually to Ofgem on the costs of operating, maintaining and improving their distribution systems. Over time this information will show the trend of expenditure on each distribution system.
- 1.2 Ofgem is committed to publishing an annual report on cost data for all DNOs and this report is the first of its kind. The aim of the report is to present the key information on the DNOs' operating and capital costs in a meaningful and user-friendly format.
- 1.3 We welcome any comments or suggestions for improving the content or format for future reports.
- 1.4 Any comments on this report should be sent by the end of April 2006 to:

Bill McKenzie
Senior Manager - Finance and Regulatory Reporting
Ofgem
9 Millbank
London
SW1P 3GE

Email: william.mckenzie@ofgem.gov.uk

- 1.5 Any questions on this document should, in the first instance, be directed to Bill McKenzie at the contact details above or telephone 020 7901 7220.

2. Background on the 14 Electricity DNOs

- 2.1 At privatisation, the Public Electricity Suppliers (PESs) were responsible for both the distribution and supply of electricity, taking the place of the former regional electricity boards. With the introduction of competition in supply, it was important to ensure that all supply businesses, both new and old, had fair access to the distribution networks.
- 2.2 The Utilities Act 2000 introduced separate licences for distribution and supply, and required that these be held by separate legal entities.

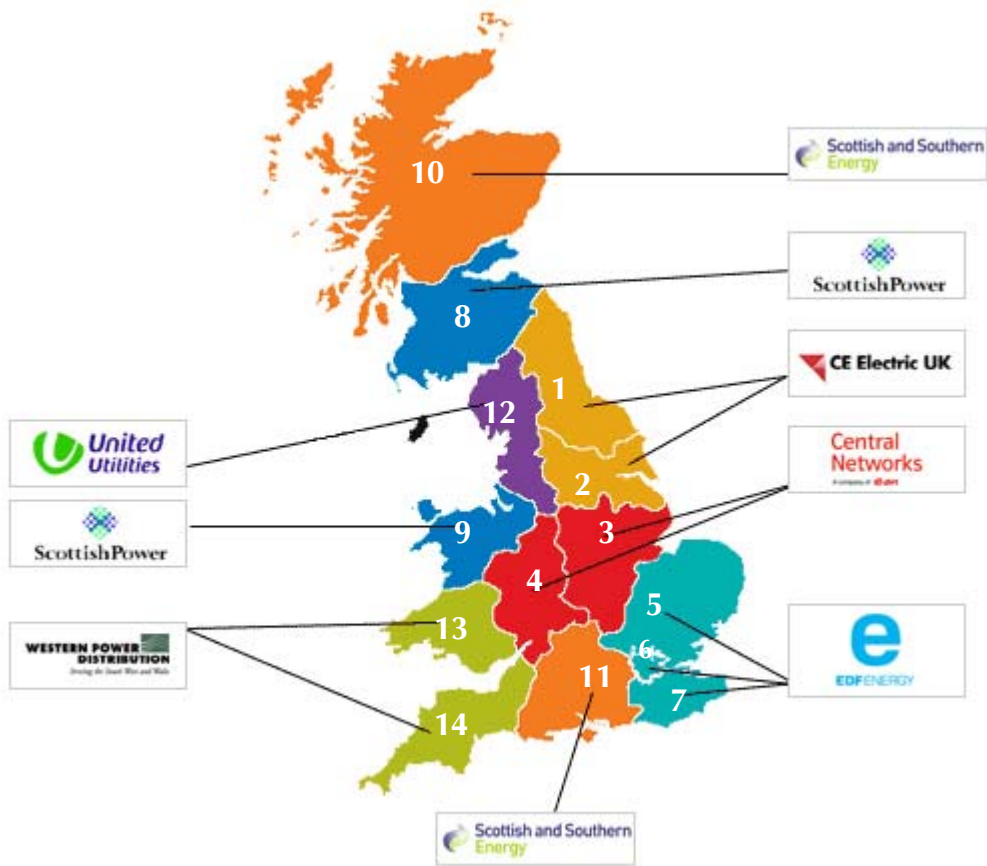
Distribution

- 2.3 DNOs are responsible for local distribution of electricity along overhead wires and through underground cables. This includes responsibility for ensuring that customers have a reliable electricity supply. After a number of corporate acquisitions, the 14 distribution licenses were owned by seven separate companies (see Map) for the whole of the year ending 31 March.

How much does distribution cost the customer?

- 2.4 Electricity distribution charges account for around £3 billion annually and make up around 20 per cent of customers' electricity bills.
- 2.5 For a typical domestic electricity customer, based on consumption of 3300 kWh of electricity a year, the distribution element of their bill is approximately £60.

Map of Great Britain showing the Geographical Areas of the 14 Distribution Network Operators



Name in the report	Name on Map
1. CE NEDL	CE Electric UK
2. CE YEDL	CE Electric UK
3. CN East	Central Networks
4. CN West	Central Networks
5. EDFE EPN	EDF Energy
6. EDFE LPN	EDF Energy
7. EDFE SPN	EDF Energy
8. SP Distribution	Scottish Power
9. SP Manweb	Scottish Power
10. SSE Hydro	Scottish & Southern Energy
11. SSE Southern	Scottish & Southern Energy
12. UU	United Utilities
13. WPD S Wales	Western Power Distribution
14. WPD S West	Western Power Distribution

3. Consistency and Comparability of Data

3.1 In April 2005, Ofgem published Price Control Review Reporting Rules (the rules) setting out how DNOs should report 2004/05 cost information.

Consistency

3.2 The rules provide a framework for the DNOs to report accurate and consistent information to Ofgem, including a standard reporting and commentary pack and instructions on how to complete it.

3.3 The objectives of the rules are to:

- ◆ improve robustness and consistency of cost data reported to Ofgem;
- ◆ reduce the burden on DNOs to provide financial and other information at the time of a price control review; and
- ◆ avoid varying interpretations of definitions and reporting requirements.

3.4 DNOs and Ofgem recognise it is important to have a robust structure in place for monitoring performance in the period 2005 – 2010 (DPCR4) and to provide consistent data for the next review (DPCR5).

Comparability

3.5 Ofgem recognise that whilst the data submitted by the DNOs under the rules should be consistent with the definitions provided, there are a number of reasons why costs will vary across DNOs including:

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

- 3.6 Comparability adjustments have not been applied to the data in this report and Ofgem stresses the data should not be used for comparison purposes without taking into consideration the above-mentioned factors.

Process for 2004/05

- 3.7 Following submission of data in July 2005, Ofgem visited each of the DNOs to assess the robustness and consistency of the information provided. This involved discussion of the ways in which the submissions were prepared, business structures and practices. The meetings have all been constructive and considered beneficial to both the DNOs and Ofgem.
- 3.8 For 2004/05, DNOs have, to varying degrees, used estimations and attributions to provide the information required as, given the timing of the cost reporting process and its development, their systems were not structured to deliver data in the format prescribed in the rules.
- 3.9 All the DNOs committed significant effort to the process and Ofgem acknowledges the work required in the preparation of data and information in accordance with the rules for this first year. The work required an average of around 15 person-months per group.
- 3.10 Taking account of the data collection issues noted above, the overall quality of the Regulatory Reporting Pack (RRP) completion was an encouraging start.
- 3.11 The Ofgem reviews, the visits and DNOs own post visit reviews identified the requirement to amend and refine the original submissions across the industry. The resubmissions resolved a number of issues and inconsistencies in treatment and comparability has improved. Work is continuing on analysis of the data. From our discussions with DNOs, where apparent inconsistencies remain, these generally arise for the reasons in paragraph 3.5 above.
- 3.12 Ofgem expects all DNOs will learn from completion of the packs in 2004/05 and subsequent discussions and will be able to submit more robust data next year. Notwithstanding the scope for improvement throughout the sector, some companies' submissions in 2004/05 had specific weaknesses, and will need to improve to reach an acceptable standard in 2005/06. Central Networks has

faced particular difficulties as a result of its decision not to retain full access to the accounting records and staff in place in 2004/05 in the West. Some DNOs have provided insufficient visibility into the costs of related parties. In view of the importance placed on the cost reporting process in DPCR4 (see paragraphs 7.86 and 7.87 of the Final Proposals¹ for example), Ofgem is confident that further improvements in data quality will be delivered in future years.

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

4. Industry Performance

4.1 This section sets out the overall performance of the electricity distribution industry and includes data to represent operating and capital expenditure across the DNOs, for 2004/05, there are three different definitions of operating and capital expenditure being used:

- ◆ companies' own accounting (Table 4.2 and chapter 5), which is useful to compare to previous years;
- ◆ DPCR4 basis, which is useful to compare 2004/05 to allowances for 2005-10 (Table 4.1 for operating costs); and
- ◆ DPCR3 basis, used to calculate the Regulatory Asset Value (RAV) for 2004/05 as the final year of DPCR3 but which will not be used in future (Table 4.3).

The differences between definitions include variations in capitalisation of indirect costs, fault repair costs and pensions.

Operating Costs

4.2 The table below shows operating costs for year ended 31 March 2005 (the last year of the DPCR3 period) on the same basis as the DPCR4 operating expenditure (opex) allowances. It also shows the DPCR4 allowances (see Appendix 1).

4.3 In 2004/05, on a DPCR4 basis, the level of overall operating costs (excluding all pensions, rates, licence fee and depreciation but including atypicals) across the industry are 6% higher than the allowances for the first year of DPCR4. Table 4.1 shows which companies appear to be in a relatively strong position to out-perform their allowances over the next five years and those with challenges ahead to achieve greater efficiencies. The year has been one in which the companies have been preparing and revising their plans to focus on achieving efficiency savings in DPCR4. To varying degrees, all DNOs are investing in information technology and network automation to increase network performance. There is increased spending on tree cutting to reduce tree related

faults, one of the main causes of faults in severe weather. Exceptional weather events reported by half the DNOs represent around 2% of total operating costs.

