Electricity distribution price control review

Second consultation
- Data and cost commentary appendix

December 2003

Introduction

This appendix contains financial data for each DNO and a commentary on cost savings and the factors underlying the level of costs achieved in the DPCR3 period to 31 March 2003. The commentaries contain explanations of efficiency gains as reported to Ofgem by the DNOs these commentaries do not reflect Ofgem's view on DNO performance. Ofgem's view on DNO performance will be published in later price control documents. Please note also that no view on the relative efficiency of the DNOs compared to each other is contained in this document.

Data provided by the DNOs for consideration in DPCR4 has also been included. This data has not been normalised as yet and should not be used for comparative analysis across DNOs.

As discussed in Chapter 6 further adjustments will be necessary before proper comparison can be made and any attempt to assess relative DNO efficiency using the information included in this appendix may be misleading.

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1. Aquila Networks plc (Aquila)

The following tables and comments contain an analysis of Aquila's operating and capital expenditure.

Summary financial information

DNO name: Aquila Networks	nominal prices	note	2000/01	2001/02	2002/03
Information for consideration in DPCR4					
Net Debt (excluding guarantees)	£m	(1)	[redacted]	591	560
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	47	34	42
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		28	27	12
Fault costs capitalised	£m		7	10	14
Total fault costs	£m		35	37	26
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	6	9	13
Metering		(6)			
Revenue (MAP & MOP)	£m		20	20	20
Operating costs: MAP	£m		0	0	0
MOP	£m		11	9	5
Depreciation	£m		7	8	7
	£m		18	17	12
Capital expenditure	£m		7	8	8
Depreciated replacement cost of metering assets	£m	(5)	[redacted]		22
New connections					
Capital expenditure	£m		30	39	44
Customer contributions	£m		(20)	(23)	(32)
Net expenditure	£m		11	15	12

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

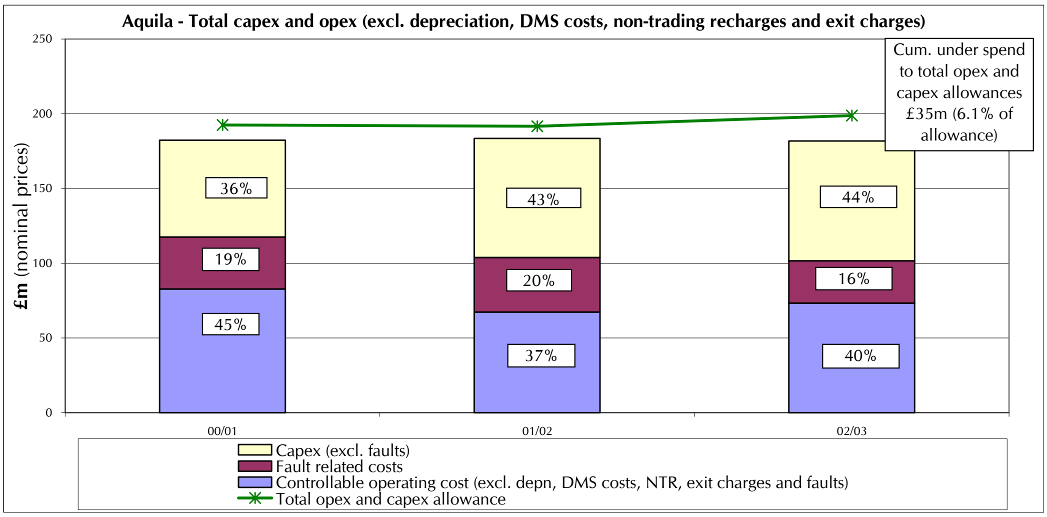
(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Also, Aquila imposed a level of costs to be charged by its related party metering service provider which did not fully reflect all the costs incurred by the service provider.

Summary of cost performance



In DPCR3 to date, Aquila has under spent their allowance in total for opex and capex by £35m. A high-level account of the factors which have influenced these costs and Aquila's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows Aquila's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	22.6	21.2	19.9	19.7
Other cost of sales	8.9	6.7	8.9	12.2
Staff costs	42.6	29.1	12.1	1.8
Direct network costs	15.8	17.3	38.7	49.0
Network rates	22.2	22.3	23.5	25.3
IT costs	16.4	13.4	5.7	1.1
Statutory depreciation	42.7	43.6	41.5	38.0
Other costs	33.3	34.7	23.9	11.4
Total	**204.2**	**188.3**	**174.2**	**158.5**

In addition to ongoing efficiencies, Aquila describes some of the major factors which have affected the cost trends as follows:

- Following the Utilities Act and the creation of a separate entity to hold the Distribution Licence, a dedicated service provider was formed in October 2001. The majority of operating costs, such as staff costs and IT costs, incurred within the service provider are now disclosed as direct network costs;

- Following the implementation of FRS 15 in 2001, Aquila redefined its methodology for the treatment of replacement expenditure following a network fault. This had the impact of classifying more fault costs as capital expenditure and less as operating costs;

- Following the creation of the separate licensee and service provider, and by introducing more detailed cost centres, Aquila was able to more accurately allocate overheads between the activities undertaken. The resulting effect being that more costs have been allocated to capital expenditure and less to operating costs, which in Aquila's view is in line with the nature of the work undertaken; and

- A credit in 2002/03 due to the release of a provision following the settlement of a long-running dispute.

Cost reductions

Aquila has significantly reduced its operating costs since the DPCR 3 review. From discussion with the company and a review of the information provided to us in the HBPQ, Aquila's explanations for this level of performance are set out below.

In general, operating cost reductions have been generated by:

- The creation of two separate business units – Asset Management ("AM") and Engineering Services ("ES") has allowed Aquila to focus on process improvements, which, together with new suites of IT systems, have delivered headcount reductions and reductions in the number of depots/facilities;

- The implementation of SAP, allowing the company to move to a condition based maintenance regime, increasing intervals between maintenance and bringing reductions in headcount;

- A reduction to one control centre following the implementation of new software;

- Improvements in procurement and logistics, including the creation of a single central store and central transport unit, with resultant price reductions, improved delivery performance, shorter lead times and lower inventories;

- Further process and efficiency improvements in other core service providers such as Transport and IT&T;

- Metering activities are provided by an affiliate and savings arose from reductions in headcount, volumes, overheads and reductions in internal profit;

- Insurance costs have reduced since June 2001 since the company has been unable to purchase storm cover for the network at an acceptable cost; and

- Recently, duplicated overhead functions within business units have now been eliminated to move to a centrally managed, locally delivered framework for support services, delivering headcount reductions and streamlining functions, although most of the savings will be delivered after 2002/03.

A combination of these efficiencies has reduced headcount (FTE basis) in the company and the service provider from the beginning of 2000/01 to end 2002/03 by a figure approaching 10%. All initiatives have been supported by changes in human resource practices with flexible contracts and incentives for levels of service delivery. It should be noted that severance costs are born by Midlands Electricity plc and not recharged to the distribution business in accordance with group policy, consistent with the regulatory framework.

Faults and interruptions

Total fault costs peaked in 2001-02 and declined significantly in 2002-03. This is due to a combination of factors including higher levels of faults in 2002, partly caused by severe flooding affecting underground cables. Also, changes in accounting methodology in 2001 increased the amount of overheads allocated to fault activities, which impacted 2000-01 and 2001-02 to a greater extent than 2002-03.

Aquila has sought to manage fault costs and fault levels by:

- the installation of additional protection devices, remote control devices, network reconfiguration and reduction of pre-arranged interruptions by using live-line working techniques and mobile generation;

- the targeted replacement of overhead lines and Consac cables and introduction of more sophisticated rural protection arrangements; and

- shortening the tree-cutting period from 5 to 3 years.

Aquila's network was affected by two storms in 2000 and another in October 2002. The former was covered by insurance minimising the financial impact, whilst the latter was not, as increasing insurance premiums and lack of available insurance led Aquila to carry this risk internally, following the liquidation of their insurer – Independent. Aquila has made negligible Guaranteed Standard of Performance compensation payments and the level of ex-gratia compensation payments remains constant at a low level.

The number and duration of interruptions have improved despite an increase in the number of faults. The company consider that this indicates that it is managing supply restoration better and has achieved cost savings.

Aquila expects to achieve its IIP 2004/05 quality of supply Customer Interruptions (CI) target although the Customer Minutes Lost (CML) target may be more challenging.

Asset Management

- Following a company restructure, a review was carried out to redesign asset management processes. Systems and processes have been developed and refined both with respect to R&M and Capex;

- The major changes in R&M have been a reduction in site clearance and maintenance activities, battery maintenance, operation restriction clearances, 132kV contract maintenance, tower painting and pole inspection frequency. In addition, there have been extensions of maintenance periods for pole-mounted plant. This has been supported by the implementation of a new suite of IT systems;

- Risk management techniques have been developed at a high level of business planning and all network programs are subject to benefit analysis or cost/benefit analysis. The use of Health Indices is currently being developed;

- A high level Network Strategy document sets direction for the business. This is subsequently translated into work plans via the Primary Network and Secondary Network Plans;

- The asset database retains condition information and facilitates ranking of potential problems and comparisons of data collected on the same asset types enabling trends to be identified; and

- Longer-term replacement is forecast using Replacement Curve modelling.

Capex

Aquila has explained the variance against its own DPCR3 forecast which for capital expenditure net of Quality of Supply was close to Ofgem's final allowance. The level of saving has been provided at a general level with limited sub-division into the capital expenditure drivers of Load and Non-Load Related Expenditure.

Load related expenditure (LRE) variance

The actual expenditure for gross LRE reflects the following:

- New business is higher than Ofgem's allowance. This is attributed by Aquila to higher than forecast growth in the commercial sector; and

- Reinforcement expenditure is also higher than Ofgem's allowance. This is primarily driven by the need to increase headroom in the network in order to meet the requirements of the security of supply network planning standard and voltage issues that together impact on reinforcement need.

Non load related expenditure (NLRE) variance

Actual expenditure for NLRE is lower than the Ofgem allowance. This is primarily driven by variance in replacement activity.

A reduction in capital expenditure at this point in time due to the Foot and Mouth epidemic has been recognised by Aquila although it is intended to recover this situation during the remainder of the current review period.

Variances due to diversion and metering activities have also been identified.

Reported Capital Efficiency Gains

Aquila has reported efficiency gains against its initial DPCR3 submission. These gains have been realised across a number of activities that are common to both Load and Non-Load Related expenditure classes.

- The implementation of a new Asset Management suite of systems is believed to have made available improved condition data as well as better decision support tools and trend analysis. Together these improvements have contributed to extending asset lives as well as improved system and investment planning;

- Operational and process improvements, including organisation restructuring as described earlier, are reported to have led to reduced overheads associated with capital activities;

- A further efficiency gain has been identified as a consequence of a business process review of engineering support services; and

- Procurement and out-sourcing savings have been generated.

2. East Midlands Electricity Distribution (EMED)

The following tables and comments contain an analysis of EMED's operating and capital expenditure.

Summary financial information

DNO name: East Midlands Electricity	nominal prices		2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)		572	544
Guarantees	£m			0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	37	31	29
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		26	28	29
Fault costs capitalised	£m		4	1	5
Total fault costs	£m		30	29	34
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	5	2	5
Metering		(6)			
Revenue (MAP & MOP)	£m		18	17	17
Operating costs: MAP	£m		0	0	0
MOP	£m		11	6	7
Depreciation	£m		6	5	4
	£m		17	11	11
Capital expenditure	£m		9	10	10
Depreciated replacement cost of metering assets	£m	(5)			20
New connections					
Capital expenditure	£m		47	49	46
Customer contributions	£m		(33)	(42)	(39)
Net expenditure	£m		14	7	7

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

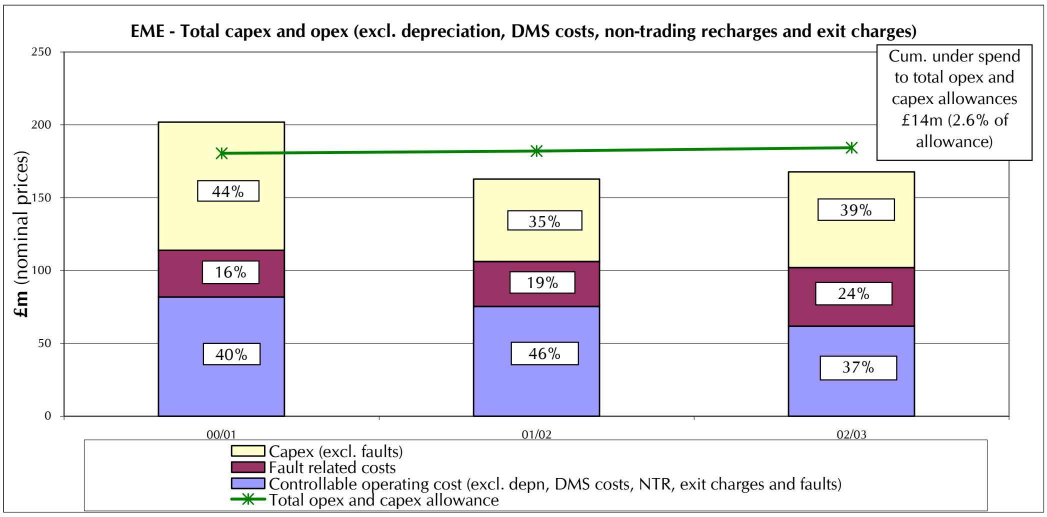
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, EMED has under spent their allowance in total for opex and capex by £14m. A high-level account of the factors which influenced these levels of costs and EMED's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows EMED's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	21.2	21.0	19.8	18.5
Other cost of sales	5.5	4.8	8.4	7.6
Staff costs	54.5	25.9	20.5	20.5
Direct network costs	20.7	21.6	25.0	23.2
Network rates	19.6	22.4	23.4	24.6
IT costs	26.7	18.2	10.5	8.1
Statutory Depreciation	41.0	38.1	35.7	35.9
Other costs	82.6	80.1	23.7	26.5
Total	**271.8**	**232.1**	**167.0**	**164.9**

In addition to ongoing efficiencies, EMED describe some of the major factors which have affected the cost trends as follows:

- EMED undertook a major restructuring program in 2000 resulting in significant re-organisation costs in both 2000 and 2001 (circa £75m and £10m respectively). The majority of these re-organisation costs were severance costs as staffing levels in 2000 were approximately 34% higher than in 2001, with work transferred to external service providers. This has seen a significant decrease in staff costs and 'other' costs from 2000 to 2002;

- In 2001, EMED completed the outsourcing of its metering management services operations. As part of this process, a review of the carrying value of metering assets was performed, and a significant write-down in metering assets was taken in 2001 (circa £60m);

- From September 2000, EMED centralised management of the business from new offices at Pegasus Park. This resulted in the closure and disposal of 24 existing premises enabling EMED to target lower overheads and reduce staff costs; and

- The major reorganisation in 2000 reduced the cost base significantly. This efficiency has been maintained.

Cost reductions

EMED has reduced its operating costs since the start of DPCR3 and have outperformed the allowance. The major reasons behind this outperformance have been described in the cost trend analysis above. Specific areas of cost reductions include:

- Staff costs have reduced significantly from 2000 due to the reduction in employee numbers resulting from restructuring and outsourcing. There was an approximate 34% reduction in staff numbers from 2000 to 2001, balanced by major outsourcing programme using external staff to deliver core services and metering services; and

- IT costs have reduced due to implementation of efficiencies within the IT department. Significant costs were incurred in earlier years to implement those efficiencies.

Rationalisation and productivity improvements

Specific efficiency initiatives identified by EMED are as follows:

- Transferring IT systems from mainframe to smaller server based systems to reduce running costs and maintenance as well as improvement to service;

- Managing External Service Providers and suppliers better to improve the procurement process and reduce costs;

- Utilising field staff more efficiently in order to reduce overtime levels and improve workforce moral, performance management and changes to job specifications;

- Major reductions in overheads; and

- Provision of computer devices to field staff to improve productivity and efficiency.

Asset management changes

- EMED has developed a robust risk-based process covering both load and non-load investment. These processes for identifying investment needs have enabled EMED to develop investment plans to maintain current network risks at an appropriate level, whilst meeting specific price control and EMED targets; and

- EMED have managed capital constraints by having a stronger focus on short term risks and performance targets, mitigating these risks by minimum capital cost solutions and deferring spend where possible. This approach has been viable over the DPCR3 period but EME report that it is not sustainable beyond DPCR3.

A review of maintenance practices indicates that EMED has focused its inspection and maintenance activities on risk management principles.

- EMED has reduced inspection and maintenance frequencies. Safety inspections of substations and lines are more frequent than condition assessments and include special inspections of vulnerable sites;

- EMED uses Reliability Centred Maintenance techniques for substation maintenance procedures and carries out oil tests on 11kV switchgear to determine appropriate maintenance intervals. EMED is carrying out trials of statistical sampling of oil in switchgear to reduce the need for invasive maintenance; and

- Condition inspection data is managed by hand held technology and is due to be completed on the outstanding 20% of overhead line assets.

EMED's investment programme is based on risk management principles.

- All company risks are identified and quantified in a comprehensive risk register;

- Investment options are optimised for major projects and programmes of work by evaluating risk reduction and quality of supply benefits;

- EMED uses health indexing of assets including condition and design characteristics to improve prioritisation of investment;

- Each project and programme is subject to a detailed risk assessment using a Condition Analyser and Performance Analyser as a routine part of investment appraisal;

- Post investment appraisals are used to refine programmes and update unit costs;

- Following Ofgem's Asset Risk Management Review (ARM) in 2002, EMED is improving the documentation of processes and EMED has also developed a cable analyser that uses cable performance and design data from both internal and external sources; and

- Medium term and long term forecasts of asset replacement are based on a modified birthday replacement model to validate the risk assessed programme of projects and to identify deferment of asset replacement.