Table 4.1: Operating costs (excluding all pensions, rates, licence fee and depreciation)

year ended 31 March	Actual	DPCR4 allowance				
	2005	2006	2007	2008	2009	2010
£m (02/03 prices)						
CN West	52	49	48	46	45	44
CN East	52	52	51	50	48	48
UU	60	48	46	45	43	42
CE NEDL	32	34	33	33	32	32
CE YEDL	42	41	40	40	39	39
WPD S Wales	26	32	31	31	30	30
WPD S West	37	38	38	37	37	36
EDFE LPN	46	41	40	40	39	39
EDFE SPN	54	44	41	38	38	37
EDFE EPN	71	64	63	62	62	61
SP Distribution	44	44	43	43	42	41
SP Manweb	50	36	36	35	35	34
SSE Hydro	25	30	29	29	28	28
SSE Southern	49	54	54	53	52	51
Total	641	606	594	581	571	562

- 4.4 There was continuing restructuring at the majority of DNOs in 2004/05, most notably at Central Networks with the integration of the former Midlands and East Midlands companies. The financial impact of these restructurings accounts for around 4% of total operating costs.
- 4.5 This year has seen only a limited impact of payments to make up pension deficits. United Utilities made pension deficit payments in advance for the five years of DPCR4 on 31 March 2005. These are not reflected in their results for 2004/05 based on prior agreement with Ofgem that these costs will be treated as if they fall in DPCR4.

Capital Expenditure

4.6 Table 4.2 below shows total capital expenditure on new and replacement assets for year ended 31 March 2005 for each company compared to the forecast submitted during the DPCR4 process, using each company's own accounting definition of capex.

Table 4.2: Capital Expenditure compared to forecast

y/e 31 March 2005	Forecast (Sept 2004 update)	Actuals (RRP)	Variance to Forecast over/ (under)
£m (04/05 prices)			
CN West	102	99	(3)
CN East	85	95	10
UU	123	124	0
CE NEDL	61	61	(0)
CE YEDL	106	103	(3)
WPD S Wales	47	53	6
WPD S West	75	86	11
EDFE LPN	99	75	(25)
EDFE SPN	121	100	(20)
EDFE EPN	162	124	(38)
SP Distribution	85	106	21
SP Manweb	120	127	7
SSE Hydro	41	42	1
SSE Southern	118	110	(8)
Total	1,342	1,302	(40)

4.7 While the total capital expenditure for the industry was only 3% below the forecast, there were significant variances between actual costs and forecasts in some companies, notably the under-expenditure relative to forecast in the EDF Energy companies, and the over-expenditure relative to forecasts in SP and WPD.

4.8 The reasons for the differences include:

- ◆ connections customers deferring or not proceeding with large projects,
- ◆ re-phasing due to network outage constraints,
- ◆ problems associated with planning consents,

- ◆ reprioritising of some schemes; and
 - ◆ in some instances staff diverted to fault works and recruitment problems.
- 4.9 Most companies also showed a reduction in load related expenditure largely due to delays incurred in implementing major projects. Conversely, there was an increase in non-load related expenditure, which was largely due to higher capitalised fault costs. Some companies indicated that they had started to increase expenditure on asset replacement to reach the replacement rates planned for the DPCR4 period.
- 4.10 Resourcing difficulties were reported across the industry; several companies have increased recruitment activity, and some have initiated programmes to increase the availability of skilled resources in their region. Several companies also reported difficulties in obtaining access to the network to carry out work due to the risks involved in planning outages on heavily loaded sections of the network. Both of these issues, i.e. resource availability and access constraints, are likely to be ongoing challenges in the delivery of the increased capital expenditure planned during DPCR4.
- 4.11 The overall trend in new connections across the industry has been steady over the period but there has been increased emphasis on customer specific reinforcement. Load growth was steady overall, although some DNOs are experiencing a level of connections churn developing into “hot spots” near commercial centres. This has required reinforcement of existing bulk supply points and feeder circuits.
- 4.12 Risk assessment of overhead lines and substations is being carried out by DNOs to comply with Electricity Supply Quality and Continuity regulations (ESQCR). Remedial activities are underway and expected to lead to further costs in future.
- 4.13 Asset Risk Management practices have progressed over the year with several companies adopting a ‘health indices’ approach to quantification of asset condition and some companies are developing or adopting IT systems that assist with the optimisation of investment programmes.

- 4.14 Although the industry is developing improved asset management practices, most companies accept that further work is required to be able to quantify network risks and to develop investment cost/benefit analysis. The developments are essential to be able to prioritise investments and to make trade-off decisions.

Quality of service

- 4.15 There has been an increase in investment by the DNOs to improve the Quality of Service (QoS) and to meet the regulatory targets for Customer Interruptions (CI's) and Customer Minutes Lost (CMLs). A number of initiatives have been adopted including increased automation in both the urban and rural networks, under-grounding the worst performing overhead line circuits, refurbishment and use of ABC/BLX (covered) cables.
- 4.16 There has been widespread adoption of satellite navigation and completion of network vectorisation by most DNOs, which has significantly improved fault response and restoration times and helped to provide a better response to customer trouble call (i.e. fault reporting) service.
- 4.17 The industry is increasing efforts to improve network resilience to provide better performance during severe weather. Tree related faults have been identified by the Network Resilience Working Group as the main source of interruptions during severe weather and this is being addressed by an increased focus on tree cutting.

Summary RAV roll forward

- 4.18 Table 4.3 below shows Ofgem's current view of the RAV roll forward for the year ended 31 March 2005. The provisional RAV figures in the table have been discussed with the DNOs concerned, although in several cases the DNO has not agreed the figure shown. The RAV will be finalised at the next price review.

Table 4.3 RAV roll forward - Ofgem provisional view

	Balance b/f 1 April 2004	Memo: Additions per Final Proposals	Additions Actual	Deprecia- tion	less: Meters DRC	Balance as at 31 March 2005	Balance as at 31 March 2005 (see note)
	£m (2002/03)						£m (nominal)
CN West	976	90	82	(85)	(16)	957	1,027
CN East	978	79	77	(91)	(18)	946	1,015
UU	897	106	105	(63)	(21)	918	985
CE NEDL	596	59	56	(43)	(15)	593	637
CE YEDL	809	91	89	(80)	(16)	803	861
WPD S Wales	587	42	44	(44)	(13)	575	617
WPD S West	712	58	70	(59)	(15)	708	759
EDFE LPN	916	91	65	(80)	(19)	883	947
EDFE SPN	591	106	77	(41)	(15)	612	657
EDFE EPN	1,115	147	98	(96)	(27)	1,089	1,169
SP Distribution	1,314	49	70	(108)	(22)	1,254	1,346
SP Manweb	726	83	88	(60)	(15)	740	794
SSE Hydro	749	37	38	(50)	(9)	729	782
SSE Southern	1,371	109	99	(116)	(14)	1,340	1,438
Total	12,337	1,147	1,059	(1,015)	(234)	12,147	13,035

Note: the RAV balance at 31 March 2005 has been calculated using the RPI for March 2005.

- 4.19 The Depreciated Replacement Cost (“DRC”) of meters is deducted from 31 March 2005 RAV balance to carry forward since metering is now subject to a separate price control mechanism. Meters DRC in the table is the amount used in Final Proposals in establishing the DPCR4 allowance and has not been adjusted to reflect the actual expenditure in 2004/05.
- 4.20 Across the industry, actual RAV additions are 8% lower than the forecasts provided at the time of the price control. RAV additions are materially lower at EDF Energy’s DNOs but higher at Scottish Power and WPD.
- 4.21 In the Final Proposals Ofgem stated that in the event of actual 2004/05 RAV additions turning out to be materially different to the estimate used, Ofgem would reserve the right to claw back the benefits of any under-spend in 2004/05. To a significant extent, the rolling capex incentive applied in DPCR4 already removed the benefits of higher RAV additions in 2004/05. However, Ofgem will conduct further analysis and if any adjustments are needed to ensure companies do not benefit from over-forecasting 2004/05 values, these will be set

out in next year's report. Such adjustments (if any) are expected to be considerably smaller than the difference between forecast and actual additions.

Future RAV calculations

4.22 In calculating the RAV from 1 April 2005, Ofgem will apply the approach set out in Appendix 1 of the Final Proposals. In doing so, Ofgem will be primarily concerned with the substance of costs incurred rather than the form. For example:

- ◆ requiring additional categories of staff to complete timesheets will not make the associated costs eligible for direct inclusion in the RAV if they were not otherwise – neither will the costs of staff working on specific capital projects necessarily be included (even if timesheeted) unless they meet the definition in Final Proposals, including the requirement that the costs relate to staff physically performing work on the network;
- ◆ revenue earned by a related party fulfilling an obligation of the licensee and acting on behalf of the licensee will not count as external turnover in considering related party margins; and
- ◆ the costs and capital contributions associated with providing connections to the licensee's distribution system must be fully included in the data for the distribution business, whether provided by the licensee or a related party (in accordance with the definitions in the licence).

4.23 Ofgem will roll forward the RAV using the same basis for all licensees in accordance with the approach set out in appendix 1 of Final Proposals. In some cases it may be that a licensee has reported costs on a different basis in the past and those reported costs have been used by Ofgem. In such cases, Ofgem will nonetheless apply the common approach based on Appendix 1 of the Final Proposals going forward. Ofgem will be reluctant to re-open past RAV calculations but cannot rule this out, e.g. if it becomes evident that the information provided by the licensee concerned was inaccurate.