EMED's IT systems are based on a number of databases with suitable interfaces and data is managed by an external central records update service provider to quality controlled standards. EMED carries out data audits and training of service provider operatives collecting data in the field.

Faults and Interruptions

Total fault costs have increased by 25% between 2001 and 2003. The majority of this increase is due to the impact of storms.

The area has been affected by a number of storms over the period. Whilst most events were covered by insurance, some events were not.

- During the period under review, EMED undertook investments to improve quality of supply in the areas of remote control protection, LV generation, tree management and operational initiatives;

- Specific improvement initiatives include the installation of Pole Mounted Auto Reclosers, Auto Sectionalising Links, Ground Mounted Remote Control Actuators and Remote Earth Fault Indicators;

- A detailed avenue tree clearance program implemented in 2002 and 2003 has seen the number of tree related incidents fall from 2001 to 2003;

- Fault costs have fluctuated over the years due to a change in the mix of incidents. The number of smaller LV incidents decreased by approximately 10% from 2001 to 2003 as a result of those initiatives identified above. However, there were a larger number of HV incidents in 2003 which have a higher associated cost and therefore increased fault costs in 2003;

- EMED continue to focus on initiatives that will improve quality of supply;

- EMED is finding meeting its IIP 2004/05 CML targets challenging; and

- EMED has already seen a slight downturn in its Medium Term Performance of asset reliability which together with a prediction of future asset condition, EMED suggests will need to be addressed by a significant increase in the non-load related expenditure allowance in DPCR4.

Capex

In EMED's view, restrictions on DPCR3 allowances, the high level of customer driven work, wayleave terminations and a specific switchgear safety issue has put pressure on investment which they would have wished to make on asset replacement and quality of supply.

Load related expenditure variance

- The overspend on new connections is mainly due to additional new non-residential development, especially around transport corridors;

- Reinforcement expenditure is currently lower than the DPCR3 allowance but is expected to be similar to the DPCR3 allowance for the five-year DPCR3 period on completion of major projects to reinforce Nottingham and Burton.

Non-load related expenditure variance

- EMED expenditure in the first year of DPCR3 included significant undergrounding of overhead lines which was a feature of their Vision 2020 policy for network restructuring, which EMED concluded was inconsistent with the significantly lower DPCR3 capital allowance allowed by Ofgem;

- EMED has experienced a high level of wayleave terminations (requiring network diversions) to which EMED has diverted funds from network replacement;

- Overhead line refurbishment has tended to take a short term approach which EMED indicates may be sub-optimal but was required in order to comply with DPCR3 capital allowances;

- Switchgear replacement has been deferred by use of operational restrictions and EMED indicates that this policy is not sustainable into DPCR4;

- EMED has concentrated on replacement work on the 11 kV network which gives the maximum quality of supply benefit in the short term; and

- EMED intends to significantly increase the number of remote control points on the 11kV system by installing some additional 800 points of remote control during the remaining two years of DPCR3.

Reported Efficiency Gains

EMED has implemented a number of efficiency initiatives and those that impact on capital expenditure include the transfer of asset data to the central SAP system, work programme planning and E commerce. Non IT initiatives include management of suppliers and external service providers and field staff productivity improvements, focusing the work programme on immediate need and reduction of overheads.

3. EDF Energy Networks (EPN) plc (EPN)

The following tables and comments contain an analysis of EPN's operating and capital expenditure.

Summary financial information

DNO name: EDF Energy Networks (EPN) plc	nominal prices		**2000/01**	**2001/02**	**2002/03**
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)		706	757
Guarantees	£m			0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	38	28	51
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		10	10	20
Fault costs capitalised	£m		9	10	19
Total fault costs	£m		19	20	38
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	9	10	19
Metering		(6)			
Revenue (MAP & MOP)	£m		16	15	19
Operating costs: MAP	£m		0	0	0
MOP	£m		6	7	9
Depreciation	£m		4	4	20
	£m		10	11	29
Capital expenditure	£m		8	11	13
Depreciated replacement cost of metering assets	£m	(5)			29
New connections					
Capital expenditure	£m		40	51	67
Customer contributions	£m		(34)	(42)	(64)
Net expenditure	£m		6	10	3

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

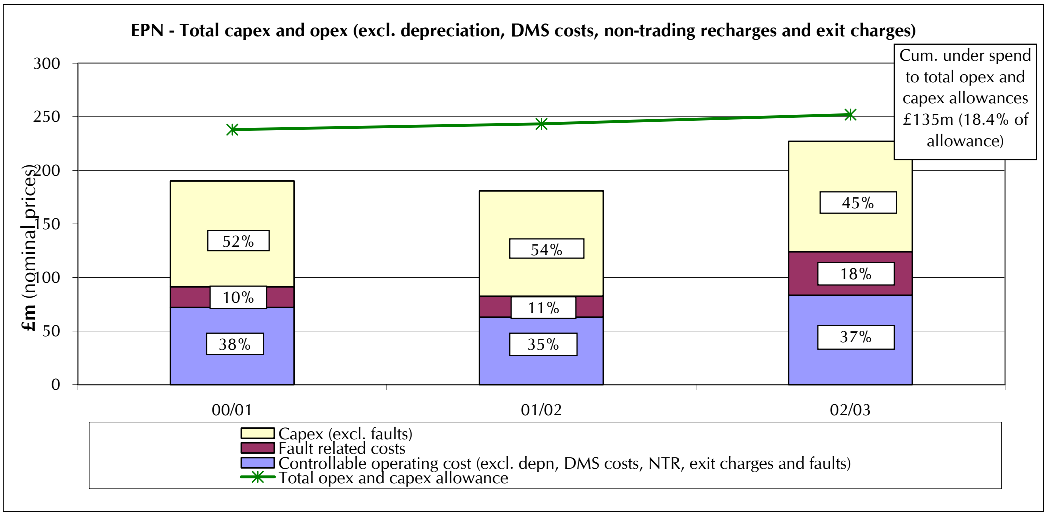
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of Cost Performance



In DPCR3 to date, EPN has under spent their allowance in total for opex and capex by £135m. A high-level account of the factors which have influenced these costs and EPN's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below show EPN's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	22.7	22.3	22.2	18.1
Other cost of sales	15.4	10.5	0.1	0.0
Staff costs	40.8	1.5	1.6	1.6
Direct network costs	12.7	33.9	29.2	59.3
Network rates	26.2	25.9	26.1	25.2
IT costs	9.9	0.8	1.4	1.4
Statutory Depreciation	50.0	23.2	30.9	41.9
Other costs	42.6	20.2	14.4	18.2
Total	**220.3**	**138.3**	**125.9**	**165.7**

EPN describe the major factors which have affected the volatility in cost trends as follows:

- A joint venture service provider, 24seven, was created in April 2000 to manage the operation of the distribution networks of EPN and LPN. This was seen as a way to achieve the benefits normally associated with a merger or acquisition creating a new relationship between asset ownership and asset management to drive further improvements in service and efficiencies;

- The impact of 24seven in 2001 was to significantly reduce Costs of sales, Staff costs, IT costs, Premises costs and Other costs in the EPN accounts while increasing Direct Network Costs, representing the charges from 24seven in accordance with their contract with EPN;

- Depreciation expense was impacted by a restatement of asset lives in 2000/01 to comply with FRS15, in 2001/02 to reverse a revaluation of assets undertaken by TXU and in 2002/03 to realign with EDF depreciation policies;

- Metering operations were outsourced to a third party provider in 2000/01;

- 2000 included significant restructuring charges which were transferred from EPN to TXU at the time of the purchase by EDF. Further restructuring costs have been incurred in 2002 and 2003;

- The trends in actual costs incurred by 24seven are not reflected in the accounts of EPN because the charges from 24seven are governed by the fees set in the contract between the parties;

- Following the acquisition in 2002 of EPN and 24seven by EDF Energy it became apparent to EDF that the charges being levied by 24seven were not cost reflective in that they were not recovering the overall costs of the activities and there was an imbalance in the charges to LPN and EPN. The fees from 24seven for the fixed price activities were revised with effect from April 2002 resulting in an increase in these charges to EPN of around 60% (which equates to an increase in the total 24seven fees of around 19%);

- The rules for capitalisation of charges were amended from April 2002 for consistency between LPN and EPN. The new treatment was applied from April 2002 and decreased the proportion of charges from the service provider that were capitalised by EPN and therefore increase the proportion of those charges that appear as operating costs;

- Other Operating Costs were significantly lower in 2002, mostly as a result of a lower corporate management charge than in the previous or the subsequent years; and

- Other Operating Costs in 2003 increased as a result of Guaranteed Standards of Performance payments connected with the October 2002 storms.

Cost reductions

EPN has significantly reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, EPN's explanations for this level of out performance are set out below:

- The most significant cost reduction affecting EPN in the period was the implementation of the contractual relationship between EPN and 24seven in April 2000. Under this relationship costs were set for a five year period in accordance with expectations of costs savings within 24seven; and

- The level of charges represented significant savings in operating costs for EPN in the first year of operation but restricted the opportunity for further cost reductions internally.

Rationalisation and productivity improvements

The main efficiencies in the period have been achieved within 24seven; EPN described these efficiencies as follows.

- Consolidation of all control and call centre activities into one site;

- Implementation of a single accounting and personnel IT system that provided the opportunity for savings in support costs and improved the quality of management information;

- Greater emphasis on the effective management of field staff leading to greater productivity of staff and therefore reduced reliance on contracting staff and the opportunity to reduce staffing levels;

- The commercial pressure created by the separation of asset ownership and operation has increased the proportion of work plans that are delivered on time and to budget;

- Manpower reductions have provided the opportunity for savings in transport costs;

- The combined purchasing power of an integrated provider has allowed savings in procurement costs; and

- Implementation of three key IT systems for network management, asset management and telephone incident management has improved the effectiveness and efficiency of the business.

Continuous changes in both business information systems and personnel within EDF businesses has meant that detailed information about individual efficiency initiatives has not been available for this review to date.

Asset management changes

- EPN have formalised its asset management policy in the Network Asset Management Plan (NAMP) and Networks Branch policies. The NAMP employs a number of processes to identify and prioritise risks and to determine appropriate work plans both for R&M and Capex and is reviewed on an annual basis;

- Risk assessment is increasingly becoming an embedded process in all key activities and Condition Importance Rating (CIR) is being used to focus inspection and maintenance activity on those assets that are critical to the performance of the network and the business;

- The CIR methodology uses a probability index, severity factor and external driver weighting to determine a rating that can be used to determine the condition assessment criteria and, when multiplied by the asset population, be used to prioritise R&M activity;

- System Wide Reliability Centred Maintenance ('RCM') is currently being implemented as part of the integration with EDF Energy;

- A network condition report is updated annually identifying key issues to be addressed and informing decision making. Difficulties in the monitoring of the condition of cables are being addressed by the use of partial Discharge testing techniques; and

- In the medium to long term, asset replacement requirements are determined with the assistance of Replacement Curve modelling.

Faults and Interruptions

Operational fault cost expenditure increased significantly in 2003 after steady costs in 2001 and 2002. This increase was due to a combination of factors including:

- Significant costs experienced during the storms of October 2002, including provision for significant GOSP compensation payments;

- The increase in charges from the service provider from April 2002 (see above).

24seven have sought to manage their costs incurred in dealing with faults by implementing a new fault reporting system to monitor and record faults, installation of automated remote post fault restoration systems and by improving communication between staff to ensure speedy response to faults.

EPN have sought to manage their costs in the event of storms by obtaining third party insurance for lightning and storms damage. This insurance was in operation for the October 2002 storms although to date no payment has been received.

EPN expects that the 2004/05 IIP targets for both CI and CML will be achieved on the assumption that Ofgem continues to apply the reasonable exemption of major storm events but that both targets are challenging.

EPN report that the number and duration of interruptions have fallen despite an increase in the number of faults. EPN state that this indicates that they have become better at restoring supply and have achieved cost savings.

Capex

Over the three-year period reviewed EPN has under spent against the DPCR3 allowance. This under expenditure has arisen in both the Load Related and Non-Load Related expenditure categories.

EPN has explained the reasons for the expenditure variance with respect to the company's submission and in some cases the explanations apply to both the Load Related and Non-Load Related categories.

Load related expenditure variance

EPN has identified under expenditure due to the following activities:

- Lower than forecast load growth has allowed savings in reinforcement expenditure while the level of new connections activity is broadly consistent over a three-year period with its submission;
- Identifying synergies between load and non-load related projects;
- Network redesign and re-scoping of the original investment proposal;
- Customer driven rephasing and timing changes;
- Lower than forecast take up of a number of commercial developments;
- Better forecasting techniques;
- Improved project management skills have constrained project overrun and enhanced project returns; and
- Increased utilisation of assets has been made possible through improved thermal modelling techniques.

Non-load related expenditure variance

EPN has identified under expenditure due to the following activities:

- Identifying synergies between load and non-load related projects;
- The replacement programme of Minor Works has reduced expenditure against the 11kV switchgear and remote control programme;
- Savings in the overhead line programme primarily driven by condition assessment and prioritised refurbishment programme as opposed to wholesale replacement;
- Automation is being introduced that produces quality of supply improvements at a much lower cost than alternatives envisaged at DPCR3;
- Increased cost due to additional expenditure on substation civil works has occurred;
- Metering expenditure has decreased from previously forecast levels. This under expenditure is attributed to savings in procurement, reduced volumes, cancelled replacement technology programmes and closer control of internal fixed costs;

- EPN has also indicated that the actual expenditure for non-load related metering activities is in excess of the DPCR3 allowance;

- Variances in the EHV Major Projects activity have occurred. However, whilst large variances have been reported in particular years, those variances have in aggregate, due to positive and negative swings, resulted in a minimal change being reported at the end of the three-year period; and

- Variances within the Major Projects activity are as a consequence of two main drivers, re-phased schemes and timing changes, as well as improved condition assessment techniques.

Other Reported Efficiency Gains

EPN has reported that savings have been achieved through improved procurement practices, but that these may be unsustainable into the future. These practices have been ascribed to enhanced contract letting arrangements for larger tranches of work as well as standardised technical specification providing enhanced supplier choice and economies of scale.

4. EDF Energy Networks (LPN) plc (LPN)

The following tables and comments contain an analysis of LPN's operating and capital expenditure.

Summary financial information

DNO name: EDF Energy Networks (LPN) plc	nominal prices		2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	470	491
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	44	40	36
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		11	12	16
Fault costs capitalised	£m		4	5	9
Total fault costs	£m		15	16	25
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	4	5	9
Metering		(6)			
Revenue (MAP & MOP)	£m		15	17	14
Operating costs: MAP	£m		0	0	0
MOP	£m		4	3	4
Depreciation	£m		7	7	16
	£m		11	10	20
Capital expenditure	£m		13	16	15
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	21
New connections					
Capital expenditure	£m		32	35	43
Customer contributions	£m	(7)	(27)	(49)	(38)
Net expenditure	£m		5	(14)	5

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

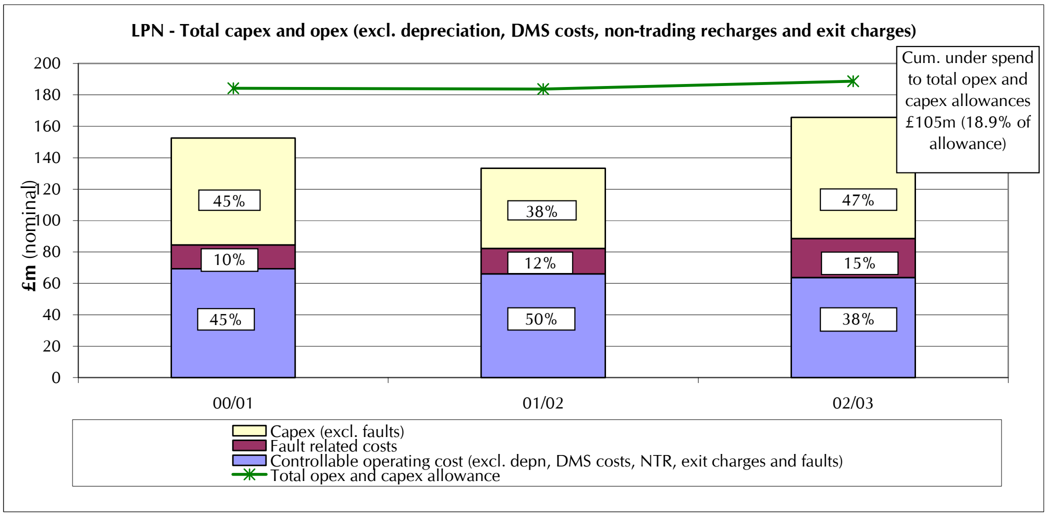
(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

(7) Customer contributions for 01/02 contained £14.6m release of old credit balances.

Summary of Cost Performance



In DPCR3 to date, LPN has under spent their allowance in total for opex and capex by £105m. A high-level account of the factors which have influenced these costs and LPN's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below show LPN's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	2000 £m	2001 £m	2002 £m	2003 £m
Transmission exit charges	18.7	18.4	18.3	16.7
Other cost of sales	19.8	3.2	2.2	0.1
Staff costs	42.8	2.7	3.3	3.5
Direct network costs	11.3	37.6	28.6	35.6
Network rates	21.5	21.5	21.6	20.7
IT costs	29.3	4.8	2.5	1.7
Statutory Depreciation	59.3	47.1	50.0	48.1
Other costs	15.7	10.8	19.1	16.7
Total	**218.4**	**146.1**	**145.6**	**143.1**

LPN describes the major factors which have affected the volatility in cost trends as follows:

- A joint venture service provider, 24seven, was created in April 2000 to manage the operation of the distribution networks of EPN and LPN. This was seen as a way to achieve the benefits normally associated with a merger or acquisition creating a new relationship between asset ownership and asset management to drive further improvements in service and efficiencies;

- The impact of 24seven in 2001 was to significantly reduce Costs of sales, Staff costs, IT costs, Premises costs and Other costs in the LPN accounts while increasing Direct Network Costs, representing the charges from 24seven in accordance with their contract with LPN;

- Depreciation expense was impacted by a restatement of asset lives in 2000/01 to comply with FRS15 and in 2002/03 to realign with EDF depreciation policies;

- Metering operations were outsourced to a related party provider in 2000/01;

- Restructuring charges were included in LPN's costs in 2000 and 2002 with further charges in 2003;

- The trends in actual costs incurred by 24seven are not reflected in the accounts of LPN because the charges from 24seven are governed by the fees set in the contract between the parties;

- Following the acquisition in 2002 of EPN and 24seven by EDF Energy it became apparent to EDF that the charges being levied by 24seven were not cost reflective in that they were not recovering the overall costs of the activities and there was an imbalance in the charges to LPN and EPN. The fees from 24seven for the fixed price activities were revised with effect from April 2002 resulting in an increase in these charges to LPN of around 34% (which equates to an increase in the total 24seven fees of around 13%); and

- The rules for capitalisation of charges were amended from April 2002 for consistency between LPN and EPN. The new treatment was applied from April 2002 and increased the proportion of charges from the service provider that were capitalised by LPN and therefore decreased the proportion of those charges that appear as operating costs.