4.24 Ofgem will focus on the relevant boundaries in review meetings with the companies. Discussions of boundary issues with the companies are already

proving informative in understanding definitional difficulties and the possibilities for substitution. This will inform thinking on the categorisation of costs for incentive purposes at the next review.

Gearing to RAV

4.25 Table 4.4 below shows each DNO's gearing (defined as Net Debt to RAV), which is Ofgem's primary measure of gearing for the 2005-10 price review.

Table 4.4: Gearing to RAV as at 31 March 2005

	Net Debt as at 31 March 2005	RAV as at 31 March 2005 (after removal of Meters DRC)	Gearing %
£m (nominal)			
CN West	472	1,027	46%
CN East	262	1,015	26%
UU	691	985	70%
CE NEDL	266	637	42%
CE YEDL	396	861	46%
WPD S Wales	146	617	24%
WPD S West	257	759	34%
EDFE LPN	490	947	52%
EDFE SPN	470	657	72%
EDFE EPN	726	1,169	62%
SP Distribution	779	1,346	58%
SP Manweb	180	794	23%
SSE Hydro	475	782	61%
SSE Southern	890	1,438	62%
TOTAL	6,501	13,035	50%

4.26 The gearing ratio used in the DPCR4 cost of capital was 57.5% compared to the overall industry weighted average gearing of 50%. DNO's individual debt and gearing varies dependent on the company's own financing structures within individual ownership groups. The apparent low level of debt in some DNOs can be attributed to funding by debt in unregulated businesses and dividends from the DNOs being used to fund interest payments. The table does not include guarantees provided by licensees for parent company debt, which amount to £2,089m jointly by SP Distribution and SP Manweb (along with SP Transmission) and £450m by SSE Hydro.

5. DNO Summaries

5.1 This section shows the performance of each of the DNOs using data provided by them with no adjustment by Ofgem. It includes the following data:

- ◆ 2003/04 and 2004/05 actual operating costs and capital expenditure;
- ◆ 2004/05 forecast operating costs and capital expenditure taken from the forecasts provided to Ofgem during DPCR4; and
- ◆ the DNO's own commentary explaining the trend and movements in the data.

5.2 The costs quoted by different companies are not necessarily directly comparable as they may include atypical costs and the application of differing but equally valid accounting practices (e.g. some are on a fully absorbed basis and others not) that can distort comparisons. Caution should therefore be exercised, as it could be inappropriate to directly compare quoted costs. The data in other chapters have been adjusted by Ofgem and therefore may vary from those in the following tables.

5.3 Ofgem has not verified or edited the commentary provided by the DNOs and accepts no responsibility for its accuracy or completeness. Any questions on the commentaries should be addressed to the relevant company.

Central Networks West plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	103.2	90.7	95.4
<i>Memo: Fault costs expensed</i>	21.5	31.9	13.9
Capital Expenditure			
- Net Load related new assets & reinforcement	24.0	13.5	21.0
- Non-load non-fault new & replacement assets	67.3	68.3	66.5
- Fault replacement	17.6	16.9	14.1
- Non-operational new & replacement assets	-	-	-
Total Capital Expenditure	108.9	98.7	101.6

Integration with Central Networks East plc

The E.ON Group took full operational control of the Midlands Electricity business (Distribution, Contracting, Metering and Generation Assets) on 16 January 2004. As a result, during the year, Central Networks West plc (CNW) (the former distribution business of Midlands Electricity) has been working closely with Central Networks East plc (CNE) on an integration programme across various operational and support functions. Please refer to the section on CNE for details of the integration programme.

The legacy CNW systems were archived on 31 December 2004 and all data migrated to the CNE system (SAP) with effect from 1 January 2005. The data migration process was a critical and time-consuming exercise, but was completed successfully through utilisation of in-house and external expertise. CNW now utilises SAP for the management of its financial and operational processes.

The total costs of the full integration programme, including severance, pensionable Earnings Related Deficiency Contributions (ERDCs) and restructuring are expected to be approximately £83m across the whole E.ON UK Group, of which £1.3m has been incurred directly by CNW during the year. The majority of the remaining costs have been charged to other entities within the E.ON UK Group, including the previous external service provider, Central Networks Services Limited.

Although the CNW and CNE businesses are managed centrally from an operational point of view, they will continue to be accounted for separately for regulatory purposes.

Operating costs

Total operating costs fell by £12.5m (12.1%) compared to 2003/04. The improvement in operating costs was principally due to:

- ◆ some merger efficiencies following the integration with CNE (the full-year impact of merger efficiencies will be experienced in future years). Many of the redundancies and system rationalisation programmes have taken place across the Midlands Group, which has meant that many of the efficiency savings have ultimately fallen within this business as opposed to CNE, and
- ◆ further, temporary, cost reductions have arisen from a fall in professional services expenses as a result of reduced activity in business and IT process improvements due to the focus on integrating the business during 2004/05.

These reductions have been partially offset by increased staff and premises cost inflation, increased insurance premiums and wayleave payments as pressure from external sources continues to mount.

The acquisition of the Midlands Electricity business by the E.ON Group and its impact on CNW was not anticipated in 2003 when the 2004/05 forecast was produced on a standalone basis.

The approach to Network repair and maintenance was essentially the same in the current and the prior year. Loss of supplies under storm conditions in 2002, which materially affected customers, continues to drive higher tree cutting activity, either proactively through increased frequency of cut, or reactively following an increased awareness from customers on a local level.

The variance in fault costs expensed between the years and to forecast is principally due to different allocations of indirect costs across revenue activities, driven by the current regulatory reporting template (i.e. opex). However, this does not result in any change in allocation between capex and opex.

CNW has been working closely with Ofgem and other Distribution Network Operators (DNOs) to improve the comparability of cost information between companies. This programme is at the start rather than the end of its process.

Capital expenditure

During the year, CNW has seen a decrease in New Connections activity that has resulted in expenditure below forecast. However, general loads continue to increase and expenditure to reinforce the network exceeded both the 2003/04 expenditure and the 2004/05 forecast. This expenditure will ensure that the network can accommodate increasing loads and avoid losses of supply following faults on the EHV networks.

The need to replace assets, first installed in the 1950's and 1960's, continues to rise and this is reflected in a non-load related expenditure that exceeded both the 2003/04 expenditure and the 2004/05 forecast. In particular, over £15m was spent on replacing and refurbishing 11kV overhead lines, helping to improve the reliability of supplies to rural communities. This is in line with the strategy to remove the majority of 'small section' overhead line, which is known to be vulnerable under storm conditions, from the CNW network by 2010. CNW is anticipating a significant increase in capital expenditure during DR4 as the capital investment programme is accelerated in order to smoothly and efficiently leverage the resources required to address the growing needs of the network and avoid the inefficiencies of a stop-go approach to the work programme experienced over the DR3-DR4 transition.

Underground cables are generally extremely reliable but occasionally 'rogue' low voltage circuits are identified that have suffered a series of faults in a relatively short period of time. In these instances the entire circuit is replaced to ensure that the problem is eliminated, and almost £3m was spent in 2004/05 on this activity.

In addition, almost £19m was spent on replacing equipment in substations throughout the region to ensure that the current high level of reliability of electricity supplies will be maintained in the future. The investment was made on a range of projects from a major scheme to replace 132kV switchgear at Gloucester to replacement of oil filled switchgear at local 11kV substations.

As well as replacing assets to reduce the number of faults that occur, almost £5m was spent installing additional equipment to reduce the effect of faults that occur and speed up restoration of supplies.

CNW continues to improve quality of supply for its customers. During 2004/05 it outperformed Customer Interruptions (CI) and Customer Minutes Lost (CML) targets by 17% and 23%

respectively. This also represents a significant improvement over the previous year, particularly CMLs, which were reduced by over 17 minutes. The adoption of enhanced operational response techniques was reflected in the improvement in average fault duration (CML/CI), which reduced from 92 minutes in 2003/04 to 82 minutes in 2004/05.

There was no non-operational spend in 2004/05 due to the integration of the two businesses, CNW and CNE. A number of IT led initiatives were implemented specifically to rationalise systems and processes following the merger but a level of ongoing spend will need to be reinstated in future years.

Central Networks East plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	92.5	91.4	93.9
<i>Memo: Fault costs expensed</i>	24.6	28.3	27.0
Capital Expenditure			
- Net Load related new assets & reinforcement	26.5	29.8	35.7
- Non-load non-fault new & replacement assets	52.2	53.7	41.5
- Fault replacement	6.2	11.1	7.8
- Non-operational new & replacement assets	2.0	0.6	2.4
Total Capital Expenditure	86.9	95.2	87.4

Integration with Central Networks West plc

The E.ON Group took full operational control of the Midlands Electricity business (Distribution, Contracting, Metering and Generation Assets) on 16 January 2004. As a result, during the year, Central Networks East plc (CNE) has been working closely with Central Networks West plc (CNW) (the former distribution business of Midlands Electricity) on an integration programme across various operational and support functions.

The key integration challenges and achievements included development of a centrally managed, locally delivered, business model; rationalisation of locations (Head Offices, Field Operating Centres and Logistics Centres); 700 job reductions; 25 IS projects undertaken to rationalise systems; commonality of Procurement, Fleet and Logistics processes; archiving of the CNW legacy systems and migration onto the CNE system (SAP); standardisation of policies and processes; and the creation of the Central Networks identity. During the year, we have spent a significant amount to increase the awareness and understanding of Central Networks.

The integration programme has meant that it has been a challenging year for both CNE and CNW and it has proved demanding managing the restructuring of the business whilst maintaining business as usual processes. However, the success of the integration challenges described above, highlight the ongoing time and effort being devoted by managers and employees to ensure a successful outcome to all initiatives.

The total costs of the full integration programme, including severance, pensionable Earnings Related Deficiency Contributions (ERDCs) and restructuring are expected to be approximately £83m across the whole E.ON UK Group, of which £6.8m has been charged directly to CNE during the year. The majority of the remaining costs have been charged to other entities within the E.ON UK Group.

Although the CNE and CNW businesses are managed centrally from an operational point of view, they will continue to be accounted for separately for regulatory purposes.

Operating costs

Total operating costs of CNE fell by £1.1m (1.2%) compared to the prior-year. This reduction principally relates to:

- ◆ a fall in meter recertification costs (one-off impact),

- ◆ lower levels of change in the areas of business and IT process improvements as the focus in 2004/05 was on integration, and
- ◆ some merger efficiencies following the integration with CNW (the full-year impact of merger efficiencies will be experienced in future years).

These reductions were primarily offset by £6.8m of restructuring costs, salary inflation, increased costs arising from creating a community awareness of Central Networks and increased pressure on wayleave compensation payments.

The acquisition of the Midlands Electricity business and its impact on CNE was not anticipated in 2003 when the 2004/05 forecast was produced on a standalone basis.

The approach to Network repair and maintenance was essentially the same for both the current and the prior year. There was more investment in tree cutting in 2004/05 following centralisation of control which allowed a thorough review of needs to be performed. The increased spend related particularly to reactive (customer driven) work, coupled with higher costs due to an increase in the level of planned outages.

Like CNW, CNE has also been working closely with Ofgem and other Distribution Network Operators (DNOs) to improve the comparability of cost information between companies. This programme is at the start rather than the end of its process.

Capital expenditure

During the year, CNE spent £29.8m (after deducting customer contributions and stating on a fully absorbed cost basis) providing new customer connections and reinforcing the network to ensure that future increases in load can be accommodated. Of this total, £14m was spent on providing new connections which is a significant increase compared both to the actual expenditure in 2003/04 and the forecast for 2004/05, and includes almost £9m expenditure on major schemes.

The need to replace assets, first installed in the 1950's and 1960's, continues to rise and this is reflected in a non-load related expenditure that exceeded the 2004/05 forecast. In particular, almost £12m was spent on replacing equipment in substations throughout the region to ensure that the current level of reliability of electricity supplies will be maintained in the future. CNE is anticipating a significant increase in capital expenditure during DR4 as the capital investment programme is accelerated in order to smoothly and efficiently leverage the resources required to address the growing needs of the network and avoid the inefficiencies of a stop-go approach to the work programme experienced over the DR3-DR4 transition.

Additional expenditure was also incurred on measures to improve the safety of the network with over £3m being spent principally on replacing 11kV overhead switchgear, and addressing safety issues associated with LV overhead lines.

As well as replacing assets to reduce the number of faults that occur, almost £5m was spent installing additional equipment to reduce the effect of faults that occur and speed up restoration of supplies.

CNE continues to improve quality of supply for its customers. During 2004/05 there were significant reductions in both Customer Interruptions (CI), which were reduced by over 13%, and Customer Minutes Lost (CML), which were improved by over 15 minutes from the previous year. The adoption of enhanced operational response techniques was reflected in the improvement in average fault duration (CML/CI), which reduced from 104 minutes in 2003/04 to 100 minutes in 2004/05.

The level of non-operational capex was down on the prior-year and the 2004/05 forecast due principally to a reduction in IT spend as the focus was on the integration of CNE and CNW and

alignment of systems and operating platforms. This level of spend will need to be reinstated in future years.

United Utilities Electricity plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	48.4	73.0	83.2
<i>Memo: Fault costs expensed</i>	<i>15.0</i>	<i>12.1</i>	<i>13.5</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	19.1	17.4	27.6
- Non-load non-fault new & replacement assets	80.8	80.4	72.2
- Fault replacement	21.2	25.8	23.6
- Non-operational new & replacement assets	12.6	13.8	7.7
Total Capital Expenditure	133.7	137.4	131.1

United Utilities Electricity PLC manages a 58,000 km distribution network, which delivers electricity to more than 2.3 million customer premises in north west England. We also have a contract with United Utilities Networks Limited to provide connections and metering services to domestic, commercial and industrial developers.

Operating costs

The increase in operating costs reflects the existence of a number of one-off costs and new reporting requirements within the 2004/05 accounts.

In January 2005, an exceptional storm severely damaged the electricity network and disrupted supplies to 250,000 customers in Cumbria and Lancashire. The additional impact on operating costs in 2004/05 of restoring customer supplies and rectifying the damage was £2.3m.

There have been two other significant changes in the operating cost base of the company between 2003/04 and 2004/05, pensions and restructuring costs.

Pension costs have increased principally as a result of increasing deficits in the pension schemes. An additional £18m has been included in the profit & loss account compared to 2003/04.

During 2004/05, the company implemented a major restructuring exercise to improve operating efficiency. The one-off restructuring costs incurred in 2004/05 totalled £8.7m. The company has created an organisation that is focussed on ensuring efficient processes, high performing teams and placing continued emphasis on customer service.

During 2004/05 the overall performance of the network was good with electricity supplies available for 99.99 per cent of the time. All the overall standards of performance set by the regulator were achieved. Excluding the exceptional storm in January, the number and duration of customer interruptions was at the lowest level since privatisation.

Capital expenditure

£137.4 million was invested during 2004/05, the year of highest investment during the 2000-2005 price control period.

Investment included the completion of a number of network reinforcement projects at Lancaster, Carlisle and Westhoughton. Some of the planned projects for 2004/05 have been deferred,

contributing to load-related costs being lower than forecast. Investment in these projects will be incurred in future years.

Volumes of new connections to our network in 2004/05 were lower than predicted. New connections investment is dictated by customer demand. 2004/05 saw reduced activity in the market for new connections, mainly due to lower activity in the domestic housing market.

We have continued to make significant investment to improve network performance and the service experienced by customers and to maintain the safety of our assets. This expenditure is larger than forecast due to increases in unit costs, the acceleration of projects relating to pilot networks and increased scope of HV overhead line work.

The storm in January has resulted in our fault replacement costs being higher than forecast. Once the atypical costs associated with the storm (£3.2m) are taken into account, it can be seen that 2004/05 costs remain broadly in line with forecasts.

We have continued to invest significantly in IT systems during 2004/05. These systems will contribute to better customer service and will also support project and programme management and work management. This investment in non-operational assets is higher than 2003/04, and higher than forecast, due to increased commitment to projects providing DUoS billing and support services and improved work management capability.

Readers should recognise that the costs quoted by different companies will not always be directly comparable. For example, the costs quoted for United Utilities Electricity include a number of atypical costs that can distort comparisons with other DNOs. Additionally, different accounting practices followed by companies will result in it being inappropriate to directly compare quoted costs.

Northern Electric Distribution Limited

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	59.7	56.2	56.2
<i>Memo: Fault costs expensed</i>	2.1	2.8	2.3
Capital Expenditure (Excludes meters)			
- Net Load related new assets & reinforcement	7.2	13.9	12.3
- Non-load non-fault new & replacement assets	42.5	30.9	37.7
- Fault replacement	8.3	15.7	10.7
- Non-operational new & replacement assets	2.4	2.5	4.4
Total Capital Expenditure	60.4	63.0	65.2

Operating costs

Our performance in 2004/05 is in line with forecast and £3.5m below the prior year actual. The predicted reductions were delivered in accordance with forecast.

Year on year variance

Operating costs were £3.5m below prior year. Predicted reductions of £1.8m on Rates due to transitional relief and £1.9m in the levels of de-minimis activity were secured. Efficiency savings in areas such as maintenance absorbed inflationary pressures and an increase in atypical costs.

Variance to forecast

Operating costs were in line with forecast. Atypical costs of £2.3m were absorbed by a reduction in projected Rates of £0.8m, £0.6m lower de-minimis activities and lower contract costs on a significant contract together with taking opportunities to reduce maintenance costs.

Capital expenditure

Our performance in 2004/05 reflects the execution of our plan based on our FBPQ submission. On all our major output tracking measures we have had an excellent year, with the distribution system continuing to meet the capacity and connections obligations placed on it.

In terms of the physical deliverables achieved, we have:-

- ◆ Replaced and refurbished 273km of overhead lines;
- ◆ Replaced 434km of LV, HV and EHV cables;
- ◆ Replaced over 31 items of EHV plant;
- ◆ Invested in the first phase of capacity increase to the Scarborough area; and
- ◆ Increased capacity to facilitate a connection for the MOD at Menwith Hill radar station.

Turning to financial performance, there have been a number of minor variations which are well within the normal churn in a long run plan. Taking each in turn:-

Variance to forecast

Load related expenditure

Net load related capex in NEDL is up against FBPQ by 13% or £1.6m. This is driven by variations in DNO reinforcement. The variations (positive and negative) were due to design uncertainties on eleven major schemes.

Non-load related expenditure

The main reason for expenditure being £6.8m below our forecast is the delay of six major schemes following the adoption of a strategy involving a detailed assessment of EHV overhead line schemes. In addition, there were variations on 10 major substation schemes, 3 of which were re-phased in the plan. This was partially offset by increased expenditure on enhanced requirements on fluid filled cable replacements.