Cost reductions

LPN has significantly reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, LPN's explanations for this level of out performance are set out below.

- The most significant cost reduction affecting LPN in the period was the implementation of the contractual relationship between LPN and 24seven in April 2000. Under this relationship costs were set for a five year period in accordance with expectations of costs savings within 24seven; and

- The level of charges represented significant savings in operating costs for LPN in the first year of operation but restricted the opportunity for further cost reductions internally.

Rationalisation and productivity improvements

The main efficiencies in the period have been achieved within 24seven; LPN described these efficiencies as follows:

- Consolidation of all control and call centre activities at one site;
- Implementation of a single accounting and personnel IT system that provided the opportunity for savings in support costs and improved the quality of management information;
- Greater emphasis on the effective management of field staff leading to greater productivity of staff and therefore reduced reliance on contracting staff and the opportunity to reduce staffing levels;
- The commercial pressure created by the separation of asset ownership and operation has increased the proportion of work plans that are delivered on time and to budget;
- Manpower reductions have provided the opportunity for savings in transport costs;
- The combined purchasing power of an integrated provider has allowed savings in procurement costs; and
- Implementation of three key IT systems for network management, asset management and telephone incident management has improved the effectiveness and efficiency of the business.

Continuous changes in both business information systems and personnel within EDF businesses has meant that detailed information about individual efficiency initiatives has not been available for this review to date.

Asset management changes

- LPN contracted with 24seven with a 5 year rolling plan referred to as the Network Asset Management Plan (NAMP). The NAMP employs a number of processes to identify and prioritise risks and to determine appropriate work plans both for R&M and Capex and is reviewed on an annual basis;
- Risk assessment is increasingly becoming an embedded process in all key activities and Condition Importance Rating (CIR) is being used to focus inspection and maintenance activity on those assets that are critical to the performance of the network and the business;
- The CIR methodology uses a probability index, severity factor and external driver weighting to determine a rating that can be used to determine the condition assessment criteria and, when multiplied by the asset population, be used to prioritise R&M activity;

- System Wide RCM is currently being implemented as part of the integration with EDF Energy;

- A network condition report is updated annually identifying key issues to be addressed and informing decision-making. The collation of information on the condition of underground cables is being addressed by the use of partial Discharge testing techniques; and

- In the medium to long term, asset replacement requirements are determined with the assistance of Replacement Curve modelling.

Faults and interruptions

Operational fault cost expenditure increased in 2002 and more significantly in 2003. The increase in the 2003 charges for faults was in part a result of the increase in charges from the service provider from April 2002 (see above).

24seven have sought to manage their costs incurred in dealing with faults by implementing a new fault reporting system to monitor and record faults, installation of automated remote post fault restoration systems and by improving communication between staff to ensure speedy response to faults.

Only a very small proportion of the LPN network is overground and therefore LPN does not insure for lightning or storms, however, LPN does maintain insurance for equipment damaged by severe weather flooding.

LPN believes that the IIP network performance CI and CML targets are challenging but achievable.

The company reports that the number and duration of interruptions have fallen despite an increase in the number of faults. LPN state that this indicates that they has become better at restoring supply.

Capex

Over the three-year period reviewed, LPN has under spent against the DPCR3 allowance. This under expenditure has arisen in both the Load Related and Non-Load Related expenditure categories.

LPN has explained the reasons for the expenditure variance with respect to the company's submission and in some cases the explanations apply to both the Load Related and Non-Load Related categories.

Load related expenditure variance

Under expenditure in this category is reported by LPN to be due to:

- Network redesign and re-scoping of the original investment proposal;

- Identifying synergies between load and non-load related projects;

- Customer driven rephasing and timing changes;
- Lower than forecast take up of a number of commercial developments;
- Increased utilisation of assets has been made possible through improved thermal modelling techniques;
- Better forecasting techniques;
- Improved project management skills have constrained project overrun and enhanced project returns; and
- Load growth within older parts of the network with minimum headroom has offset the level of reinforcement under expenditure to a degree.

Non-load related expenditure variance

LPN has identified an under expenditure in this category due to:

- Network redesign and re-scoping of the original investment proposal through condition monitoring or the identification of alternative engineering options;
- Identifying synergies between load and non-load related projects;
- Condition-based assessment has enabled certain replacement activity to be deferred or assets have been refurbishment as opposed to complete replacement;
- Extensive use of automation has delivered quality of supply improvements;
- A policy of targeted replacement has contributed to savings;
- Load related metering expenditure is lower than anticipated but non load related expenditure has been higher as a result of increased meter recertification;
- EHV Major Projects expenditure is lower due to redesign and re-scoping of specific projects and timing changes in both the new connections category and deferred or alternative replacement activity; this has been offset by additional costs arising from a reassessment of network replacement needs and a lower contribution from load related reinforcement; and
- Savings in minor works asset replacement through deferment has been delivered; this has been offset by additional costs in other asset classes.

Other Reported Efficiency Gains

- Improved procurement practices have generated savings due to contract letting arrangements for larger tranches of work with economies of scale, but that these may be unsustainable into the future. The use of standard technical specifications has increased supplier choice.

5. EDF Energy Networks (SPN) plc (SPN)

The following tables and comments contain an analysis of SPN's operating and capital expenditure.

Summary financial information

DNO name: EDF Energy Networks (SPN) plc		nominal prices	2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	444	430
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	46	49	53
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		9	9	9
Fault costs capitalised	£m		11	12	13
Total fault costs	£m		19	20	22
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	11	12	13
Metering		(6)			
Revenue (MAP & MOP)	£m		17	19	19
Operating costs: MAP	£m		0	0	0
MOP	£m		9	7	8
Depreciation	£m		5	5	5
	£m		14	12	13
Capital expenditure	£m		12	15	11
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	22
New connections					
Capital expenditure	£m		24	22	24
Customer contributions	£m		(23)	(26)	(25)
Net expenditure	£m		1	(4)	(0)

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

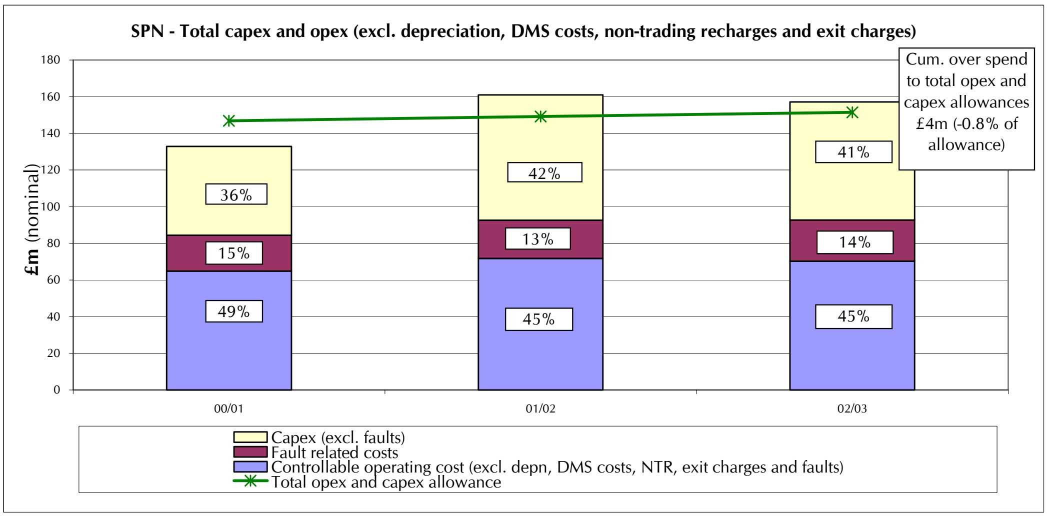
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, SPN has over spent their allowance in total for opex and capex by £4m. A high-level account of the factors which have influenced these costs and SPN's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows SPN's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	17.6	17.0	18.8	17.1
Other cost of sales	3.6	5.4	4.7	4.4
Staff costs	35.6	22.7	17.1	20.0
Direct network costs	4.8	17.4	18.2	20.8
Network rates	15.5	15.3	15.4	14.9
IT costs	19.7	12.1	12.9	13.0
Statutory depreciation	51.4	34.3	30.5	38.0
Other costs	15.9	-0.3	8.3	7.5
Total	**164.1**	**123.9**	**125.9**	**135.7**

SPN describe some of the major factors which have affected the cost trends as follows:

- Introduction of new technology and reliability centred maintenance;
- Step change reduction in the depreciation expense in 2001 from 2000 arises from a revision of asset lives following implementation of FRS 15;
- Accelerated amortisation in 2003 of 1998 DMS costs to align with group policy and realignment of all other useful lives to EDF basis;

- Changes to corporate and management charges and recoveries from shared services, reducing costs significantly in 2001 and rising in subsequent years;

- Outsourcing of metering activities;

- Structural changes delivering reduction in staff numbers;

- Productivity and process improvements;

- Revised the treatment of fault costs from April 2000 resulting in an increased level of cable and line fault costs being expensed and less capitalised; and from April 2001 system changes for classifying fault costs were made which had some impact on the overall level of fault costs capitalised; and

- Overhead allocation rules were reviewed and revised twice during the period 2000/1 to 2002/3 to reflect structural changes in the business, marginally increasing the level of direct overheads and other costs capitalised.

Cost reductions

Since 2000, SPN's operating costs have been increasing and from discussion with the company and a review of the information provided to us in the HBPQ, SPN's explanations for its level of performance are set out below.

In general, operating cost reductions have been generated by:

- Rationalisation and productivity improvements (see below);

- Reductions in layers of management to reduce overheads;

- Better management of staff welfare reducing accidents and short term absence; and

- Introduction of new technology encompassing network, asset location and fault management.

Headcount (FTE basis) has been reduced in the company from the beginning of 2000/01 to end 2002/03 by a figure approaching 4%.

These reductions were offset by cost pressures arising from increases in:

- insurance, pensions, tree cutting, cable repair costs, storm and metering expenditure; and

- unremunerated obligations, e.g. LC25, Street Works, Asset Risk Management and IIP.

Rationalisation and productivity improvements

SPN described their efficiencies as follows.

- Simplification of the internal market between client and provider units, rationalising financial reporting and the implementation of a performance management culture;
- Introduction of new technology for automated call handling;
- Strategic outsourcing; and
- Merger savings and synergies with EDF are yet to be realised.

Faults and interruptions

Fault costs have marginally increased year on year. This is due to the effect of an aging population of assets resulting in an increased number of faults and increases in cable repair costs occasioned by the New Road and Street Works Act for signing and guarding and traffic control required in ground works.

SPN have sought to manage this cost by:

- review of cable laying contract to identify and derive efficiencies;
- managing tree cutting;
- increasing remote control and sectionalising the network; and
- HV network shrouding.

SPN's network was affected by storms in each of the years and by severe and widespread flooding in October 2000. The 2000 and 2001 storms were covered by insurance minimising the financial impact, whilst the October 2002 storms fell below the insurance excess, following increases therein driven by high premiums. SPN has made negligible Guaranteed Standard of Performance compensation payments and the level of ex-gratia compensation payments has declined significantly from a high of £0.4m.

SPN expects that the IIP 2004/05 network performance targets will be achieved.

The number and duration of interruptions have fallen despite an increase in the number of faults. This indicates that the company has become better at restoring supply and has achieved cost savings.

Asset Management

- A company reorganisation has removed management layers and simplified the internal market interface;
- System wide Reliability Centred Maintenance ('RCM') programme has been applied to plant at all voltages to determine maintenance requirements. Improved network performance has resulted;

- The cessation of trip testing on certain circuit breaker types and the adoption of a duty based regime for tap-changer maintenance yielded significant annual R&M cost savings;

- Condition Based Maintenance practices are used to determine the trend in asset condition. Asset condition reports are a significant input to the asset refurbishment or asset replacement decision-making process;

- Investment requirements are scored and prioritised against business objectives in mitigation of five main areas of risk following which the investment plan is optimised to ensure that the business objectives are met at lowest cost; and

- Probabilistic risk assessments are carried out to inform System Wide RCM. The assessments result in decisions to improve assets and operation, to mitigate the consequences of failures or to reduce or refocus Opex or Capex.

Capex

Over the three-year period reviewed SPN has under spent the DPCR3 allowance. This over expenditure has arisen as a consequence of activity within the Non-Load Related category.

Load Expenditure Variance

Expenditure on reinforcement is attributed to:

- Insufficient headroom in parts of the network to meet load growth;

- Increased pressure to underground particular engineering options as opposed to overhead line solutions;

- Better forecasting techniques and higher asset utilisation;

- New connection activity has increased at a higher rate than forecast particularly in the non-domestic sectors; and

- Customer driven rephasing and timing change has acted to limit the overall level of over expenditure in this activity.

Non Load Related Expenditure Variance

SPN consider that the reduced expenditure is due to:

- Improvements in condition assessment;

- The adoption of alternative design options and project re-scoping;

- Work has been deferred where RCM studies have indicated that it is safe and efficient to do so;

- Asset replacement issues relating to safety for a number of specific asset types have contributed to over expenditure in that particular area; this has limited the overall level of under expenditure identified;

- Expenditure on diversion activity is higher than anticipated; this has acted to constrain the overall level of under expenditure; and

- There has been additional expenditure in metering recertification.

Other Reported Efficiency Gains

SPN have reported that savings have been achieved through:

- Revised technical specifications have enhanced supplier choice;

- Improved project management skills has constrained project overrun and enhanced project returns; and

- Standardisation of design and specification of plant and equipment enabling framework contracts to be let supporting common design approaches.

6. *United Utilities Electricity (UUE)*

The following tables and comments contain an analysis of UUE's operating and capital expenditure.

Summary financial information

DNO name: United Utilities Electricity		nominal prices	**2000/01**	**2001/02**	**2002/03**
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	527	562
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	52	45	39
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		14	14	15
Fault costs capitalised	£m		8	12	16
Total fault costs	£m		22	26	31
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	3	3	2
Metering		(6)			
Revenue (MAP & MOP)	£m		14	7	7
Operating costs: MAP	£m		2	1	1
MOP	£m		3	5	5
Depreciation	£m		4	5	6
	£m		9	10	11
Capital expenditure	£m		10	12	7
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	24
New connections					
Capital expenditure	£m		34	36	35
Customer contributions	£m		(19)	(21)	(15)
Net expenditure	£m		15	15	20

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

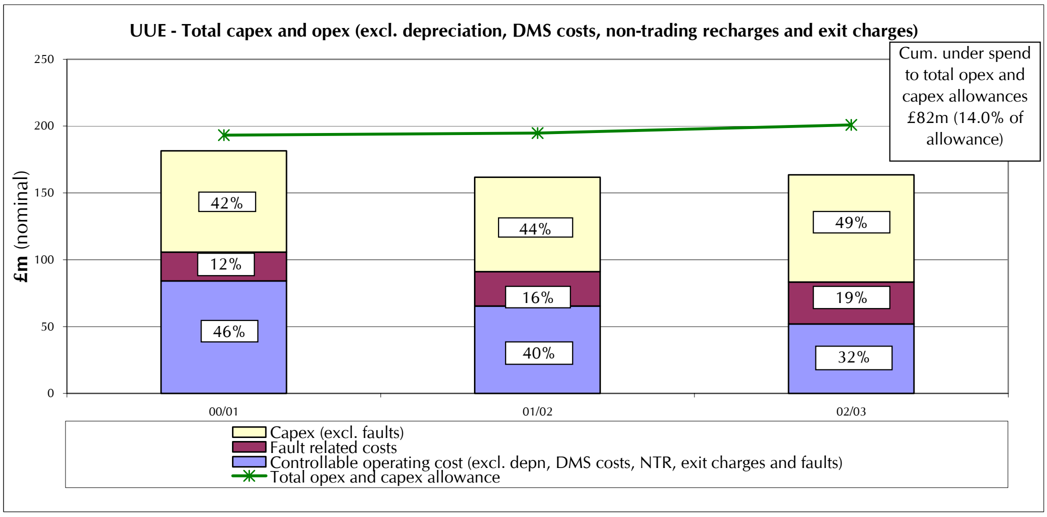
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, UUE has under spent their allowance in total for opex and capex by £82m. A high-level account of the factors which influenced these levels of costs and UUE's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in Operating Costs

The table below shows United Utilities Electricity's costs of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	17.3	16.8	16.0	14.3
Other cost of sales	13.6	12.6	21.2	36.6
Staff costs	25.8	25.9	17.6	23.4
Direct network costs	13.3	7.3	12.7	15.9
Network rates	20.2	19.9	20.1	20.1
IT costs	9.0	7.9	9.1	5.9
Statutory depreciation	46.6	48.9	46.8	48.8
Other costs	61.0	11.9	0.9	-11.0
Total	**206.8**	**151.2**	**144.4**	**154.0**

In addition to ongoing efficiencies, UUE describe some of the major factors which have affected the cost trends as follows:

- Other Costs of Sales have increased significantly in 2002 and 2003 due to an increase in multi-utility metering and connections activity;

- Pension credits are included in staff costs with particular effect in 2002;

- IT expenditure reached its peak for the period in 2002 as major development projects were implemented (see below). Costs reduced in 2003 as a result of higher capitalisation of IT expenditure; and

- Other costs in 2000 include activities that have now been transferred to the Supply business, restructuring costs, Year 2000 IT costs and corporate overheads, all of which are not included in future years, hence the significant reduction in 2001.