Fault related expenditure

The increase in fault costs was mainly driven by volume increases caused by the storms in January 2005. In addition, the change in the allocation of indirect costs accounts for £1.7m.

Non operational capex

Non operational expenditure was below the FBPO forecast by £1.9m in 2004/05. This was due to minor underspend on Telecomms, furniture fittings and office equipment, along with a more significant underspend on IT capex of £1.7m which was due to the phasing of expenditure on two major schemes, both were delayed until 2005/06.

Year on year variance

Overall, 2004/05 expenditure was £2.6m up on 2003/04. This represents an increase in fault costs; the storms of January 2005 being the main contributor to this variance.

Yorkshire Electricity Distribution plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	69.2	70.9	75.3
<i>Memo: Fault costs expensed</i>	3.8	3.9	3.6
Capital Expenditure (Excludes meters)			
- Net Load related new assets & reinforcement	23.4	20.0	24.2
- Non-load non-fault new & replacement assets	39.1	60.3	60.7
- Fault replacement	19.8	22.5	20.6
- Non-operational new & replacement assets	0.0	0.1	0.0
Total Capital Expenditure	82.3	102.9	105.4

Operating costs

Our performance in 2004/05 compares favourably against forecast and is in line with an inflationary increase on the actual for 2003/04.

Year on year variance

After allowing for inflationary pressures, our 2004/05 performance is in line with the prior year at a headline level. Efficiency savings in the areas such as metering and IT have been re-invested in customer service and safety training and improvement programs.

Variance to forecast

At the time our forecast was provided, two significant contracts were being negotiated; projections were made based on existing contracts and volumes. We were successful in negotiating better terms and reducing volumes, which were £3.6m below projections. The level of claims costs were below projected levels and we were also able to make opportunities to reduce maintenance costs.

Capital expenditure

Our performance in 2004/05 reflects the execution of our plan that has involved significant acceleration from investment levels of the past. As forecast in our FBPQ we anticipate the levels of expenditure to continue increasing over the remainder of this review period. On all our major output tracking measures we have had an excellent year, with the distribution system continuing to meet the capacity and connections obligations placed on it.

In terms of the physical deliverables achieved, we have:-

- ◆ Replaced and refurbished 281km of overhead lines;
- ◆ Replaced 1012km of LV, HV and EHV cables;
- ◆ Replaced over 96 items of EHV plant;
- ◆ Carried out deep reinforcement work to facilitate a new float glass plant;
- ◆ Carried out system reinforcement for load growth in the Leeds area; and
- ◆ Facilitated the connection of 6 small generation schemes for the Waste Recycling Group.

Turning to financial performance, there have been a number of minor variations which are well within the normal churn in a long run plan. Taking each in turn:-

Variance to forecast

Load related expenditure

Net load related expenditure was £4.2m (17%) below FBPO forecast. This was driven by a reduction in DNO reinforcement as a result of design uncertainties (positive and negative) on twenty five major schemes, variations to 9 projects associated with customers and build uncertainties affected 10 projects. In terms of major reinforcement schemes, which are obviously subject to more planning uncertainty, we have seen a number of schemes cancelled due to customers delaying or withdrawing.

Non-load related expenditure

We have spent £0.4m less than we forecast. This is because:

- ◆ An enhanced fluid filled cable replacement programme was funded.
- ◆ There was an increase in the scope of 132kV schemes following detailed pre-project inspections.
- ◆ There was a reduction in substation schemes, mainly driven by the re-phasing of 8 major substation replacement projects 3 of which were delayed due to land permission issues, 3 were delayed to co-ordinate with other projects or system outages and 2 were re-phased and are currently in construction.
- ◆ Resilience expenditure is flood defence costs and was included in substations in the FBPO.

Fault replacement expenditure

The variance reflects an increase in our customer service focus on street lighting faults at the request of the Street lighting authorities and the impact of the January 2005 storms.

Year on year variance

Overall, we are pleased to report that 2004/05 expenditure is £20.6m up on 2003/04. This mainly represents acceleration in investment on overhead lines, operational IT and switchgear focussed health & safety expenditure. The variance also includes the increase in street lighting faults and the impact of the January 2005 storms as mentioned above.

Western Power Distribution (South Wales) plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	50.1	45.4	48.2
<i>Memo: Fault costs expensed</i>	<i>1.2</i>	<i>1.6</i>	<i>1.7</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	13.0	13.7	12.4
- Non-load non-fault new & replacement assets	29.5	31.1	27.6
- Fault replacement	7.6	7.7	6.8
- Non-operational new & replacement assets	1.5	1.4	4.7
Total Capital Expenditure	51.6	53.9	51.5

Operating Costs

Several factors have contributed to the overall £4.7m decrease in actual operating costs between 2003/04 and 2004/05. The major factors are:

- ◆ Cost reductions of £6.4m due to favourable provision movements and an increase in proportion of corporate overheads capitalised to reflect the actual balance between operational capital expenditure and network operating costs;
- ◆ Restructuring costs (£1.5m increase) associated with the centralisation of both Control Centre and Wayleaves Administration;
- ◆ Other cost increases totalling £1.4m due to salaries pay award, network rates and pensions;
- ◆ Cost reductions totalling £1.2m associated with network operating costs. This reduction is driven by the tailing of the programme to clear the tree cutting backlog.

The major factor that accounts for the £2.8m difference between the 2004/05 actual and the 2004/05 forecast provided in December 2003 for the Distribution Price Control Review (DPCR) is that the anticipated costs arising from the inspection requirements associated with the ESQC Regulations were included in the DPCR forecast. This issue is yet to be resolved with the Department of Trade and Industry.

Capital Expenditure

Total Capital Expenditure for 2004/05 is higher than the forecast provided in December 2003 for the Distribution Price Control Review (DPCR). A significant proportion of this variation relates to increased costs associated with pension deficits.

'Net Load related new assets & reinforcement' expenditure has been higher than the DPCR forecast. Increased economic activity, as measured by the increase in the number of new housing connections and the level of regional GDP for South Wales has driven the increase in expenditure associated with load related new assets provided for new connections. Externally driven delays in obtaining of third party consents associated with a few higher voltage distribution system reinforcement schemes have resulted in lower reinforcement expenditure. Expenditure associated with the provision of connections to distributed generators has been lower than forecast.

'Non-load non-fault new & replacement assets' expenditure has been higher than the DPCR forecast. The lower number of higher voltage transformer changes required has resulted in lower replacement expenditure than forecast. Total payments associated with injurious affection claims have seen a significant increase above the level forecasted. Quality of supply initiatives has continued to be a main focus, and consequently expenditure in this area has therefore been higher than forecast.

'Fault Replacement' expenditure is reactive to need and was higher than forecast.

'Non-operational new & replacement assets' expenditure was lower than forecast due to the deferment of the desktop PC and server refresh programme.

Western Power Distribution (South West) plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	52.2	57.6	60.2
<i>Memo: Fault costs expensed</i>	<i>2.0</i>	<i>3.1</i>	<i>2.1</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	17.5	21.5	17.0
- Non-load non-fault new & replacement assets	45.8	46.8	42.0
- Fault replacement	15.6	17.4	16.2
- Non-operational new & replacement assets	9.1	6.0	9.5
Total Capital Expenditure	88.0	91.7	84.7

Operating Costs

Several factors have contributed to the overall £5.4m increase in actual operating costs between 2003/04 and 2004/05. These factors are:

- ◆ Cost increases totalling £4.9m due to salaries pay award, network rates and the impact of the ESPS pension deficit;
- ◆ Cost reductions of £4.5m due to favourable provision movements and an increase in the proportion of corporate overheads capitalised to reflect the actual balance between operational capital expenditure and network operating costs;
- ◆ Restructuring costs (£3.5m increase) associated with the centralisation of both Control Centre and Wayleaves Administration;
- ◆ Cost increases totalling £1.5m associated with network operating costs. This increase has resulted from increased activity associated with tree cutting and overhead line inspection and more extensive use of mobile generation when undertaking maintenance.

The major factor that accounts for the £2.6m difference between the 2004/05 actual and the 2004/05 forecast provided in December 2003 for the Distribution Price Control Review (DPCR) is that the anticipated costs arising from the inspection requirements associated with the ESQC Regulations were included in the DPCR forecast. This issue is yet to be resolved with the Department of Trade and Industry.

Capital Expenditure

Total Capital Expenditure for 2004/05 is higher than the forecast provided in December 2003 for the Distribution Price Control Review (DPCR). A significant proportion of this variation relates to increased costs associated with pension deficits.

'Net Load related new assets & reinforcement' expenditure has been higher than the DPCR forecast. Increased economic activity, as measured by the increase in the number of new housing connections, has driven the majority of the increase in expenditure associated with load related new assets provided for new connections. Although GDP for the South West region was in line with the forecast, commercial connection activity in the region has been higher than that forecast. Delays experienced on a major extra high voltage distribution system scheme in mid-Devon resulted in lower expenditure on reinforcement. Expenditure associated with the provision of connections to distributed generators has been lower than forecast.

'Non-load non-fault new & replacement assets' expenditure has been higher than the DPCR forecast. Higher levels of replacement activity across all asset types resulted in expenditure higher than forecast, although more significant increases were associated with extra high voltage overhead lines, low voltage cables, and service cables & lines. Total payments associated with injurious affection claims have seen an increase above the level forecast. Quality of supply initiatives has continued to be a main focus, and consequently expenditure in this area has therefore been higher than forecast

'Fault Replacement' expenditure is reactive to need and consequently was higher than the forecast, reflecting the two storm events and Boscastle incident that occurred during 2004/05.

'Non-operational new & replacement assets' expenditure was lower than forecast. This was due to the deferment of desktop PC and server refresh programme and a change in the timing of vehicle purchases.

EDF Energy Networks (EPN) plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	121.2	114.4	121.3
<i>Memo: Fault costs expensed</i>	<i>13.9</i>	<i>18.5</i>	<i>22.4</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	27.5	24.5	49.8
- Non-load non-fault new & replacement assets	69.2	75.0	91.8
- Fault replacement	20.8	24.6	20.2
- Non-operational new & replacement assets			8.0
Total Capital Expenditure	117.5	124.1	169.8

Operating expenditure

Overall 2004/05 was a year of consolidation for EDF Energy following the acquisition of SEEBOARD Group plc in 2002 and the subsequent business restructuring and integration programmes in 2003. For this reason, and also because of the focus on the distribution price control review, there were no major cost reduction programmes in 2004/05. Operating costs for 2004/05 were broadly consistent with 2003/04 after allowing for movements in atypical items.

Expenditure on tree cutting increased by £5m as a result of a comprehensive review and action plan following the October 2002 storm. The action plan included the clearance of all 132kV and EHV overhead line circuits, an accelerated program for HV feeders, additional investment in ABC (covered conductor) on LV overhead lines close to trees, and a proactive cutting programme for LV circuits. The tree cutting programme is delivering significant quality of supply and storm resilience benefits to EPN's customers.

Capital expenditure

Expenditure on net load related new assets and reinforcement and non-load non-fault new and replacement assets were below forecast for a range of reasons. In particular, connections work was significantly below forecast as a result of customers deferring or not proceeding with large projects.

Other reasons for the under spend include re-phasing due to network outage constraints (e.g. Burwell SGT and switchgear), alternate load transfer schemes (e.g. Tilbury Grid), additional time taken to agree schemes with NGC (e.g. Mill Hill reinforcement), and problems associated with legal/planning consents (e.g. Horningsea overhead line). In addition some schemes have been reprioritised/re-evaluated following the outcome of detailed feasibility studies or detailed design work.

Quality of Supply

In 2004/05 EPN outperformed both of its quality of supply targets (the number of customer interruptions and the associated number of customer minutes lost). This improved performance has principally been achieved by increased investment in automation on the high voltage (HV) network. In 2004/05 EPN automated 1700 HV circuits. This represents 50% of EPN's total number of HV circuits. The investment in both automation and tree cutting has also delivered significant improvements in severe weather performance. During the severe weather event of

October 2002 around 60% of affected customers were restored in three hours. In comparison during the severe weather events of 2004/05 some 90% of customers were restored within three hours.

Fault expenditure

Fault costs as whole slightly above forecast. The overspend against the forecast capital spend is due to differing assumptions relating to fault capitalisation rates.

EDF Energy Networks (LPN) plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	86.3	88.7	84.4
<i>Memo: Fault costs expensed</i>	<i>11.0</i>	<i>13.0</i>	<i>15.9</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	14.9	9.9	24.6
- Non-load non-fault new & replacement assets	56.6	50.1	64.1
- Fault replacement	10.4	14.7	10.6
- Non-operational new & replacement assets	-	-	4.9
Total Capital Expenditure	81.9	74.7	104.2

Operating expenditure

Overall 2004/05 was a year of consolidation for EDF Energy following the acquisition of SEEBOARD Group plc in 2002 and the subsequent business restructuring and integration programmes in 2003. For this reason, and also because of the focus on the distribution price control review, there were no major cost reduction programmes in 2004/05.

The overall increase in operating costs reflects a number of factors. In particular, the cost of Network Rates increased by £1.8m, and also wayleave and related costs increased by £0.5m.

There was a reduced contribution to pension deficit costs compared to 2003/04. However, this reduction was offset by increased costs of metering and information technology related activities.

Capital expenditure

Expenditure on net load related new assets and reinforcement is below forecast primarily as a result of lower than expected levels of connections work as a result of customer action (i.e. not proceeding with or deferring projects). Expenditure on non-customer related reinforcement was in line with forecast.

Expenditure on non-load non-fault new and replacement assets was below forecast after adjusting for an error in the forecast relating to street-lighting faults. Reasons for underspend primarily relate to contract delays (e.g. Wandsworth – Norroy gas cable replacement), and projects with NRSWA related costs not proceeding.

Quality of Supply

In 2004/05 LPN substantially outperformed its customer minutes lost target but marginally underperformed on customer interruptions. However, during the recent distribution price control review LPN was recognised as a frontier performer with respect to customer interruptions performance. As a consequence even though LPN did not achieve its target it received a reward based on the level of interruptions improvement achieved since 2001/02. LPN's improved performance has principally been achieved by increased investment in automation on its high voltage (HV) network. In 2004/05 LPN automated 950 HV circuits. This represents approximately 50% of LPN's total number of HV circuits.

Fault expenditure

Fault costs as whole were slightly above forecast. The overspend against the forecast capital spend is due to differing assumptions relating to fault capitalisation rates.

EDF Energy Networks (SPN) plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	80.2	80.2	86.4
<i>Memo: Fault costs expensed</i>	9.2	16.9	10.6
Capital Expenditure			
- Net Load related new assets & reinforcement	16.3	17.70	23.7
- Non-load non-fault new & replacement assets	55.3	62.3	84.3
- Fault replacement	16.2	20.2	12.5
- Non-operational new & replacement assets	0.7		8.8
Total Capital Expenditure	88.5	100.2	129.3

Operating expenditure

Overall 2004/05 was a year of consolidation for EDF Energy following the acquisition of SEEBOARD Group plc in 2002 and the subsequent business restructuring and integration programmes in 2003. For this reason, and also because of the focus on the distribution price control review, there were no major cost reduction programmes in 2004/05.

Tree cutting costs increased by £1.5m as a result of a comprehensive review and action plan following the October 2002 storm. The SPN area has a particularly high level of tree affected overhead networks – nearly 50%.

A charge for uninsured losses of £1.2m was incurred in respect of events not previously provided for. Combined premises/corporate charges increased by £1.0m, insurance costs by £1.0m. Other cost increases include the effects of reduced overhead capitalisation.

Capital expenditure

Expenditure on net load related new assets was broadly in line with forecast. Expenditure on non-load non-fault new and replacement assets and reinforcement was below forecast for a range of reasons. In particular, delays associated with legal consents and outage issues, reassessment of quality of supply expenditure based on actual performance, and projects reassessed and re-phased. In addition £3.4m of the variance is due to street lighting and underground cable service faults being included in the forecast in error.

Quality of supply

In 2004/05 SPN outperformed against both of its quality of supply targets. This improvement has been achieved as a result of investment in overhead line refurbishment, improved restoration performance and automation of 33kV open ring circuits. SPN has challenging targets for the next price control period which commenced 1 April 2005. In order to achieve these targets automation will be applied to the high voltage network building on the experience gained in both EPN and LPN.

SP Distribution Ltd

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	66.4	66.4	67.4
<i>Memo: Fault costs expensed</i>	6.8	9.7	5.3
Capital Expenditure			
- Net Load related new assets & reinforcement	27.7	21.9	35.6
- Non-load non-fault new & replacement assets	65.2	51.1	32.6
- Fault replacement	25.9	33.0	16.4
- Non-operational new & replacement assets			
Total Capital Expenditure	118.8	106.0	84.6

Operating costs

Compared to 2003/04 operating costs in 2004/05 reduced in real terms although nominally appeared constant. The reduction is mainly attributable to a decrease in Inspection and Maintenance costs arising from the introduction of efficiencies and a reduction in activity relating to link boxes and pillars. This was partly offset by an increase in the level of activity associated with system faults and increased costs of bought in services. Other reductions arose in bad debts, insurance and professional services. The cost of network rates, property and IT costs increased which also partly offset the savings.

Actual costs incurred were less than forecast due to reduction in the anticipated costs of insurance, professional fees and bad debts and other costs with higher than anticipated increases in the costs of network rates, IT and property costs.

Capital expenditure

LOAD RELATED

A combination of economic factors, which determine the level of connections activity, and the penetration of competitive connections, which has impacted the timing of expenditure, are the major cost drivers for load related expenditure. The volume of licensed new connections has fallen compared to forecast. The number of adopted connections has increased more than was originally forecast. It is for these reasons the actual expenditure in 2004/05 was below the forecast level for that year.

Expenditure in 2004/05 was below the level incurred in 2003/04 due to changes in the level of activity and the penetration of competitive connections.

NON LOAD NON FAULT

The actual expenditure is higher than forecast due to the need to re-profile delivery of a number of projects because of outage constraints and asset condition information. A number of site-specific issues increased costs on several projects. In addition, there was a renewed focus on the replacement of poorly performing HV cable sections.

There was reduced expenditure in 2004/05 associated with new overhead lines due to extension in the time required to obtain permissions. A major overhead line and substation modernisation project in the Scottish Borders was completed during 2003/04. As a result, actual expenditure in 2004/05 was below the level incurred in 2003/04.

FAULT REPLACEMENT

During the price control period ending 2004/05, the business made a strategic decision to make the transition from a regional to a functional business structure. This resulted in the implementation of a dedicated fault restoration and repair business function. In support of this, numerous fault restoration and repair teams have been established on a shift pattern basis and the costs incurred during 2004/05 reflect this transition. These costs were not reflected in the forecast although it is expected that this approach will deliver cost benefits in future years.

Expenditure on fault replacement was higher in 2004/05 when compared to 2003/04 due to an increase in the number and complexity of faults, which arose during 2004/05.