Cost reductions

UUE has significantly reduced its operating costs in DPCR3 and is below the allowance. This has been achieved by a variety of cost reductions, the main ones being:

- Creation of the Service Delivery organisation in October 2000 bringing together the licensed businesses of electricity distribution and water;

- Further rationalisation of the Service Delivery organisation in 2002 to create a single function responsible for construction, maintenance and operation of the network; and

- Adoption of best practices and sharing support services across electricity and water.

Rationalisation and productivity improvements

United Utilities describe their efficiencies as follows:

- Reduction of operating areas from 6 to 3, reducing management and supervisory staff and rationalisation of accommodation;

- Combining operational and support activities with water to avoid duplication and maximising synergies from a multi-utility operator;

- Rationalisation and replacement of legacy systems and developing IT systems appropriate to the DNO;

- Rationalisation of telecommunications provision to improve efficiency and reduce costs;

- The transport fleet has been reduced to improve vehicle utilisation, some vehicle maintenance has been outsourced and maintenance intervals increased;

- Procurement savings have been made by joining with Scottish Power and Northern Electric (“Selectusonline”) to increase purchasing power;

- Changes in working practices, such as increasing shift working, empowerment of industrial staff etc;

- Outsourcing of civil maintenance, some fault repair work, inspections and vegetation management; and

- Stimulating a positive organisation culture change (U Can) increasing staff productivity and satisfaction.

Asset Management Changes

- The adoption of Condition Based Maintenance has resulted in extended periods between substation inspections and overhead line patrols. Switchgear maintenance intervals have been extended to 20 years for certain asset classes. Overhead lines are now refurbished on a 15-year cycle in preference to a 10-year maintenance policy;

- An asset management/service provider organisation has been developed with dedicated restoration and planned work functions;

- An Intranet based Risk Database allows risks to be identified prioritised and managed;

- An integrated risk management approach to asset management has been developed based on Health Indices and Probability of Failure Analysis. The methodology is used both to select projects for implementation and for longer term financial planning purposes;

- A decision support tool is used to optimise the investment plan. Projects assessed as being essential for licence or statutory compliance are automatically included while discretionary projects are weighed against risk criteria for selection; and

- Long term asset replacement requirements will be forecast using Health Indices/Probability of failure analysis

Faults and Interruptions

Fault costs have increased due to a greater proportion of attributed costs. No severe storms over the last 3 years have been reported by UUE. The company has tried to reduce fault rates and costs by the following actions:

- The approach to faults has been to maintain fault rate stability while investing in mitigating the effect of faults through the use of new technology;

- Increase in the use of mobile generators to reduce customer interruptions and minutes lost;

- Wider use has been made of devices for LV transient fault automatic re-closures (REZAPs). These have been supplemented by the use of intermittent fault location equipment to provide faster location/reduction of cost solutions for intermittent faults; and

- United Utilities expect to meet its 2004/05 quality of supply CI and CML IIP targets.

Capex

United Utilities (UUE) has explained the capital expenditure variance against its own Corporate Business Plan 00 (CBP00) which was set at less than the DPCR3 allowance. The explanation of saving realised has been provided at an activity level that generally maps to the capital expenditure drivers of Load and Non-Load Related Expenditure.

Load related expenditure variance

Actual expenditure for gross LRE is similar to the DPCR3 allowance. However new connections expenditure has increased due to abnormal growth in localised areas.

Non-load related expenditure variance

Actual expenditure for NLRE is lower than the DPCR3 allowance. This is primarily driven by replacement activity. However, this overall level of variance masks expenditure in metering that is higher than allowed. Making allowance for that variance effectively increases the level of under expenditure in replacement activity.

UUE has identified the following reasons for the variance:

- Foot and Mouth Disease had a net effect of under spending the capex programme in 2001/02. To a certain extent this resource slack was compensated in other activities. The capital programme lost has been partly recovered in 2002/2003;

- There has been reduced expenditure on underground cables as a consequence of fewer faults than expected; and

- Savings have arisen due to the lower than anticipated wayleave terminations and avoidance of expensive diversion requirements but additional capital expenditure due to replacement on safety related grounds has offset other savings.

Reported Efficiency Gains

Efficiency in the activity of network reinforcement has been realised through procurement savings and more economic design not envisaged at the time of DPCR3 submission. Greater customer demand has offset these efficiencies to the extent that capital expenditure in this area is slightly ahead of plan.

UUE has adopted a policy to accelerate the Quality of Supply programme in line with its strategy of meeting the IIP targets. This programme has benefited from materials purchasing efficiencies.

7. Northern Electricity Distribution Limited (NEDL)

The following tables and comments contain an analysis of NEDL's operating and capital expenditure.

Summary financial information

DNO name: Northern Electric Distribution Ltd — nominal prices			2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	273	265
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	30	35	34
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		13	5	5
Fault costs capitalised	£m		2	9	10
Total fault costs	£m		15	14	14
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	0	0	0
Metering		(6)			
Revenue (MAP & MOP)	£m		7	7	7
Operating costs: MAP	£m		0	0	0
MOP	£m		4	6	4
Depreciation	£m		4	14	3
	£m		8	20	7
Capital expenditure	£m		2	4	5
Depreciated replacement cost of metering assets	£m	(5)	[redacted]		33
New connections					
Capital expenditure	£m		34	33	32
Customer contributions	£m		(21)	(24)	(22)
Net expenditure	£m		13	9	10

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

In 2000/01 there was a high incidence of fault costs. This had a consequential impact on the maintenance programmes achieved in the year as resources were redirected.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

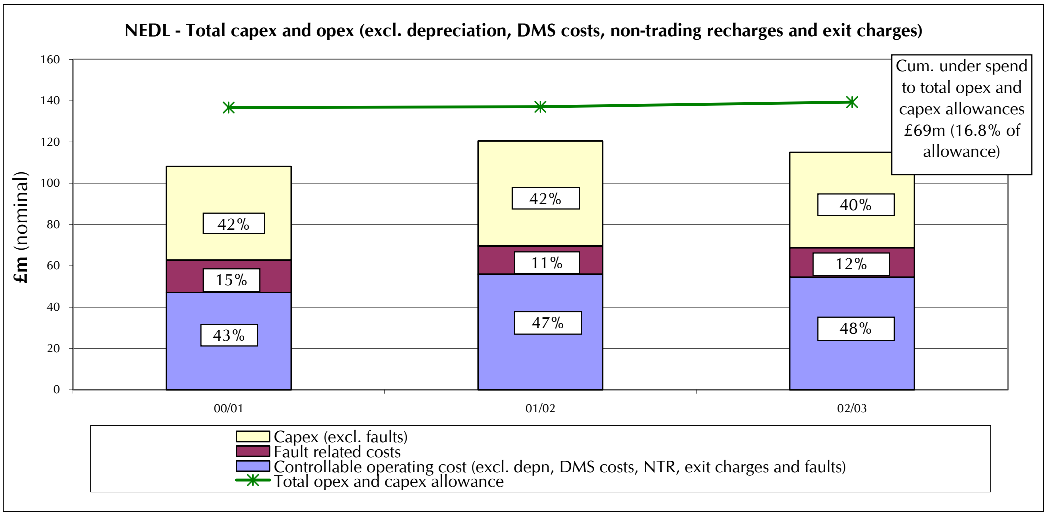
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, NEDL has under spent their allowance in total for opex and capex by £69m. A high-level account of the factors which influenced these levels of costs and NEDL's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows NEDL's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	13.8	13.5	13.1	10.9
Other cost of sales	4.4	4.6	8.0	2.0
Staff costs	4.2	12.2	15.9	12.7
Direct network costs	72.4	27.7	13.4	14.5
Network rates	15.8	15.6	15.7	15.4
IT costs	3.2	1.9	4.5	3.5
Statutory Depreciation	25.9	28.6	33.4	19.0
Other costs	6.8	6.2	10.6	15.3
Total	**146.5**	**109.4**	**114.6**	**93.3**

In addition to ongoing efficiencies and benefits from the merger with Yorkshire Electricity Distribution (YEDL) in September 2001, NEDL describe some of the major factors which have affected the cost trends as follows:

- In 2000, NEDL outsourced most of the network operations and maintenance to a related party Northern Utility Services Ltd (NUSL). As a result, internal staff costs were low and direct network costs captured the majority of the costs of operations;

- In 2001 NUSL was absorbed into the DNO thereby changing the mix of direct network and staff costs. In addition, the contract with NUSL had a significant margin which would have been captured in direct network costs. On absorbing NUSL, this margin was eliminated and a significant decrease in direct network costs was recognised;

- In 2002 depreciation increased due to harmonising policies with YEDL, resulting in the shortening of metering assets lives and extending the lives of network assets;

- Although overall costs have decreased "other" costs have increased due to separation of various costs that were previously included in other lines; and

- On the merger with YEDL in 2001 the metering activity was outsourced to Innogy.

Cost reductions

NEDL has significantly reduced operating costs since the start of DPCR3 and is outperforming the allowances through a variety of cost reductions. The main ones being:

- Efficiency initiatives implemented before the merger with YEDL, described in more detail under Rationalisation and Productivity Improvements; and

- The merger with YEDL in September 2001 created further opportunities for reductions in costs by elimination of duplication and adoption of best practices and utilisation of economies of scale. By 2003 most of the efficiencies were secured.

Rationalisation and productivity improvements

NEDL describe their efficiencies, including those from the merger, as follows:

- Forming a joint venture with other DNO's to procure goods and services in higher volumes at lower prices;

- Outsourcing of services, including Metering;

- NEDL reduced their operating regions from 3 to 2, and subsequently moved to a functional model from a geographic model. This has also enabled a reduction in infrastructure costs and depot closures;

- Flexible working arrangements have been introduced for craft staff to improve productivity;

- Staff productivity has been increased by implementing performance related pay, targeting staff exits and tightening management control of absences;

- Continued ongoing benefits from staff reductions in the last two quarters of 1999/2000;

- On the merger of NEDL and YEDL best practices from each organisation have been adopted and implemented resulting in efficiency improvements for both organisations;

- Reliability centred maintenance has been implemented on a gradual basis in order to manage risk. Reduction in maintenance volumes and frequency have lead to a reduction in manpower needed to deliver the overall programme; and

- Indirect overheads have been reviewed to reduce expenditure where ever possible.

Asset management changes

NEDL have targeted asset life extension as an efficiency focus. This is aimed at developing a better understanding of the condition of their assets and key failure modes, allowing NEDL to increase efficiency through renewing assets only where necessary.

A review of maintenance practices indicates that NEDL has focused its inspection and maintenance activities on risk management principles.

- Safety inspections of substations and lines are more frequent than condition assessments and include special inspections of vulnerable sites;

- Condition inspection data is managed by hand held technology; and

- NEDL uses Reliability Centered Maintenance techniques to develop substation maintenance procedures and carries out live non-invasive oil tests on 11 kV switchgear to determine appropriate maintenance intervals. They do not adopt statistical sampling in place of periodic maintenance, since they are concerned that statistical sampling does not assist in the assurance of operational safety at those specific sites where the sampling is not undertaken.

NEDL's investment programme is based on risk management principles.

- All company risks are identified and ranked in a risk register;

- Major substations are subject to a formally defined and audited Critical Properties Unit review;

- An annual Asset Serviceability Review considers risk, condition and performance across all voltages and defines major projects and 46 work programmes;

- Each project and programme is subject to a detailed risk assessment using fault tree analysis and other decision tools as a routine part of investment appraisal;

- Post investment appraisals are used to refine programmes and update unit costs;
- Following Ofgem's Asset Risk Management Review (ARM) in 2002, NEDL has instituted the ARM uplift programme for improving its asset management processes;
- NEDL intends to adopt a system of health indexing to improve further its prioritisation of investment by integrating condition factors into its risk assessments; and
- Medium term and long term forecasts of asset replacement are based on a simple birthday replacement model to provide a transparent check on the risk assessed programme of projects. This identifies any potential life extension that is being implied by the forward plan, relative to the agreed nominal ages and also supports clear assessment of the proportion of service life extension that is being demanded, relative to the levels of investment being made as the plan progresses.

NEDL's IT systems are based on a central database which provides a common data repository for all systems. Data is managed by an internal central records update facility to ISO 9000 standards. NEDL is finalising the integration of 132 kV, 66 kV and 33 kV asset data into the central IT system.

Faults and Interruptions

Fault costs have declined from 2001 to 2003 as a result of those investments identified above. The area was affected by floods in November 2000 and snow storms in February 2001. There were some insurance recoveries in relation to the costs of the snow storm, but not in the case of floods.

NEDL concentrated its quality of supply investments on rural areas as their supplies are dependent on overhead lines which are more vulnerable to damage in severe weather than underground cables in urban areas;

Significant investments were undertaken in the areas of arc suppression coils, rural remote control, firm busbars and alternative supplies and rogue circuits; and

NEDL expects to meet its quality of supply 2004/05 IIP targets and reports that its Medium Term Performance of asset reliability is being maintained.

Capex

Load related expenditure variance

- New connections expenditure is higher than the DPCR3 allowance and this is partly offset by generation connections being lower than the allowance as schemes under consideration at the time of the DPCR3 review did not materialise; and

- Reinforcement expenditure has been contained by adopting a risk assessment approach based on instantaneous network loading data held in the Network Management System.

Non-Load related expenditure variance

Asset Replacement expenditure is in line with NEDL's DPCR3 forecast but lower than the DPCR3 allowance due to:

- A better understanding of risk exposure, asset condition and investment appraisal improvements which has led to reprioritised expenditure;

- Some of the efficiency savings in replacement expenditure have been reinvested in replacement HV switchgear and LV street pillars and improved substation security;

- Increased investment has been made in environmental programmes such as bunding of transformers at major substations to mitigate against oil leaks;
- There have also been significant savings in LV consac cable replacement due to more effective operational management of faults;

- Overhead line replacements have been reduced in favour of replacement of decayed poles and refurbishment;

- NEDL has invested in Arc Suppression Coils for substation earthing and autoreclosers and remotely controlled switches on the 11 HV rural network, which improves the quality of supply to rural customers. NEDL has not adopted remote control of switchgear in the 11 HV urban network, which would improve quality of supply figures overall but does not benefit worst served customers; and

- Metering is lower than the DPCR3 allowance mainly due to changes in national recertification policies.

Reported Efficiency Gains

A detailed record of efficiency gains exists that indicates that the out-performance comes from a combination of capacity – demand management, service life extension, application engineering, design, procurement initiatives productivity gains and reductions in overheads.

8. Yorkshire Electricity Distribution Limited (YEDL)

The following tables and comments contain an analysis of YEDL's operating and capital expenditure.

Summary financial information

DNO name: Yorkshire Electric Distribution Ltd			nominal prices		**2000/01**	**2001/02**	**2002/03**
Information for consideration in DPCR4				note			
Net Debt (excluding guarantees)			£m	(1)	[redacted]	572	562
Guarantees			£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)			£m	(2)	42	42	44
Total fault costs (excl. atypical items)				(3)			
	Fault costs expensed		£m		9	9	6
	Fault costs capitalised		£m		16	18	15
	Total fault costs		£m		25	28	22
	Line and cable fault costs in the companies estimate of the RAV		£m	(4)	0	0	0
Metering				(6)			
	Revenue (MAP & MOP)		£m		14	15	15
	Operating costs:	MAP	£m		0	0	0
		MOP	£m		8	11	10
		Depreciation	£m		15	8	9
			£m		23	19	19
	Capital expenditure		£m		6	5	9
	Depreciated replacement cost of metering assets		£m	(5)	[redacted]	[redacted]	46
New connections							
	Capital expenditure		£m		45	39	49
	Customer contributions		£m		(37)	(39)	(29)
	Net expenditure		£m		8	0	20

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

Following implementation of the Utility Act in October 2001 the non operational assets of YEDL were transferred to sister companies in the CE Electric Group. This resulted in reduced depreciation charges in YEDL but increased contractor costs. Depreciation is not included in the definition of DPCR4 controllable operating costs whereas contractor costs are.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

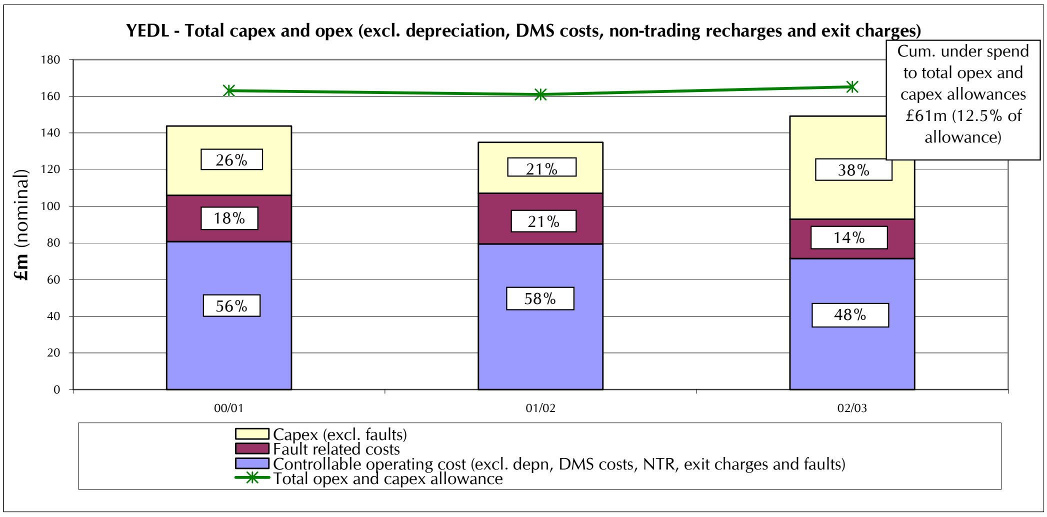
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, YEDL has under spent their allowance in total for opex and capex by £61m. A high-level account of the factors which influenced these levels of costs and YEDL's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows YEDL's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	22.4	22.3	17.3	16.1
Other cost of sales	6.1	6.1	2.7	3.8
Staff costs	34.5	21.8	9.8	1.3
Direct network costs	29.3	15.6	26.7	27.2
Network rates	23.2	23.0	23.3	22.6
IT costs	15.5	10.0	7.5	10.2
Statutory Depreciation	44.1	41.4	36.3	32.8
Other costs	8.5	9.6	22.5	16.8
Total	**183.6**	**149.8**	**146.1**	**130.8**

In addition to ongoing efficiencies and benefits from the merger with Northern Electric Distribution (NEDL) in September 2001, YEDL describe some of the major factors which have affected the cost trends as follows:

- In 2000 most of the staff of the DNO were directly employed by YEDL;
- In 2002 YEDL moved staff to Yorkshire Electricity Distribution Services Ltd (YEDSL) hence the dramatic reduction of staff costs and increase in direct network costs;

- In 2002 depreciation reduced due to the transfer of certain assets to YEDSL and in 2003 due to the reduction in the lives of network assets in order to harmonise assets lives with NEDL;
- Although overall costs have decreased "other" costs have increased due to separation of various costs that were previously included in direct network costs;
- IT costs have reduced due to efficiencies and outsourcing activities; and
- 2002 includes significant levels of severance costs arising from the merger with NEDL.