SP Manweb plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	59.4	65.6	63.9
<i>Memo: Fault costs expensed</i>	5.9	13.4	7.1
Capital Expenditure			
- Net Load related new assets & reinforcement	30.7	33.9	53.8
- Non-load non-fault new & replacement assets	53.7	62.3	49.2
- Fault replacement	26.9	30.9	17.1
- Non-operational new & replacement assets			
Total Capital Expenditure	111.3	127.1	120.1

Operating costs

Compared to 2003/04 operating costs increased by £6.2m. The major areas of increase related to network costs associated with urgent repairs that were required to deal with defects and hazard removals, increased tree cutting activity and an increase in fault costs. Costs associated with bought in services also increased. These increases were partly offset by the introduction of efficiencies and a reduction in activity relating to link boxes and pillars. The cost of rates, property and IT also increased compared to the previous year. Bad Debt costs and the cost of insurance also decreased which also partly off set the increase in costs.

Actual costs were higher than forecast mainly as a result of increased network costs and reduced Insurance and Bad Debt costs.

Capital expenditure

LOAD RELATED

Actual expenditure was less than forecast mainly as a result of the re-phasing of major projects to take account of outage constraints and planning limitations. A network reinforcement project had been accelerated into 2002/03 to avoid outage constraints whilst some overhead line projects were deferred due to difficulties with obtaining voluntary permissions. Other overhead lines were removed from the reinforcement programme pending condition based rebuild or deferred to future years to take account of major new connections in the same area.

Expenditure in 2004/05 was above the level incurred in 2003/04 mainly due to increased level of expenditure on system reinforcement and an increase in the number of connections completed.

NON LOAD NON FAULT.

The expenditure in 2004/05 exceeded forecast as a result of the requirement to re-profile projects to reduce outage risks, an unexpected replacement of a major transformer and accelerated replacement of high priority protection on critical circuits. Site-specific issues have increased costs on several projects. In addition, there was increased replacement of HV cables with poorly performing sections replaced on a planned basis.

The year-on-year increase is due to a higher level of activity in replacing HV cables, poorly performing overhead line insulators, removal of low clearance hazards and increased undergrounding of circuits associated with overhead line replacement.

FAULT REPLACEMENT

During the price control period ending 2004/05, the business made a strategic decision to make the transition from a regional to a functional business structure. This resulted in the implementation of a dedicated fault restoration and repair business function. In support of this, numerous fault restoration and repair teams have been established on a shift pattern basis and the costs incurred during 2004/05 reflect this transition. These costs were not reflected in the forecast although it is expected that this approach will deliver cost benefits in future years.

Expenditure on fault replacement was higher in 2004/05 when compared to 2003/04 due to an increase in the complexity of faults, which arose during 2004/05.

Scottish Hydro-Electric Power Distribution Ltd

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	43.2	46.7	50.0
<i>Memo: Fault costs expensed</i>	3.1	5.8	4.8
Capital Expenditure			
- Net Load related new assets & reinforcement	14.2	11.0	8.0
- Non-load non-fault new & replacement assets	23.9	26.7	30.4
- Fault replacement	1.0	4.0	2.2
- Non-operational new & replacement assets	0	0.2	0
Total Capital Expenditure	39.1	41.9	40.6

Operating costs

Operating costs have increased by £3.5m from 2003/04 levels.

The primary reason for this increase was the fault related expenditure incurred in the January 2005 storm event in SHEPD territory. The operating costs incurred on this event totalled £2.1m.

In addition to this there have been increases in salary costs due to the inflationary element of salaries, a slight increase in staff levels and a one-off free share award to staff. Also, non storm-related fault costs have increased due to a higher level of overhead line faults and a slightly more expensive mix of underground faults than in 2003/04 along with higher inspection and maintenance costs following an environmental legislation change that required additional substation visits for weed killing activities.

These increases have been offset by continued efficiency savings in all areas of the business. Significant reductions in costs have been achieved in Information Technology and Telecoms costs.

Actual costs incurred in 2004/05 were £3.3m lower than we forecast in our DPCR forecast submission. This was primarily due to the lower actual Information Technology and Telecoms costs than forecast.

Capital Expenditure

Capital expenditure (capex) within the SHEPD licence area was £41.9m. This represents a 3% increase on forecast.

Load related expenditure had been anticipated to fall considerably from a historically high level in 2003/2004. However 'general reinforcement', including £1.0m relating to Distributed Generation, remained at a high level and was the primary contributor to the £3.0m increase from forecast levels in this category.

Non-load non-fault capex had been planned to increase by approximately 25% from the previous year in anticipation of a favourable DPCR settlement. A combination of slower recruitment and lower than expected unit costs for refurbishment work meant that the outturn figure was £3.7m under forecast.

However, there was a substantial increase on the previous year's spend which contributed to a large number of substations replaced, switchgear refurbished and overhead line improvements to the overall benefit of customers. During the 2000 to 2005 period, capex investment has improved network performance in SHEPD. This has been borne out by a better performance than the targets set in Ofgem's quality of supply incentive scheme.

In January 2005 hurricane force winds battered Northern Scotland in what was the worst storm in a generation. Previous investment in the network served to mitigate the worst effects of the storm but nevertheless, major damage was caused with 550 High Voltage faults recorded in 24 hours. Staff from Southern Electric Power Distribution were deployed to assist the SHEPD workforce together with large numbers of linesmen from other Distribution Network Operators and contracting companies. This was the primary contributor to fault replacement costs being greater than forecast.

Southern Electric Power Distribution plc

Operating costs and capital expenditure year ending 31 March 2005

	2003/04 Actual	2004/05 Actual	2004/05 Forecast
£m nominal			
Operating Costs (excl cost of sales and depreciation)	96.5	99.8	108.5
<i>Memo: Fault costs expensed</i>	<i>13.2</i>	<i>14.1</i>	<i>13.7</i>
Capital Expenditure			
- Net Load related new assets & reinforcement	39.1	48.0	50.1
- Non-load non-fault new & replacement assets	50.7	50.2	60.2
- Fault replacement	8.6	11.6	7.6
- Non-operational new & replacement assets	0.3	0.7	0.1
Total Capital Expenditure	98.7	110.5	118.0

Operating costs

Operating costs have increased by £3.3m from 2003/04 levels.

The primary reason for this increase was an increase in salary related costs due to the inflationary element of salaries, a slight increase in staff levels and a one-off free share award to staff.

In addition, storm-related fault costs increased from the 2003/04 level due to a number of lightning storms in the summer of 2004 and non storm-related fault costs increased due to a higher level of overhead line faults and a slightly more expensive mix of underground faults than in 2003/04. Also, higher inspection and maintenance costs have been incurred following an environmental legislation change that required additional substation visits for weed killing activities.

These increases have been offset by a continued drive for efficiency savings in all areas of the business. Significant reductions in costs have been achieved in Information Technology and Telecoms costs.

Actual costs incurred in 2004/05 were £8.7m lower than we forecast in our DPCR forecast submission. This was primarily due to an assumption made in the DPCR forecast submission that pension deficit funding would commence in 2004/05. This, in fact, commenced in 2005/06. In addition, actual Information Technology and Telecoms costs were lower than forecast.

Capital Expenditure

During 2004/2005 capital expenditure (capex) within the SEPD licence area was 6.4 % under forecast levels.

Load related expenditure had been anticipated to rise from 2003/2004 levels and outturned £8.9m higher. This was £1.9m below budget as a result of 'general reinforcement' being slightly lower than anticipated.

Non-load non-fault capex had been planned to increase by approximately 18% from the previous year in anticipation of a favourable DPCR settlement. A combination of slower recruitment, staff diverted to fault works and lower than expected unit costs for refurbishment work meant that the outturn figure was £10.0m less than forecast.

However, capex continued at a level that meant the network was refurbished to a high standard and saw SEP D out-perform the targets set in Ofgem's quality of supply incentive scheme over the past DPCR period. Overhead lines continued to be upgraded with covered conductor at both low and high voltages, substantial lengths of Consac low voltage underground cable were replaced, more of the network automated and large numbers of substations replaced.

Fault expenditure during 2004/2005 was higher than anticipated due predominantly to an increase in Extra High Voltage (EHV) cable faults. There was a general increase in the number of faults experienced on 33kV cables together with a fault on one of the 132kV submarine cables feeding the Isle of Wight. This fault alone cost in excess of £2.5m to repair.

6. Ongoing Work

- 6.1 As noted above, 2004/05 was the first year for which the DNOs have submitted information under the Cost Reporting Rules.
- 6.2 Work is underway to review and refine the rules where necessary to aid the consistency of information reported by all DNOs and its potential usefulness for the next price review. This is an evolutionary process. Ofgem will continue to work with the DNOs to strengthen and improve cost reporting. For next year, our intention is to streamline the data request somewhat, combining similar activities where costs are relatively low and removing or modifying data points that were not useful. We will also begin to consider alternative ways of using the data for cost assessment. We intend to issue the rules for 2005/06 in February/March 2006.
- 6.3 Ofgem's next electricity distribution cost report will cover the year ended 31 March 2006, which is the first year of the DPCR4 price control period. The current intention is to publish this in January 2007. This report will include comparisons to DPCR4 allowances. As the rules become more robust and consistency improves, Ofgem will publish more disaggregated data and analysis, e.g. on costs by activity. Ofgem welcomes views on the type and format of information that users of this report would find useful.
- 6.4 Ofgem would like to thank the DNOs for their co-operation in preparing the rules and data for 2004/05.

Allowances in the Final proposals/Licence Conditions

y/e 31 march	Final proposals ref.	DPCR4 allowance					
		2006	2007	2008	2009	2010	
£m (02/03 prices)							
CN West	Operating costs (excluding pensions)	page 125	72.5	70.0	68.0	66.6	66.0
	less pass through items: Rates	Table 7.3	(22.2)	(21.1)	(20.5)	(20.5)	(20.5)
	Ofgem Licence fee	Table A6	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
	Adjusted Operating cost allowance		49.2	47.8	46.4	45.0	44.4
CN East	Operating costs (excluding pensions)	page 126	75.2	77.7	78.2	76.9	76.2
	less pass through items: Rates	Table 7.3	(21.8)	(25.6)	(27.4)	(27.4)	(27.4)
	Ofgem Licence fee	Table A6	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
	Adjusted Operating cost allowance		52.3	51.0	49.7	48.4	47.7
UU	Operating costs (excluding pensions)	page 127	67.0	64.7	63.1	61.7	60.2
	less pass through items: Rates	Table 7.3	(18.3)	(17.4)	(17.3)	(17.3)	(17.3)
	Ofgem Licence fee	Table A6	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
	Adjusted Operating cost allowance		47.6	46.2	44.7	43.3	41.8
CE NEDL	Operating costs (excluding pensions)	page 128	46.3	47.6	47.2	46.7	46.3
	less pass through items: Rates	Table 7.3	(11.9)	(13.7)	(13.7)	(13.7)	(13.7)
	Ofgem Licence fee	Table A6	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
	Adjusted Operating cost allowance		33.7	33.2	32.8	32.3	31.9
CE YEDL	Operating costs (excluding pensions)	page 129	62.2	60.6	59.0	58.4	57.9
	less pass through items: Rates	Table 7.3	(20.5)	(19.5)	(18.5)	(18.4)	(18.4)
	Ofgem Licence fee	Table A6	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
	Adjusted Operating cost allowance		40.7	40.1	39.5	39.0	38.5
WPD S Wales	Operating costs (excluding pensions)	page 131	43.0	44.5	45.1	44.7	44.3
	less pass through items: Rates	Table 7.3	(10.9)	(12.8)	(13.9)	(13.9)	(13.9)
	Ofgem Licence fee	Table A6	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
	Adjusted Operating cost allowance		31.6	31.2	30.7	30.3	29.9
WPD S West	Operating costs (excluding pensions)	page 130	53.2	55.2	56.0	55.5	55.1
	less pass through items: Rates	Table 7.3	(14.4)	(16.9)	(18.2)	(18.2)	(18.2)
	Ofgem Licence fee	Table A6	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
	Adjusted Operating cost allowance		38.1	37.6	37.1	36.6	36.2
EDFE LPN	Operating costs (excluding pensions)	page 132	60.1	62.6	64.1	63.5	62.9
	less pass through items: Rates	Table 7.3	(18.1)	(21.2)	(23.3)	(23.3)	(23.3)
	Ofgem Licence fee	Table A6	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
	Adjusted Operating cost allowance		41.0	40.4	39.8	39.2	38.6
EDFE SPN	Operating costs (excluding pensions)	page 133	58.8	55.3	51.9	49.5	45.1
	less pass through items: Rates	Table 7.3	(14.2)	(13.4)	(12.8)	(10.9)	(7.0)
	Ofgem Licence fee	Table A6	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
	Adjusted Operating cost allowance		43.6	40.9	38.1	37.6	37.1
EDFE EPN	Operating costs (excluding pensions)	page 134	90.2	90.8	89.9	89.1	88.3
	less pass through items: Rates	Table 7.3	(24.5)	(25.9)	(25.9)	(25.9)	(25.9)
	Ofgem Licence fee	Table A6	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
	Adjusted Operating cost allowance		64.1	63.3	62.4	61.6	60.8
SP Distribution	Operating costs (excluding pensions)	page 135	73.0	77.4	76.8	76.2	75.7
	less pass through items: Rates	Table 7.3	(28.4)	(33.4)	(33.4)	(33.4)	(33.4)
	Ofgem Licence fee	Table A6	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
	Adjusted Operating cost allowance		43.7	43.1	42.5	41.9	41.4
SP Manweb	Operating costs (excluding pensions)	page 136	51.3	50.1	48.9	47.3	46.8
	less pass through items: Rates	Table 7.3	(14.3)	(13.5)	(12.9)	(11.7)	(11.7)
	Ofgem Licence fee	Table A6	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
	Adjusted Operating cost allowance		36.3	35.9	35.3	34.9	34.4
SSE Hydro	Operating costs (excluding pensions)	page 137	47.1	47.9	49.4	50.5	50.2
	less pass through items: Rates	Table 7.3	(9.5)	(11.2)	(13.2)	(14.7)	(14.7)
	Ofgem Licence fee	Table A6	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
	Shetland Balancing costs	Table A6	(7.1)	(7.1)	(7.1)	(7.1)	(7.1)
	Adjusted Operating cost allowance		30.2	29.3	28.8	28.4	28.1
SSE Southern	Operating costs (excluding pensions)	page 138	85.8	90.3	92.1	91.4	90.7
	less pass through items: Rates	Table 7.3	(30.2)	(35.5)	(38.0)	(38.0)	(38.0)
	Ofgem Licence fee	Table A6	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Adjusted Operating cost allowance		54.3	53.5	52.8	52.1	51.4

Capital expenditure allowances (excluding all pension costs)

	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	Total
<i>£m (02/03 prices)</i>															
2005/06															
Net Load	19	33	27	13	18	9	13	19	22	38	21	24	10	38	303
Non load	66	53	57	37	48	22	37	57	61	79	43	46	26	60	691
Sliding scale	7	6	5	3	4	2	3	11	7	13	5	8	3	5	82
QoS	5	2	0	0	1	1	0	0	4	5	0	0	0	5	22
23% opex + total faults	15	16	15	10	13	10	11	13	13	20	13	11	9	17	186
Total	112	110	104	62	83	44	64	99	107	154	83	89	47	125	1,283
2006/07															
Net Load	19	33	27	13	18	9	13	19	22	38	21	24	10	38	303
Non load	66	53	57	37	48	22	37	57	61	79	43	46	26	60	691
Sliding scale	7	6	5	3	4	2	3	11	7	13	5	8	3	5	82
QoS	5	2	0	0	1	1	0	0	4	5	0	0	0	5	22
23% opex + total faults	15	16	14	10	12	9	11	12	13	19	13	11	9	16	182
Total	111	110	103	62	83	44	64	99	106	154	83	89	47	125	1,279
2007/08															
Net Load	19	33	27	13	18	9	13	19	22	38	21	24	10	38	303
Non load	66	53	57	37	48	22	37	57	61	79	43	46	26	60	691
Sliding scale	7	6	5	3	4	2	3	11	7	13	5	8	3	5	82
QoS	5	2	0	0	1	1	0	0	4	5	0	0	0	5	22
23% opex + total faults	14	15	14	10	12	9	11	12	12	19	13	11	9	16	178
Total	111	110	103	62	83	44	64	99	105	154	83	89	47	124	1,276
2008/09															
Net Load	19	33	27	13	18	9	13	19	22	38	21	24	10	38	303
Non load	66	53	57	37	48	22	37	57	61	79	43	46	26	60	691
Sliding scale	7	6	5	3	4	2	3	11	7	13	5	8	3	5	82
QoS	5	2	0	0	1	1	0	0	4	5	0	0	0	5	22
23% opex + total faults	14	15	13	10	12	9	11	12	12	19	13	11	9	16	175
Total	110	109	102	62	83	44	63	99	105	153	83	89	47	124	1,272
2009/10															
Net Load	19	33	27	13	18	9	13	19	22	38	21	24	10	38	303
Non load	66	53	57	37	48	22	37	57	61	79	43	46	26	60	691
Sliding scale	7	6	5	3	4	2	3	11	7	13	5	8	3	5	82
QoS	5	2	0	0	1	1	0	0	4	5	0	0	0	5	22
23% opex + total faults	14	15	13	10	12	9	11	12	11	19	13	11	9	16	172
Total	110	109	102	62	82	44	63	99	105	153	82	89	47	124	1,270
Total for DPCR4															
Net Load	97	164	134	63	88	47	66	93	108	188	107	122	50	192	1,517
Non load	329	267	284	183	240	112	184	286	306	396	215	228	128	299	3,453
Sliding scale	33	31	27	15	21	9	14	55	33	66	27	41	14	26	408
QoS	24	9	0	0	4	6	0	0	21	23	0	0	0	25	112
23% opex + total faults	72	77	69	50	61	47	55	61	61	96	65	54	44	81	892
Total	554	548	513	310	413	219	318	494	528	767	414	445	236	622	6,380
Average annual allowance during DPCR4	111	110	103	62	83	44	64	99	106	153	83	89	47	124	1,276

Network statistics

	Total No of Customers	Length of circuit km		
		Overhead	Underground	Total
CN West	2,364,562	24,082	36,871	60,953
CN East	2,502,085	23,205	46,283	69,488
UU	2,297,496	13,655	45,329	58,984
CE NEDL	1,528,624	15,251	25,449	40,700
CE YEDL	2,192,210	13,873	37,542	51,415
WPD S Wales	1,083,220	18,301	15,785	34,085
WPD S West	1,485,141	28,587	19,970	48,557
EDFE LPN	2,247,653	48	34,550	34,598
EDFE SPN	2,187,084	12,871	37,224	50,095
EDFE EPN	3,464,100	34,649	58,196	92,845
SP Distribution	1,988,756	21,198	38,475	59,673
SP Manweb	1,484,250	21,463	26,186	47,649
SSE Hydro	692,495	31,167	13,518	44,685
SSE Southern	2,785,018	27,678	48,468	76,146