Cost reductions

YEDL has significantly reduced operating costs since the start of DPCR3 and is outperforming the allowances by a variety of cost reduction measures. The main ones being:

- Efficiency initiatives implemented before the merger with NEDL, described in more detail under Rationalisation and Productivity Improvements;
- The merger with NEDL in September 2001 created further opportunities for reductions in costs by elimination of duplication, adoption of best practices and utilisation of economies of scale. By 2003 most of the efficiencies were secured; and
- Further outsourcing services, including Metering, to 3rd party providers.

Rationalisation and productivity improvements

YEDL describe their efficiencies, including those from the merger as follows:

- Forming a joint venture with other DNOs to procure goods and services in higher volumes for lower prices;
- Outsourcing of transport services and IT in 2003;
- YEDL reduced the number of operating regions from 7 to 5. This facilitated the rationalisation of duplicated management structures, support services, and physical infrastructures (location closures);
- Post-merger, YEDL shifted to a functional operating model, resulting in further rationalisation of operational management;
- Staff productivity has been increased by implementing multi-skilling both horizontally and vertically, flexible working initiatives and tightening management control of absences;
- Reduction in staff costs have been achieved through targeted staff exits and migrating to market rate for pay;

- On the merger of NEDL and YEDL best practices from each organisation have been adopted and implemented resulting in efficiency improvements for both organisations;

- Reductions in IT cost through rationalisation of systems used by NEDL and YEDL;

- Reliability centred maintenance has been implemented on a gradual basis in order to manage risk. Reductions in maintenance volumes and frequency have lead to a reduction in manpower needed to deliver the overall programme; and

- Indirect overheads have been reviewed to reduce expenditure wherever possible.

Asset management changes

YEDL has targeted asset life extension as an efficiency focus. This is aimed at developing a better understanding of the condition of their assets and key failure modes, allowing YEDL to increase efficiency through renewing assets only where necessary.

A review of maintenance practices indicates that YEDL has focused its inspection and maintenance activities on risk management principles.

- Safety inspections of substations and lines are more frequent than condition assessments and include special inspections of vulnerable sites;

- Condition inspection data is managed by hand held technology; and

- YEDL uses Reliability Centered Maintenance techniques to develop substation maintenance procedures and carries out live non-invasive oil test on 11kV switchgear to determine appropriate maintenance intervals. It does not adopt statistical sampling in place of periodic maintenance, since it is concerned that statistical sampling does not assist in the assurance of operational safety at those specific sites where the sampling is not undertaken.

YEDL's investment programme is based on risk management principles.

- All company risks are identified and ranked in a risk register;

- Major substations are subject to a formally defined and audited Critical Properties Unit review;

- An annual Asset Serviceability Review considers risk, condition and performance across all voltages and defines major projects and 46 work programmes;

- Each project and programme is subject to a detailed risk assessment using fault tree analysis and other decision tools as a routine part of investment appraisal;

- Post investment appraisals are used to refine programmes and update unit costs;

- Following Ofgem's Asset Risk Management Review (ARM) in 2002, YEDL has instituted the ARM uplift programme for improving its asset management processes;

- YEDL intends to adopt a system of health indexing to improve further its prioritisation of investment by integrating condition factors into its risk assessments; and

- Medium term and long term forecasts of asset replacement are based on a simple birthday replacement model to provide a transparent check on the risk assessed programme of projects. This identifies any potential life extension that is being implied by the forward plan, relative to the agreed nominal ages and also supports clear assessment of the proportion of service life extension that is being demanded, relative to the levels of investment being made as the plan progresses.

YEDL's IT systems are based on a number of databases with suitable interfaces. Data is managed by an external central records update service provider to ISO 9000 standards. Following the merger YEDL is adopting the same network management system as NEDL.

Faults and Interruptions

Fault costs increased in 2002 as increased asset replacement is driven by network condition and investment is undertaken when failures occur. In 2003, levels decreased due to the benefits achieved from initiatives associated with the merger with NEDL. Floods affected the area in November 2000, but YEDL did not include the costs in the overall fault costs.

- YEDL concentrated its quality of supply investments on rural areas as their supplies are dependent on overhead lines which are more vulnerable to damage in severe weather than underground cables in urban areas;

- Significant investments were undertaken in the areas of overhead line protection, rogue circuits and small-section conductors;

- The company is also currently stepping up its programme of expanding remote control to the wider rural network; and

- YEDL expects to meet its quality of supply 2004/05 IIP targets and reports that its Medium Term Performance of asset reliability is being maintained.

Capex

Load related expenditure variance

- New connections expenditure is close to the DPCR3 allowance;
- Generation connections have increased at a rate greater than YEDL's DPCR3 forecast with a corresponding variation in income in line with a full contribution policy; and
- Reinforcement is above the DPCR3 allowance and YEDL has reinvested part of their efficiency savings in reinforcement in the EHV infrastructure and the fast growing city of Leeds.

Non-Load related expenditure variance

YEDL's actual non-load related expenditure is much lower than the DPCR3 allowance as YEDL adopted a plan that re-profiled capex from the first two years of this review into the latter three. Following the transfer of ownership in 2001, CE Electric UK, recognised the requirement to execute the increasing capital profile implied by the original plan, to ensure that risk did not begin to increase. This has resulted in a more measured, medium-risk strategy (consistent with that applied in NEDL). As a consequence, YEDL expects to increase investment in non load related expenditure in the final two years of the five-year DPCR3 price control period.

Asset Replacement expenditure is lower than the DPCR3 allowance due to:

- A better understanding of risk exposure, asset condition and investment appraisal improvements which has led to reprioritised expenditure;
- Some of the efficiency savings in replacement expenditure have been reinvested in replacement HV switchgear and LV street pillars and improved substation security;
- Increased investment has been made in environmental programmes such as bunding of transformers at major substations to mitigate against oil leaks;
- Overhead line replacements have been reduced in favour of replacement of decayed poles and refurbishment;
- YEDL has invested in Arc Suppression Coils for substation earthing and autoreclosers and remotely controlled switches on the 11 kV rural network, which improves the quality of supply to rural customers. YEDL has not adopted remote controlled switchgear in the 11 kV urban network, which would improve quality of supply figures overall but does not benefit worst served customers; and
- Metering investment is lower than the DPCR3 allowance due to the cancellation of the smart metering project arising from business separation and some increase following Ofgem's 2002 meter sampling survey.

Reported Efficiency Gains

A detailed record of efficiency gains exists that indicates that the out-performance comes from a combination of capacity – demand management, service life extension, application engineering, design, procurement initiatives, productivity gains and reductions in overheads.

9. Western Power Distribution (South Wales)

The following tables and comments contain an analysis of WPD South Wales' operating and capital expenditure.

Summary financial information

DNO name: Western Power Distribution (South Wales) nominal prices		note	2000/01	2001/02	2002/03
Information for consideration in DPCR4					
Net Debt (excluding guarantees)	£m	(1)	[redacted]	285	269
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	32	24	24
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		12	12	4
Fault costs capitalised	£m		0	0	6
Total fault costs	£m		12	12	9
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	0	0	6
Metering		(6)			
Revenue (MAP & MOP)	£m		7	7	7
Operating costs: MAP	£m		0	0	0
MOP	£m		6	4	4
Depreciation	£m		2	0	0
	£m		8	4	4
Capital expenditure	£m		0	2	3
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	36
New connections					
Capital expenditure	£m		14	17	15
Customer contributions	£m		(9)	(8)	(11)
Net expenditure	£m		6	9	4

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

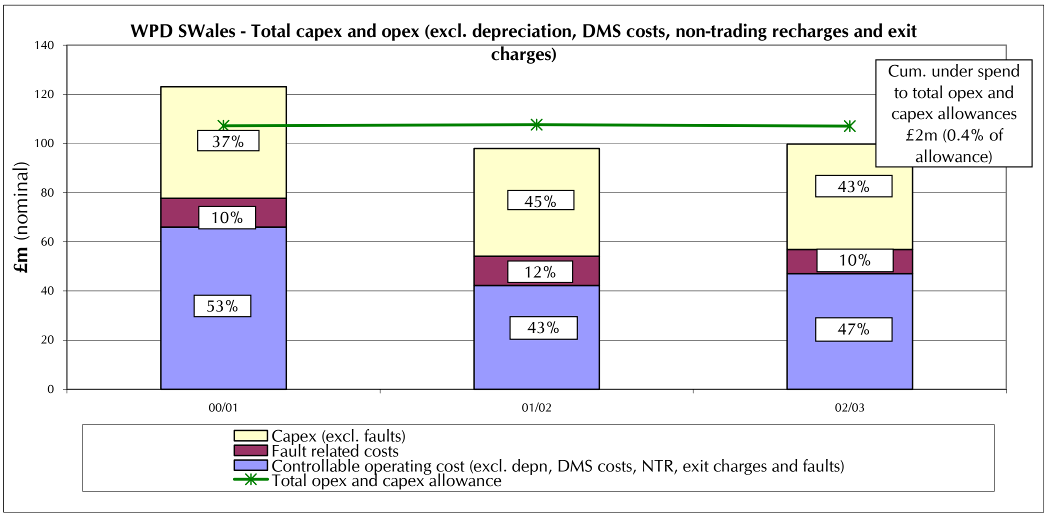
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, WPD South Wales has under spent their allowance in total for opex and capex by £2m. A high-level account of the factors which have influenced these costs and WPD South Wales' description of some of the efficiency savings made in the business since the DPCR3 review is set out below.

Trends in operating costs

The table below shows WPD South Wales' cost of sales and operated costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	10.4	9.8	9.9	9.3
Other cost of sales	3.5	3.8	3.7	5.3
Staff costs	15.0	13.4	15.7	10.9
Direct network costs	37.7	27.1	15.3	15.2
Network rates	9.4	11.2	11.7	12.2
IT costs (non-staff)	1.9	1.7	2.7	2.7
Statutory depreciation	27.8	26.5	26.2	26.9
Other costs	67.5	22.2	5.1	6.0
Total	**173.2**	**115.7**	**90.3**	**88.5**

In addition to ongoing efficiencies, WPD South Wales describe some of the major factors which have affected the cost trends as follows:

- During 99/00, when under Hyder's ownership, a programme of reorganisation was undertaken which lead to headcount reductions. All headcount reductions were achieved by means of voluntary redundancy for which a charge was made in the year to meet these costs;

- The billing system was written down in 99/00 as it became clear that it did not work. The written down billing system costs amounted to a substantial proportion of the other costs in 99/00;

- Following the acquisition by WPD South West, certain WPD South Wales' IT system costs were written down in 00/01. These systems became redundant when WPD South West's existing IT systems were introduced in WPD South Wales;

- One-off restructuring and redundancy costs were incurred in 00/01 and 01/02 as a result of the acquisition by WPD South West;

- Synergies have arisen as a result of the acquisition by WPD South West leading to cost savings; and

- Tree cutting costs in 01/02 and 02/03 are higher than in previous years due to embarking on a programme to rectify a backlog in tree trimming which had built up prior to the acquisition by WPD South West. Inspection costs were also higher reflecting additional inspection work on lines and poles.

Cost reductions

WPD South Wales has reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, WPD's explanations for this level of outperformance are set out below.

In general, operating cost reductions have been generated by:

- Synergies arising from the integration of South Wales Electricity, acquired in September 2000 as part of Hyder plc. Hyder plc also included Welsh Water which was subsequently sold to Glas Cymru;
- Adoption across the group of best practices from each of the two Distribution Businesses;
- Stand-alone rationalisations and productivity improvements not related to the merger with South Wales Electricity (now know as WPD South Wales); and
- Development of asset management policies and practices.

Rationalisation and productivity improvements

In addition to a reduction in head office costs and other costs allocated to the businesses, WPD South Wales described their efficiencies as follows:

- A culture of reducing controllable operating costs while delivering improved customer service and network performance;

- Adoption of best practices from WPD South West;

- In-house provision of a customer contact centre has lead to reduced costs while improving the service to the end customer;

- Team structures have been developed such that responsibility is delegated to the lowest operating level and team members are encouraged to implement changes to their work that either improve customer service or reduce costs. This team structure has, among other things, reduced the number of middle management and increased productivity;

- Flexible, innovative working practices and multi-skilling have led to higher output for craftsmen;

- Significant savings have been made in procurement through consolidation of procurement, stores and use of internet reverse auctions;

- Maintenance of vehicles out of normal operational hours has maximised the number available at any one time for operational usage;

- Common IT systems have been adopted which have delivered increased efficiency and reduced maintenance and licence costs; and

- Increasing investment has taken place on many circuits that have suffered most from faults, with the intention of restricting the numbers of customers affected. Consequently an increasing number of faults can be restored centrally from the control centre without the need to contact standby staff.

Asset management changes

- Improved diagnostic and inspection techniques has enabled the life of assets to be maximised without being changed unnecessarily;

- WPD South Wales and WPD South West operate under a single executive hierarchical organisation structure. Contrary to the trend in most other DNOs, WPD does not operate an asset owner / asset operator management structure;

- WPD manage their assets via a strong suite of policy documentation in the form of parent directives, policies, standard techniques, safety bulletins and equipment specifications, with clear accountabilities assigned;

- Policy rules for asset management are directly translated into practice through the company asset data management system, CROWN, which allows policy changes to be rapidly and comprehensively applied to all relevant activities;

- WPD inspects overhead lines using a time based regime immediately remedying identified defects. In addition, poorly performing HV overhead circuits are prioritised for refurbishment;

- In the short term, WPD evaluates the asset risk using health indices to target replacement of assets. Risk is assessed from condition of the asset, weighting of the importance of the condition (health indices) and analysis of fault history for circuits;

- In the medium to long term, asset replacement modelling is based on asset ages and replacement profiles in which expected lives are formulated taking risk into consideration;

- WPD uses Reliability Centred Maintenance (RCM) techniques for substation maintenance procedures and incorporates risk assessment within the RCM studies; and

- WPD's investment decisions are based on risk management principles and alternatives are ranked by net present value (NPV) over a 40 year horizon.

Faults and interruptions

Fault cost have decreased year on year. However, interpretation of this by performing a simple trend analysis on the total fault costs would be misleading as prior to April 2002 WPD's systems did not identify replacement capital expenditure incurred in fault situations.

The operating area suffered an exceptional storm in October 2002 which disrupted services. Capital expenditure incurred to rectify the resulting faults was approximately 12% of the total identified capitalised faults during the period 1 April 2000 to 31 March 2003. No insurance pay-out was received in respect of these fault costs.

WPD South Wales reports that it would appear to be on course to meet its quality of supply IIP targets for 2004/2005.

Capex

The actual expenditure levels in the first three years (2000/2003) of the present price control indicate minor overspends in respect of both load and non-load related expenditures when compared to the amounts allowed by Ofgem.

Load related expenditure (LRE) variance

WPD South Wales' actual gross LRE is overspent against the DPCR3 allowances. WPD South Wales explain the variances as follows:

- New business activity particularly in respect of housing has been higher than previously forecast;

- Expenditure on reinforcement is overspent against allowed expenditure. WPD South Wales has commented that it has been unable to manage its reinforcement expenditure down to the DPCR3 allowance, although a number of 132/33kV schemes were re-assessed and deferred. The main driver for reinforcement is compliance with the principal licence condition, (i.e. comply with ER P2/5[2]). The overspend, partly due to higher than forecast load growth, is somewhat offset by procurement efficiencies and design efficiencies; and

- Connections of new generating plant, mainly renewables, have been made incurring expenditure whereas none was provided for in the DPCR3 submission. The connection costs were fully offset by connection and DUoS charges.

Non load related expenditure (NLRE) variance

WPD South Wales' actual gross NLRE is overspent against the DPCR3 allowances. WPD South Wales explain the variances as follows:

- Overspend on asset replacement. Most of the overspend has been incurred in overhead lines, although there are also modest overspends on switchgear and cables. WPD South Wales now has a policy of replacement of defective poles as and when identified in order to reduce interruptions, in line with the policy of WPD South West. This increase in pole replacement, particularly in 2002/3, has contributed to the marked improvement in WPD South Wales' interruption performance;

- Underspend against quality of supply targets which are being achieved;

- Underspend in respect of (non-rechargeable) diversions; and

- Overspend on meters due to a policy change whereby meters are now changed in the year prior to the year in which they would be out of certification instead of during the year in question. This change brings WPD South Wales into line with WPD South West.

Reported Efficiency Gains

WPD South Wales have reported efficiency gains from procurement initiatives and lower cost designs.

[2] Energy Networks Association: Engineering Recommendation P2/5, Security of Supply.

10. Western Power Distribution (South West)

The following tables and comments contain an analysis of WPD South West's operating and capital expenditure.

Summary financial information

DNO name: Western Power Distribution (South West) nominal prices		note	2000/01	2001/02	2002/03
Information for consideration in DPCR4					
Net Debt (excluding guarantees)	£m	(1)	[redacted]	338	415
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	29	22	28
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		19	15	8
Fault costs capitalised	£m		0	0	14
Total fault costs	£m		19	15	22
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	0	0	16
Metering		(6)			
Revenue (MAP & MOP)	£m		11	11	11
Operating costs: MAP	£m		0	0	0
MOP	£m		3	6	6
Depreciation	£m		2	3	3
	£m		5	8	8
Capital expenditure	£m		4	4	4
Depreciated replacement cost of metering assets	£m	(5)	[redacted]		47
New connections					
Capital expenditure	£m		23	24	26
Customer contributions	£m		(14)	(14)	(15)
Net expenditure	£m		9	10	11

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

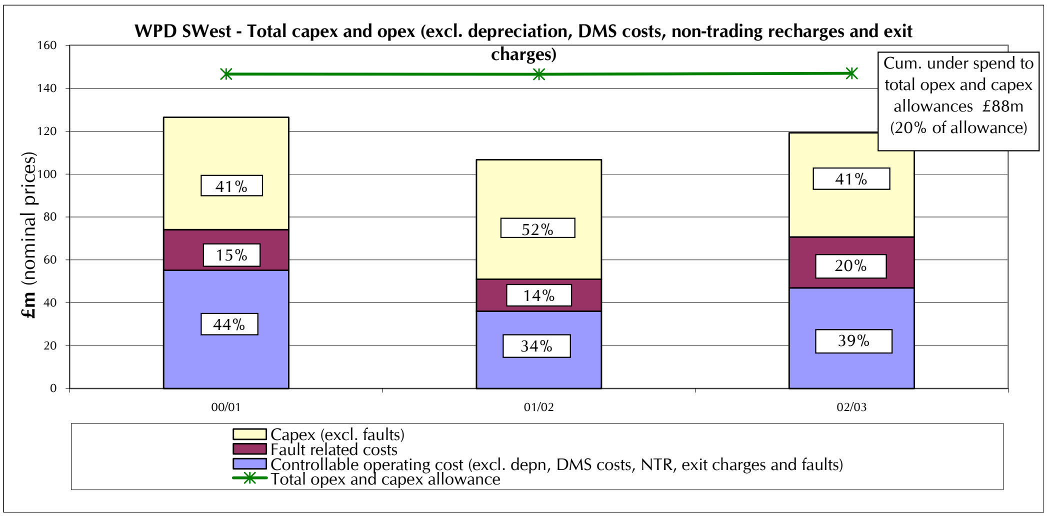
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of cost performance



In DPCR3 to date, WPD South West has under spent their allowance in total for opex and capex by £88m. A high-level account of the factors which have influenced these costs and WPD South West's description of some of the efficiency savings made in the business since the DPCR3 review is set out below.

Trends in operating costs

The table below shows WPD South West's cost of sales and operated costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	9.4	9.4	10.0	9.4
Other cost of sales	6.3	8.9	7.9	7.3
Staff costs	27.5	21.6	22.6	22.7
Direct network costs	24.0	16.4	14.4	13.8
Network rates	15.4	15.6	15.7	16.1
IT costs (non staff)	6.5	3.2	2.4	2.3
Statutory depreciation	36.1	27.9	31.6	33.1
Other costs	8.3	5.8	(10.2)	(8.9)
Total	**133.5**	**108.8**	**94.4**	**95.8**

In addition to ongoing efficiencies, WPD South West describes some of the major factors which have affected the cost trends as follows:

- Opportunity to streamline costs following the sale of WPD South West's supply business in September 1999 which made a significant contribution to the reduction in costs between 99/00 and 00/01;
- Synergies have arisen from the acquisition of South Wales Electricity (now known as WPD South Wales) in September 2000 leading to cost savings;

- Following the acquisition of South Wales Electricity, a share of the joint corporate costs and engineering overheads incurred by WPD South West are recharged to WPD South Wales. Operating costs presented in the above table are stated net of recharges to WPD South Wales with the exception of Staff costs. Staff costs are presented before the recharge to WPD South Wales. The recharge is included in the Other costs line item as a negative amount, thus contributing to the negative balance disclosed in 01/02 and 02/03; and

- A review of accruals balances by WPD South West resulted in the release of an abnormally high level of accrual releases in 01/02 and 02/03 which were not matched by costs. On the whole these accruals date to pre April 2000.

Cost reductions

WPD South West has significantly reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, WPD's explanations for this level of outperformance are set out below.

In general, operating cost reductions have been generated by:

- WPD South West was the first of the Regional Electricity Companies to fully separate its supply and distribution businesses following the sale of the SWEB supply business to London Electricity in September 1999. The process of separation was completed during 2000 and provided a major opportunity for streamlining of processes and cost reduction particularly in central overheads;

- Synergies arising from the integration of South Wales Electricity, acquired in September 2000 as part of Hyder plc. Hyder plc also included Welsh Water which was subsequently sold to Glas Cymru;

- Adoption across the group of best practices from each of the two Distribution Businesses;

- Stand-alone rationalisations and productivity improvements not related to the merger with South Wales Electricity; and

- Development of asset management policies and practices.

Rationalisation and productivity improvements

In addition to a reduction in head office costs and other costs allocated to the businesses, WPD South West described their efficiencies as follows:

- A culture of reducing controllable operating costs while delivering improved customer service and network performance;

- In-house provision of a customer contact centre has lead to reduced costs while improving the service to the end customer;

- Team structures have been developed such that responsibility is delegated to the lowest operating level and team members are encouraged to implement changes to their work that either improve customer service or reduce costs. This team structure has, among other things, reduced the number of middle management and increased productivity;

- Flexible, innovative working practices and multi-skilling have led to higher output for craftsmen;

- Significant savings have been made in procurement through consolidation of procurement, stores and use of internet reverse auctions;

- Maintenance of vehicles out of normal operational hours has maximised the number available at any one time for operational usage;

- Common IT systems have been adopted which have delivered increased efficiency and reduced maintenance and licence costs; and

- Increasing investment has taken place on many circuits that have suffered most from faults, with the intention of restricting the numbers of customers affected. Consequently an increasing number of faults can be restored centrally from the control centre without the need to contact standby staff.

Asset management changes

- Improved diagnostic and inspection techniques has enabled the life of assets to be maximised without being changed unnecessarily;

- WPD South Wales and WPD South West operate under a single executive hierarchical organisation structure. Contrary to the trend in most other DNOs, WPD does not operate an asset owner / asset operator management structure;

- WPD manage their assets via a strong suite of policy documentation in the form of parent directives, policies, standard techniques, safety bulletins and equipment specifications, with clear accountabilities assigned;

- Policy rules for asset management are directly translated into practice through the company asset data management system, CROWN, which allows policy changes to be rapidly and comprehensively applied to all relevant activities;

- WPD inspects overhead lines using a time based regime immediately remedying identified defects. In addition, poorly performing HV overhead circuits are prioritised for refurbishment;

- In the short term, WPD evaluates the asset risk using health indices to target replacement of assets. Risk is assessed from condition of the asset, weighting of the importance of the condition (health indices) and analysis of fault history for circuits;

- In the medium to long term, asset replacement modelling is based on asset ages and replacement profiles in which expected lives are formulated taking risk into consideration;

- WPD uses Reliability Centred Maintenance (RCM) techniques for substation maintenance procedures and incorporates risk assessment within the RCM studies; and

- WPD's investment decisions are based on risk management principles and alternatives are ranked by net present value (NPV) over a 40 year horizon.

Faults and interruptions

WPD South West's total fault costs decrease in 01/02 followed by an increase in 02/03. However, interpretation of this by performing a simple trend analysis on the total fault costs would be misleading as prior to April 2002 WPD's systems did not identify replacement capital expenditure incurred in fault situations.

The operating area suffered an exceptional storm in October 2002 which disrupted services. Capital expenditure incurred to rectify the resulting faults from this storm was approximately 10% of the total identified capitalised faults during the year ended 31 March 2003. No insurance pay-out was received in respect of these fault costs.

WPD South West reports that it is facing a challenge to meet both its quality of supply IIP targets for 2004/2005.

Capex

The actual expenditure levels in the first three years (2000/2003) of the present price control indicate underspends in respect of both load and non-load related expenditures when compared to the DPCR3 allowances.

Load related expenditure variance

WPD South West's actual gross LRE is underspent against the DPCR3 allowances. WPD South West explains the variances as follows:

- New business activity has been higher than previously forecast resulting in an overspend against the DPCR3 allowances; and

- Expenditure on reinforcement shows an underspend against allowed expenditure, comprising mainly reductions due to general load growth being lower than expected and deferments of major schemes due either to delays in the consents process or loads not materialising as previously forecast.

Non load related expenditure variance

WPD South West's actual gross NLRE is underspent against the DPCR3 allowances. WPD South West explains the variances as follows:

- Overspend on asset replacement. There has been appreciable overspend in underground cables at 33kV, 11kV and LV (Consac) voltage levels. This overspend has been offset by an underspend on overhead line refurbishment, variances on other asset categories being relatively small.

- Underspend on quality of supply although the 2004/5 IIP targets have yet to be met. WPD South West maintains that opportunities for further lower cost measures such as protection and automation are largely exhausted.

- Underspend in respect of (non-rechargeable) diversions.

- Overspend on metering due to re-allocation of staff costs.

Reported Efficiency Gains

WPD South West has reported efficiency gains from procurement initiatives and lower cost designs.

11. SP Manweb (SPM)

The following tables and comments contain an analysis of SPM's operating and capital expenditure.

Summary financial information

DNO name: SP Manweb nominal prices			**2000/01**	**2001/02**	**2002/03**
Information for consideration in DPCR4		note			
Net Debt/(surplus) (excluding guarantees)	£m	(1)	[redacted]	(130)	(109)
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	37	41	29
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		16	10	9
Fault costs capitalised	£m		11	13	25
Total fault costs	£m		27	24	33
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	11	14	26
Metering		(6)			
Revenue (MAP & MOP)	£m		12	12	12
Operating costs: MAP	£m		0	0	0
MOP	£m		7	6	6
Depreciation	£m		0	0	0
	£m		7	6	6
Capital expenditure	£m		4	5	6
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	15
New connections					
Capital expenditure	£m		21	26	28
Customer contributions	£m		(18)	(17)	(13)
Net expenditure	£m		3	9	16

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

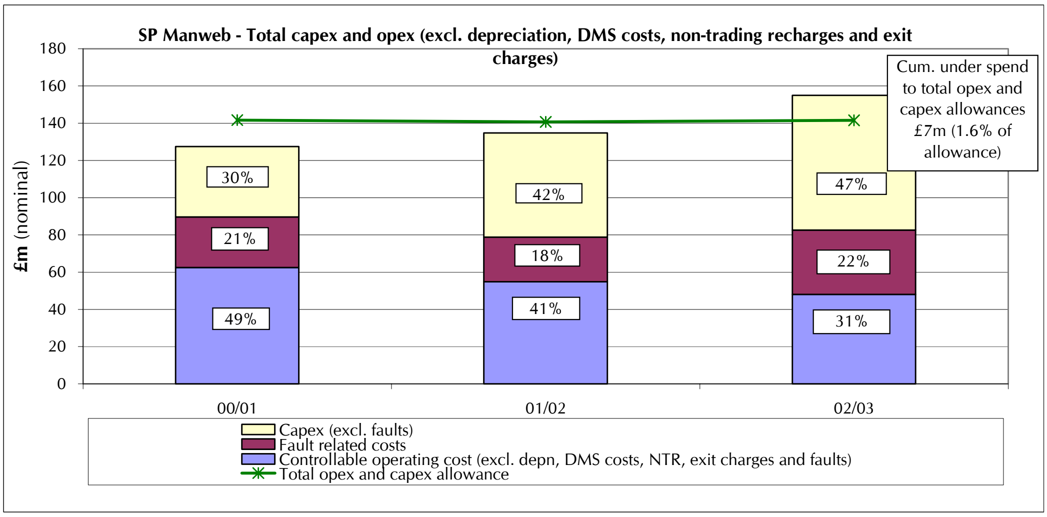
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of performance



In DPCR3 to date, SPM has under spent the combined operating costs, fault costs and capital expenditure allowances by £7m. A high-level account of the factors that have influenced total expenditure and SPM's description of some of the efficiency savings that have been made in the business since the DPCR3 review is set out below.

Trends in operating costs

The table below presents SPM's cost of sales and operating costs as reported in the Historical Business Plan Questionnaire ('HBPQ') for the last four years.

Year ending 31 March:	2000 £m	2001 £m	2002 £m	2003 £m
Transmission exit charges	17.7	17.4	15.5	15.1
Other cost of sales	10.7	16.3	8.8	7.9
Staff costs	26.9	18.7	0.2	0.5
Direct network costs	20.5	17.2	37.7	33.9
Network rates	12.9	14.4	14.5	15.5
IT costs	4.1	6.4	-	-
Statutory Depreciation	41.2	30.2	21.4	18.7
Other costs	24.1	13.6	10.0	12.7
Total	**158.1**	**134.2**	**108.1**	**104.3**

SPM's management have identified the following factors as contributing to the overall reduction in operating expenditure, both in absolute terms and as a percentage of total network expenditure and other operating costs (excluding depreciation):

- There was a major business reorganisation commencing in November 1999 and completed in October 2001 resulting in an Asset Manager – Service

Provider operating model. The adoption of this model led to the transfer of the majority of employees and associated non-operational assets to the Service Provider (a related company – SP Power Systems);

- Synergies realised from the combination, in SP Power Systems, of the inspection & maintenance, network construction & refurbishment and support functions that were previously separately performed by SP Manweb, SP Distribution and SP Transmission;

- Realignment and rationalisation of expenditure incurred to consolidate the cost of services provided by SP Power Systems to the activities associated with operating the distribution network, namely the construction & refurbishment, and the ongoing inspection and maintenance of the distribution network;

- The transfer out of SPM to SP Power Systems of the operations that provided non-regulated non-trading rechargeable services to 3rd parties;

- The transfer out of SPM in the year ended 31 March 2000 of all assets and operating costs associated with the Supply business; and

- The Foot and Mouth epidemic that occurred in March to December 2001 that resulted in the deferment of selected inspection and maintenance activities (including tree management) until 2002/03.

Cost reductions

SPM has reduced its operating costs significantly since 1999/00. From discussions with SPM management, and a review of the information provided in the HBPQ, the reasons for the reduction can be summarised in the following categories.

Rationalisation and productivity improvements

The implementation of the Asset Manager ('SPM') – Service Provider ('SP Power Systems') operating model identified above has facilitated the reduction in operating costs. Under this operating model, SP Power Systems is responsible for the planning and effective delivery of network investment and maintenance requirements to SP Manweb, SP Distribution and SP Transmission. The key rationalisation and productivity improvements delivered by this operating structure include:

- a staff reduction of approximately 450 FTE across the Asset Manager – Service Provider group when compared to pre-reorganisation staffing levels;

- rationalisation of the business structure to centralise core business functions such as Finance, Estates management etc;

- the standardisation of maintenance, operational & safety procedures and practices across SP Manweb, SP Distribution and SP Transmission thereby facilitating the efficient allocation of resources as and when required;

- the improved alignment and allocation of employees by function leading to enhanced employee productivity and utilisation;
- the realisation of economies of scale savings in procurement by consolidating regional service providers to SP Power Systems service providers; and
- a new costing methodology, resulting in the primary SP Power Systems deliverables (i.e. maintenance, inspection and network construction services) reflecting the full costs of providing such services (i.e. including administration and support costs). A by-product of adopting this methodology has been a net reallocation of costs from operating expenditure to fault and capital expenditure.

Asset management changes

The trading relationship between SPM and SP Power Systems is governed by a Service Level Agreement ('SLA'). Embedded within this SLA are targets and key performance indicators (KPI's) that are discussed and agreed on an annual basis between SPM and SP Power Systems. The asset management function within SP Power Systems has a number of additional SLA's with service providers covering:

- Operations;
- Connections;
- Maintenance;
- Network investment; and
- Risk and safety.

SP Power Systems also has SLA's with service partners covering the areas of finance and human resources.

The SPM investment programme is initiated and prioritised by an iterative risk assessment and forecasting process:

- SPM develops overall strategy from key business objectives and drivers, industry benchmarks and targets.
- SP Power Systems develops options and costs to meet outline objectives that are refined by SPM and approved by an Infrastructure Board.
- SP Power Systems applies risk assessment of assets by the Asset Criticality Assessment process to identify critical assets for approval by SPM. The output is a schedule of critical assets.
- SP Power Systems applies an Asset Risk Assessment Process and uses policy development workshops to identify asset policies that are approved by SPM. This identifies specific large projects by site and generic work programmes in terms of asset types.

- SP Power Systems updates design procurement standards and procedures and produces a long term (10 year) investment plan. (Additional asset modelling is carried out by SP Power Systems to support the development of long term programmes for both load related expenditure and non load related expenditure)

- SPM refines the plan and provides investment targets and KPI's for the SLA with SP Power Systems.

- SPM and SP Power Systems liaise to produce work plans covering an annual capital plan, a rolling two-year budget and five-year work programme that are approved by the Infrastructure Board.

SPM has established a central Data Bureau in which data is managed as a central activity using systems accredited to BS 9001. There are clear responsibilities for data management and updating data records. In addition SPM have implemented a number of data cleansing projects which are intended to ensure the integrity of the data held in the Data Bureau.

Faults and interruptions

The reported expenditure incurred to restore electricity supply after a fault has been adversely affected by the following factors:

- The occurrence of storms in 2001/02 and 2002/03. This, combined with the reduction in the insurance cover available and the tightening of the associated terms and conditions, has resulted in the full cost of supply restoration work being largely borne by SPM;

- As identified previously, the amendments to the costing methodology for services performed by SP Power Systems has also contributed to an increased cost in the supply restoration work performed.

SPM expects that IIP 2004/05 targets are on track to be achieved and that abnormal storms continue to affect the distribution network but the quality of supply effects are excluded from the IIP targets.

Capex

Load related expenditure variance

- New connections investment is generally in line with the DPCR3 allowance with non-residential connection lower than expected and wind turbine generation re-phased to later in DPCR3.

- Reinforcement is in line with the DPCR3 allowance, although some major 132 kV substation projects and the reinforcement of Liverpool have been re-phased to later in DPCR3 due to the rate of development of associated new load.

Non-load related expenditure variance

- Scottish Power ('SP') reports a planned re-phasing of non-load related capital expenditure between SPD and SPM due to foot and mouth disease in SPM and the need to expedite work on cable and switchgear replacement and, overhead line improvement in the borders area in Scotland. SP indicates that it is important to consider the two licensed areas together to obtain the full picture at this stage of DPCR3. SP intends to invest in asset volumes broadly in line with its DPCR3 allowance for both companies by the end of the DPCR3.

- Asset replacement in a number of major substations has been delayed, linked to the delays in associated new load and reinforcement work.

- Expenditure on diversions is lower than the DPCR3 allowance as the level of wayleave terminations and undergrounding for safety reasons have been lower than anticipated.

- SPM's quality of supply investment is in line with the DPCR3 allowance and has been directed at its rural care tree cutting programme and improved protection and remote control in both rural and urban areas.

Reported Efficiency Gains

SPM has implemented a number of efficiency initiatives. Asset management systems have been developed further and more decision support IT tools have been developed. The "Cascade" IT system has been implemented which provides a flexible tool for optimising and phasing the investment programme. A "build and buy for less" initiative includes procurement savings and a project office approach to switchgear and overhead line asset modernisation programmes.

12. SP Distribution (SPD)

The following tables and comments contain an analysis of SPD's operating and capital expenditure.

Summary financial information

DNO name: SP Distribution nominal prices			2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	621	528
Guarantees	£m		[redacted]	2,550	2,210
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	42	39	26
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		6	4	7
Fault costs capitalised	£m		12	23	24
Total fault costs	£m		18	27	32
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	14	23	24
Metering		(6)			
Revenue (MAP & MOP)	£m		17	17	17
Operating costs: MAP	£m		0	0	0
MOP	£m		4	5	5
Depreciation	£m		0	0	0
	£m		4	5	5
Capital expenditure	£m		7	6	7
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	22
New connections					
Capital expenditure	£m		39	31	53
Customer contributions	£m		(20)	(23)	(29)
Net expenditure	£m		19	8	24

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

SP Distribution, jointly with other subsidiaries of Scottish Power UK plc, has provided guarantees to the external lenders of Scottish Power UK plc for its external debt. The guarantee presented represents the value of the external debt of Scottish Power UK plc outstanding as at 31 March.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

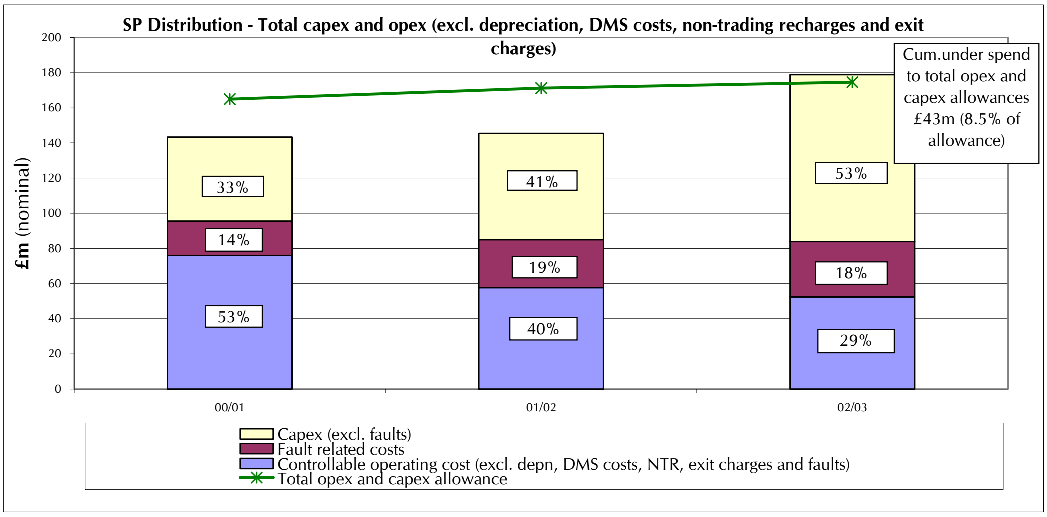
(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

Summary of performance



In DPCR3 to date, SPD has under spent the combined operating, fault and capital expenditure allowances by £43m. A high-level account of the factors that have influenced total expenditure and SPD's description of some of the efficiency savings that have been made in the business since the DPCR3 review is set out below.

Trends in operating costs

The table below presents SPD's cost of sales and operating costs as reported in the Historical Business Plan Questionnaire ('HBPQ') for the last four years.

Year ending March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	£51.7	£49.6	£50.2	£51.5
Other cost of sales	£20.9	£20.6	£8.3	£9.3
Staff costs	£34.1	£24.9	£0.2	£0.5
Direct network costs	£20.8	£14.9	£31.6	£29.8
Network rates	£15.1	£15.5	£17.5	£21.3
IT costs	£17.3	£9.8	-	-
Statutory Depreciation	£63.1	£45.4	£36.0	£30.8
Other costs	£26.1	£18.2	£14.6	£16.6
Total	**£249.1**	**£198.9**	**£158.4**	**£159.8**

SPD management have identified the following factors as contributing to the overall reduction in operating expenditure, both in absolute terms and as a percentage of total network expenditure and other operating costs (excluding depreciation):

- There was a major business reorganisation commencing in November 1999 and completed in October 2001 resulting in an Asset Manager – Service Provider operating model. The adoption of this model led to the transfer of the majority of employees and associated non-operational assets to the Service Provider (a related company – SP Power Systems);

- Synergies realised from the combination, in SP Power Systems, of inspection & maintenance, network construction & refurbishment and support functions that were previously performed separately by SP Distribution, SP Manweb and SP Transmission;

- Realignment and rationalisation of expenditure incurred to consolidate the cost of services provided by SP Power Systems to the activities associated with operating the distribution network, namely the construction & refurbishment and its ongoing inspection and maintenance;

- The transfer out of SPD to SP Power Systems of the operations that provide non-regulated non-trading rechargeable services to 3rd parties;

- The transfer out of SPD in the year ended 31 March 2000 of all assets and operating costs associated with the Supply business;

- The transfer out of SPD of the transport business that supplied vehicles and vehicle management services to the Scottish Power Group to a related group company; and

- The Foot and Mouth epidemic that occurred in March to December 2001 that resulted in the deferment of selected inspection and maintenance activities (including tree management) to 2002/03.

Cost reductions

SPD has reduced its operating costs significantly since 1999/00. From discussions with SPD management, and a review of the information provided in the HBPQ, the reasons for the reduction can be summarised in the following categories.

Rationalisation and productivity improvements

The implementation of the Asset Manager ('SPD') – Service Provider ('SP Power Systems') operating model identified above has facilitated the reduction in operating costs. Under this operating model, SP Power Systems is responsible for the planning and effective delivery of network investment and maintenance requirements to SP Distribution, SP Manweb and SP Transmission. The key rationalisation and productivity improvements delivered by this operating structure include:

- a staff reduction of approximately 450 FTE across the Asset Manager – Service Provider Group, when compared to the pre-reorganisation staffing levels;

- rationalisation of the business structure to centralise core business functions such as Finance, Estates management etc;

- the standardisation of maintenance, operational & safety procedures and practices across SP Distribution, SP Manweb and SP Transmission thereby facilitating the efficient allocation resources as and when required;

- the improved alignment and allocation of employees by function leading to enhanced productivity and utilisation;

- the realisation of economies of scale savings in procurement by consolidating regional service providers to SP Power Systems service providers; and

- a new costing methodology, resulting in the primary SP Power Systems deliverables (i.e. maintenance, inspection and network construction services) reflecting the full costs of providing such services (i.e. including administration and support costs). A by-product of adopting this methodology has been a net reallocation of costs from operating expenditure to fault and capital expenditure.

Asset management changes

The trading relationship between SPD and SP Power Systems is governed by a Service Level Agreement ('SLA'). Embedded within this SLA are targets and key performance indicators (KPI's) that are discussed and agreed on an annual basis between SPD and SP Power Systems. The asset management function within SP Power Systems has a number of additional SLA's with service providers covering:

- Operations;
- Connections;
- Maintenance;
- Network investment; and
- Risk and safety.

SP Power Systems also has SLA's with service partners covering the areas of finance and human resources.

The SPD investment programme is initiated and prioritised by an iterative risk assessment and forecasting process:

- SPD develops overall strategy from key business objectives and drivers, industry benchmarks and targets.

- SP Power Systems develops options and costs to meet outline objectives that are refined by SPD and approved by an Infrastructure Board.

- SP Power Systems applies risk assessment of assets by the Asset Criticality Assessment process to identify critical assets for approval by SPD. The output is a schedule of critical assets.

- SP Power Systems applies an Asset Risk Assessment Process and uses policy development workshops to identify asset policies that are approved by SPD. This identifies specific large projects by site and generic work programmes in terms of asset types.

- SP Power Systems updates design procurement standards and procedures and produces a long term (10 year) investment plan. (Additional asset modelling is carried out by SP Power Systems to support the development of long term programmes for both load related expenditure and non load related expenditure).

- SPD refines the plan and provides investment targets and KPI's for the contract with SP Power Systems.

- SPD and SP Power Systems liaise to produce work plans covering an annual capital plan, a rolling two-year budget and five-year work programme that are approved by the Infrastructure Board.

SPD has established a central Data Bureau in which data is managed as a central activity using systems accredited to BS 9001. There are clear responsibilities for data management and updating data records. In addition SPD have implemented a number of data cleansing projects which are intended to ensure the integrity of the data held in the Data Bureau.

Faults and interruptions

The reported expenditure incurred to restore electricity supply after a fault has been adversely affected by the following factors:

- The occurrence of storms in 2000/01 and 2001/02. This combined with the reduction in the insurance cover available and the tightening of the associated terms and conditions, has resulted in insurance recoveries not meeting the full cost of the necessary supply restoration work;

- The severity of the damaged caused by the 2000/01 storm resulted in a management decision to pay ex-gratia compensation to effected customers. This cost was recorded as operating expenditure in 2000/01; and

- As identified previously, the new costing methodology adopted for services preformed by SP Power Systems has also contributed to an increased cost in the supply restoration work performed.

SPD expects that IIP 2004/05 targets are on track to be achieved. Abnormal storms continue to affect the distribution network but the quality of supply effects are excluded from the IIP targets.

Capex

Load related expenditure variance

- Load related expenditure is higher than the DPCR3 allowance; and
- Reinforcement is higher than the DPCR3 allowance despite savings coming from a structured risk assessment approach to network reinforcement.

Non-load related expenditure variance

- Scottish Power ('SP') reports a planned re-phasing of non-load related capital expenditure between SPD and SPM due to foot and mouth disease in SPM and the need to expedite work on cable and switchgear replacement and, overhead line improvement in the borders area in Scotland. SP indicates that it is important to consider the two licensed areas together to obtain the full picture at this stage of DPCR3. SP intends to invest in asset volumes broadly in line with its DPCR3 allowance for both companies by the end of the DPCR3.
- The apparent overspend on non-load related expenditure in 2002/03 is also partly explained by SPD as being due to the removal of thresholds previously applied for capitalisation of LV fault costs.
- Following a series of storms SPD has reviewed its overhead line asset modernisation strategy and intends to rebuild light duty 11 kV overhead line interconnectors in storm-vulnerable areas at heavy duty construction. SP intends to rebuild such lines over a period of twenty years and indicates that it will require an increase in its non-load related allowance in the DPCR4 base case to achieve this programme.
- Expenditure on diversions is lower than the DPCR3 allowance as the level of wayleave terminations and undergrounding for safety reasons have been lower than anticipated.
- SPD's quality of supply investment is in line with the DPCR3 allowance and has been directed to the improvement of the borders network, its rural care tree cutting programme and use of insulated 11 kV cables which avoid tree damage and improved protection and remote control in both rural and urban areas.

Reported Efficiency Gains

SPD has implemented a number of efficiency initiatives. Asset management systems have been developed further and more decision support IT tools have been developed. The "Cascade" IT system has been implemented which provides a flexible tool for optimising and phasing the investment programme. A "build and buy for less" initiative includes procurement savings and a project office approach to switchgear and overhead line asset modernisation programmes.

13. Scottish Hydro-Electric Power Distribution (SHEPD)

The following tables and comments contain an analysis of SHEPD's operating and capital expenditure.

Summary financial information

DNO name: Scottish Hydro-Electric Power Distribution nominal prices			2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	385	334
Guarantees	£m		[redacted]	450	450
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	38	31	33
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		4	3	4
Fault costs capitalised	£m		1	2	2
Total fault costs	£m		5	5	6
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	0	0	1
Metering		(6)			
Revenue (MAP & MOP)	£m		6	6	6
Operating costs: MAP	£m		6	5	4
MOP	£m		4	2	3
Depreciation	£m		0	0	0
	£m		9	6	7
Capital expenditure	£m		6	4	5
Depreciated replacement cost of metering assets	£m	(5)	[redacted]		10
New connections		(7)			
Capital expenditure	£m				
Customer contributions	£m				
Net expenditure	£m		4	4	4

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

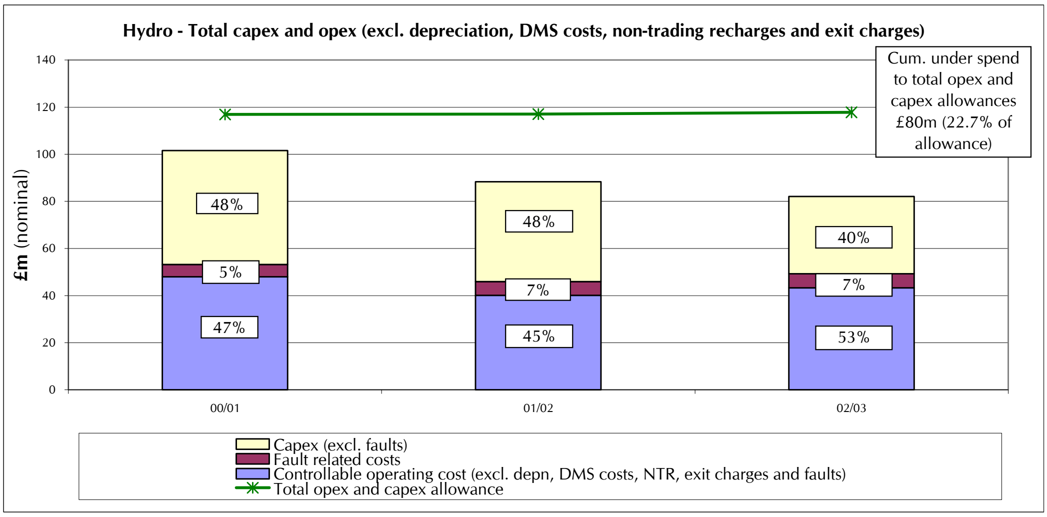
(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

(7) The company has not yet provided gross capex and customer contributions for new connections.

Summary of cost performance



In DPCR 3 to date, SHEPD has under spent its allowance in total for opex and capex by £80m. A high-level account of the factors which have influenced these costs and SHEPD's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows SHEPD's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	-	-	9.7	10.4
Other cost of sales	6.7	2.3	2.0	1.8
Staff costs	18.8	16.6	14.1	15.5
Direct network costs	9.8	8.9	8.8	9.8
Network rates	8.0	8.8	8.1	8.3
IT costs	14.9	9.4	8.2	8.1
Statutory depreciation	30.4	29.9	32.2	32.1
Other costs	8.0	6.5	2.8	4.4
Total	**96.6**	**82.4**	**85.9**	**90.4**

In addition to ongoing efficiencies, SHEPD describes some of the major factors which have affected the cost trends as follows:

- Prior to 01/02 Transmission exit charges were charged directly to customers;
- Meter reading costs are included in 99/00, in subsequent years they are classified as a Supply Business expense;

- The company adopted FRS 17 from 01/02 onwards and pension costs are higher in the last two years as a result;

- Operating costs include expenses which originate within SHEPD and also costs which are allocated/charged to SHEPD from other SSE group companies. Such costs arise in other SSE Power Systems Division companies because the business is managed on an integrated basis. Additionally, costs such as group services, IT, transport and telecommunications are charged/allocated from companies where SSE manages these functions on a group basis. The level of group costs charged/allocated to operating costs in SHEPD may vary between years depending on factors such as the activity balance between maintenance and capex (i.e. in a high capex year, more group costs will be included in capex and less in opex. Capital expenditure in 99/00 and 01/02 was higher than in 00/01 and 02/03, therefore a smaller proportion of the allocated/charged costs will be shown within operating costs); and

- In addition, 02/03 costs are higher than 01/02 because of a higher level of tree cutting; inclusion of some staff costs incorrectly charged to Supply in 01/02; and higher insurance premiums and rates (network and non-operational).

Cost reductions

SHEPD has significantly reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, SSE's explanations for this level of outperformance are set out below.

In general, operating cost reductions have been generated by:

- synergies arising from the merger with Southern Electric announced on 1 September 1998 and completed on 14 December 1998. SSE consider that the integration process was substantially complete, and that all significant merger-related savings had been made, by March 2002;

- adoption across the group of best practices from each of the two Distribution Businesses;

- stand-alone rationalisations and productivity improvements not related to the merger with Southern Electric; and

- development of asset management policies and practices.

A combination of these efficiencies has reduced headcount (FTE basis) from 00/01 to 02/03 by a figure approaching 20%.

Rationalisation and productivity improvements

In addition to a reduction in head office costs and other costs allocated to the businesses, SHEPD described efficiencies as follows.

- A culture of high pressure on cost reduction has been developed;
- The number of layers of management has halved;
- The district office network has been rationalised;
- Work groups have been functionalised to concentrate on primary work areas (such as new business, faults, programmes, meters and major projects). This also led to a reduction in the number of depots required;
- Incentive schemes, flexible and innovative working practices and multi-skilling have led to higher output for craftsmen;
- Significant savings have been made in procurement and logistics through consolidation of procurement and stores and more efficient materials-delivery practices;
- The transport fleet has been standardised across the SSE group leading to savings in initial purchase and maintenance costs;
- Common IT systems have been adopted which have delivered increased efficiency and reduced maintenance and licence costs; and
- SHEPD has factored support from Southern Electric Power Distribution into its emergency planning resourcing.

Asset management changes

The Systems Management Group (SMG) of the Power Systems Division within SSE is responsible for the management of assets and capital expenditure programme. The connections business is run as a separate ring-fenced business from the distribution business. Responsibilities for managing the assets in detail are assigned to Major Projects, Programmes, Depots (minor works), and Metering.

- SHEPD's overall approach to asset management is promulgated in the Asset Risk Management Manual, a high-level document specifying condition monitoring tools, procedures, inspection and maintenance intervals and processes for each asset category, type and voltage;
- A scoring system is used to prioritise asset replacement based on assessment of asset condition and the weighted importance of the criterion examined;
- Longer-term asset replacement modelling based on asset ages and expected lives is additionally undertaken for substation assets;
- Replacement of underground cables is determined mainly by condition;
- The lives of substation assets have been extended, based on condition assessment;

- Overhead lines with wood poles are subject to a 4-year inspection interval and refurbishment at 12-year intervals; and

- SHEPD has adopted a policy of basing its replacement investment on statistical sampling of oil in its principal HV switchgear categories.

Changes in asset management strategy in the last three years have extended the lives of these assets leading to savings in non-load related expenditure.

Faults and interruptions

Total line and cable faults costs increased in both 01/02 and 02/03. SHEPD explain this trend as follows:

- 01/02 was milder than 02/03 with lower fault numbers and costs than would have been expected otherwise;

- Before 1 October 2001 the company had insurance cover for storm damage with minimal excess. To manage its costs, as the market rate for premiums increased, the company decided to bear a greater excess and consequently no insurance recoveries have been made for storm damage since this date. SHEPD described the weather in general as being relatively benign over the last three years with none of the major storms which affected more southerly DNOs. The costs of rectification after a single day event on 28 January 2002, with abnormally high winds but no line icing were well below the insurance excess and were consequently borne by the business. Compensation payments relating to faults and interruptions have been negligible;

- SHEPD has improved its response to faults to ensure quality of supply targets and guaranteed standards are met. The introduction of mobile generation to restore supply more quickly and more frequent use of hot glove/live line techniques has led to an improvement in service but higher fault restoration costs. However, the company's investment in LV and HV fault-finding equipment should ensure more accurate location of faults leading to some savings in reinstatement costs; and

- In 02/03 external fault repair costs were higher, particularly the cost of contractors and landfill tax.

SHEPD is already meeting its quality of supply IIP targets for 04/05.

Capex

Capex in the first three years of the current price control (00/01 – 02/03) was lower than the allowances set in DPCR 3.

Load-related expenditure

Total load-related expenditure is in line with DPCR 3 allowed expenditure for 00/01 to 02/03.

- In respect of new business expenditure, SHEPD has identified an underspend due to changes in DUoS charges, efficiency savings achieved by the connections business and fewer connections than forecast; but

- SHEPD experienced more load-related expenditure over the period than it had previously anticipated.

Non-load related expenditure

Non-load related expenditure shows a significant underspend for the years 00/01 to 02/03 mainly due to reduced expenditure on asset replacement arising from changes in asset management policy.

- The year-on-year variation is mainly due to variation in HV overhead line replacement/refurbishment activity. A comparison by asset category shows appreciable underspends in respect of transformers and overhead lines compared with allowed expenditure;

- On major projects (33kV circuits and 33/11kV substations), SHEPD has deferred replacement of the original cable to Orkney and has also made efficiency savings due to design changes and procurement efficiencies. The extension of substation asset lives on condition assessment has enabled SHEPD to defer the substation asset replacement expenditure as originally included in the company's DPCR3 forecast to the level of the DPCR3 allowed expenditure;

- An appreciable underspend in expenditure on wood pole overhead lines has been achieved through the change to a 12-year cycle policy mainly of light refurbishment. The extension of HV distribution switchgear lives and maintenance intervals, through the adoption of an oil sampling technique, has also resulted in savings;

- Additional expenditure has been incurred on HV automation and protection schemes on both urban and rural circuits to improve interruption performance as measured through the weighted indices of numbers of annual interruptions and interruption duration as defined in the IIP;

- An underspend has also been obtained on minor works (HV/LV reinforcement, customer-driven network alterations), the expenditure used within depots. These savings follow the merger with SEPD and the adoption of more efficient practices; and

- SHEPD has also underspent on meters through improved bulk purchasing power following the merger, reductions in cost through technological changes and the employment of outside contractors to refurbish meters.

Reported efficiency gains

SHEPD has reported efficiency gains from:

- design changes and lower procurement prices of substation equipment;
- adopting a 12-year cycle policy mainly of light refurbishment for wood pole overhead lines;
- extension of HV distribution switchgear lives and maintenance intervals through adoption of an oil sampling technique; and
- rationalisation of minor works undertaken by depots and procurement savings on meters.

14. Southern Electric Power Distribution (SEPD)

The following tables and comments contain an analysis of SEPD's operating and capital expenditure.

Summary financial information

DNO name: Southern Electric Power Distribution	nominal prices		2000/01	2001/02	2002/03
Information for consideration in DPCR4		note			
Net Debt (excluding guarantees)	£m	(1)	[redacted]	955	865
Guarantees	£m		[redacted]	0	0
DPCR4 Controllable operating costs (excl. atypical items and faults)	£m	(2)	52	44	46
Total fault costs (excl. atypical items)		(3)			
Fault costs expensed	£m		9	10	12
Fault costs capitalised	£m		6	7	9
Total fault costs	£m		16	16	22
Line and cable fault costs in the companies estimate of the RAV	£m	(4)	0	0	0
Metering		(6)			
Revenue (MAP & MOP)	£m		18	17	17
Operating costs: MAP	£m		8	8	8
MOP	£m		8	5	6
Depreciation	£m		0	0	0
	£m		16	13	15
Capital expenditure	£m		10	8	12
Depreciated replacement cost of metering assets	£m	(5)	[redacted]	[redacted]	28
New connections		(7)			
Capital expenditure	£m				
Customer contributions	£m				
Net expenditure	£m		10	11	9

Note

(1) Net Debt has been calculated by Ofgem from information in the HBPQ and draft unaudited Regulatory Accounts. Guarantees have been extracted from the notes to the draft unaudited Regulatory Accounts and from information provided by the DNOs. Guarantees are offered by the DNOs to secure borrowings held in related parties.

(2) DPCR4 controllable operating costs – these costs have been calculated by Ofgem and exclude transmission exit charges, network rates, non-trading recharges, DMS costs, deminimis costs, Ofgem licence fees, depreciation, meter installation costs and atypical items. Atypical items are those items which are not assumed to fall within the DNO's ongoing level of operating costs and include bad debt write offs and atypical storm costs.

It should be noted that these costs are not comparable across DNOs as not all the necessary adjustments have been identified and quantified at present. It is our intention to normalise these costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, adjustments relating to accounting treatments both within and across DNOs, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

(3) Fault costs are all costs incurred as a result of a fault occurring, atypical items have been excluded. Fault costs are not comparable across DNOs as not all normalisation adjustments have been identified and quantified at present. It is our intention to normalise fault costs across all DNOs to facilitate comparison. This will include adjusting not only for atypical items but will also include, but not be limited to, overhead allocations and related party margins. These adjustments are still being considered by Ofgem.

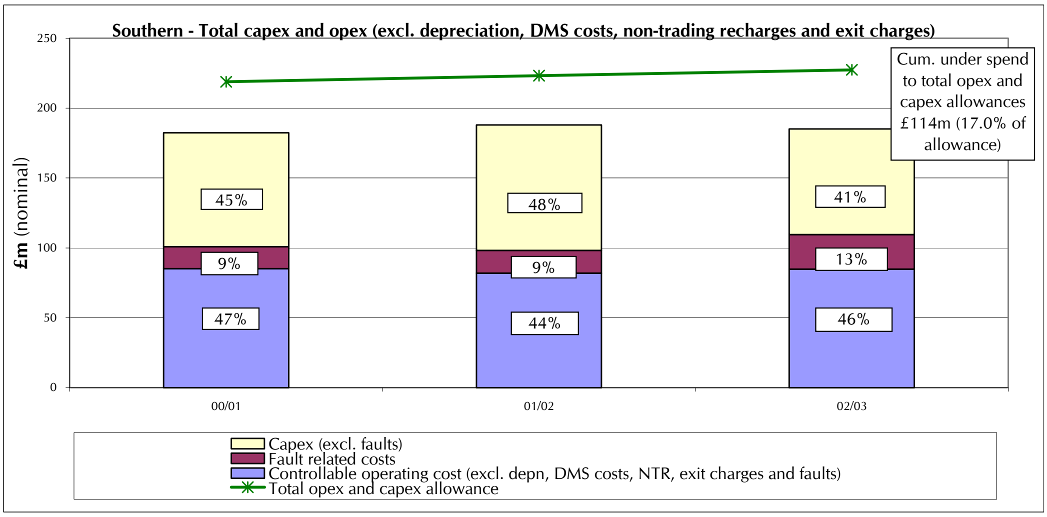
(4) This represents the line and cable fault costs that have been included in the RAV by the companies and which is the subject of consideration by Ofgem and discussed in chapter 6 of the paper.

(5) Depreciated replacement cost of metering assets are the DNO's own estimate of these numbers and these have not yet been reviewed for comparability across the DNOs.

(6) Costs shown are as included in the HBPQ and may not be comparable with other DNOs.

(7) The company has not yet provided gross capex and customer contributions for new connections.

Summary of cost performance



In DPCR 3 to date, SEPD has under spent its allowance in total for opex and capex by £114m. A high-level account of the factors which have influenced these costs and SEPD's description of some of the efficiency savings made in the business since the DPCR 3 review is set out below.

Trends in operating costs

The table below shows SEPD's cost of sales and operating costs reported in the HBPQ for the last four years.

Year ending 31 March:	**2000 £m**	**2001 £m**	**2002 £m**	**2003 £m**
Transmission exit charges	24.0	24.0	22.9	19.8
Other cost of sales	8.4	6.5	7.8	8.2
Staff costs	29.1	25.7	28.5	32.9
Direct network costs	12.4	14.0	14.3	21.0
Network rates	28.4	28.8	33.4	34.1
IT costs	25.2	15.2	13.0	9.6
Statutory depreciation	47.9	51.3	53.9	56.5
Other costs	7.8	7.6	(0.4)	(0.8)
Total	**183.2**	**173.1**	**173.4**	**181.3**

In addition to ongoing efficiencies, SEPD described some of the major factors which have affected the cost trends as follows:

- Meter reading costs are included in 99/00, in subsequent years they are classified as a Supply business expense;
- The company adopted FRS 17 from 01/02 onwards and pension costs are higher in the last two years as a result;

- Operating costs include expenses which originate within SEPD and also costs which are allocated/charged to SEPD from other SSE group companies. Such costs arise in other SSE Power Systems Division companies because the business is managed on an integrated basis. Additionally, costs such as group services, IT, transport and telecommunications are charged/allocated from companies where SSE manages these functions on a group basis. The level of group costs charged/allocated to operating costs in SEPD may vary between years depending on factors such as the activity balance between maintenance and capex (i.e. in a high capex year, more group costs will be included in capex and less in opex. Capital expenditure in 99/00 and 01/02 was higher than in 00/01 and 02/03, therefore a smaller proportion of the allocated/charged costs will be shown within operating costs); and

- In addition, 02/03 costs are higher than 01/02 because of: a higher level of tree cutting; inclusion of some staff costs incorrectly charged to Supply in 01/02; a higher general level of faults; significant one-off costs in 02/03 including uninsured storm damage and a fault repair on the Isle of Wight submarine cable; and higher insurance premiums and rates.

Cost reductions

SEPD has significantly reduced its operating costs since the DPCR 3 review and has outperformed its DPCR 3 allowances. From discussion with the company and a review of the information provided to us in the HBPQ, SSE's explanations for this level of out-performance are set out below.

In general, operating cost reductions have been generated by:

- synergies arising from the merger with Scottish Hydro-Electric plc announced on 1 September 1998 and completed on 14 December 1998. SSE consider that the integration process was substantially complete, and that all significant merger-related savings had been made, by March 2002;

- adoption across the group of best practices from each of the two Distribution Businesses;

- stand-alone rationalisations and productivity improvements not related to the merger with Scottish Hydro-Electric; and

- development of asset management policies and practices.

Rationalisation and productivity improvements

In addition to a reduction in head office costs and other costs allocated to the business, SEPD described its efficiencies as follows:

- A culture of high pressure on cost reduction has been developed;

- The number of layers of management has halved;

- Work groups have been functionalised to concentrate on primary work areas (such as new business, faults, programmes, meters and major projects). This also led to a reduction in the number of depots required;

- Incentive schemes, flexible working practices and multi-skilling have led to higher output for craftsmen;

- Significant savings have been made in procurement and logistics through consolidation of procurement and stores and more efficient materials-delivery practices;

- The transport fleet has been standardised across the SSE group leading to savings in initial purchase and maintenance costs;

- Common IT systems have been adopted which have delivered increased efficiency and reduced maintenance and license costs; and

- SEPD has factored support from Scottish Hydro-Electric Power Distribution into its emergency planning resourcing.

Asset management changes

The Systems Management Group (SMG) of the Power Systems Division within SSE is responsible for the management of assets and capital expenditure programme. The connections business is run as a separate ring-fenced business from the distribution business. Responsibilities for managing the assets in detail are assigned to Major Projects, Programmes, Depots (minor works), and Metering.

- SEPD's overall approach to asset management is promulgated in the Asset Risk Management Manual, a high-level document specifying condition monitoring tools, procedures, inspection and maintenance intervals and processes for each asset category, type and voltage;

- A scoring system is used to prioritise asset replacement based on assessment of asset condition and the weighted importance of the criterion examined;

- Longer-term asset replacement modelling based on asset ages and expected lives is additionally undertaken for substation assets;

- Replacement of underground cables is determined mainly by condition;

- The lives of substation assets have been extended, based on condition assessment;

- Overhead lines with wood poles are subject to a 4-year inspection interval and refurbishment at 12-year intervals; and

- SEPD has adopted a policy of basing its replacement investment on statistical sampling of oil in its principal HV switchgear categories.

Changes in asset management strategy in the last three measures have extended the lives of these assets leading to savings in non-load related expenditure.

Faults and interruptions

Total line and cable faults costs increased in 01/02 and significantly in 02/03. SEPD explain this trend as follows:

- Fault rates have increased by 1-2% annually over recent years and will continue to do so until 2005. The fault rate on underground cables has risen due to the Consac issue, general aging and high levels of third party damage. The fault rate on bare wire overhead lines has risen slightly, this issue is being addressed over a 12 year refurbishment cycle;

- 01/02 was milder than 02/03 with lower fault numbers and costs than would have been expected otherwise;

- Before 1 October 2001 the company had insurance cover for storm damage with minimal excess. To manage its costs as the market rate for premiums increased, the company decided to bear a greater excess and consequently no insurance recoveries have been made for storm damage since this date. Therefore the costs of the October 2002 storm were entirely borne by the company. The company's response to this storm was robust enough to ensure that compensation payments were negligible;

- There were also significant abnormal fault costs in 02/03 costs relating to a failure of the submarine cable to the Isle of Wight and the one-off write-off of the costs of old faults caused by third parties where income recovery was now considered unlikely;

- SEPD has improved its response to faults to ensure quality of supply targets and guaranteed standards are met. The introduction of mobile generation to restore supply more quickly and more frequent use of hot glove/live line techniques has led to an improvement in service but higher fault restoration costs. However, the company's investment in LV and HV fault-finding equipment should ensure more accurate location of faults leading to some savings in reinstatement costs; and

- In 02/03 external fault repair costs were higher, particularly the cost of contractors and landfill tax.

SEPD expects to meet its quality of supply IIP targets for 04/05

Capex

Capex in the first three years of the current price control (00/01 – 02/03) was lower than the allowances set in DPCR 3.

Load-related expenditure

Cumulative load-related expenditure was above the DPCR 3 allowed level of expenditure for the years 00/01 to 02/03.

- SEPD has identified an underspend in new business expenditure due to changes in DUoS charges and efficiency savings achieved by the connection business; but

- SEPD experienced more load related expenditure over the period than it had previously anticipated.

Non-load related expenditure

Non-load related expenditure shows a significant underspend for the years 00/01 to 02/03 due mainly to reduced expenditure on asset replacement arising from changes in asset management policy.

- The year-on-year variation is mainly due to variation in LV overhead line and HV and LV underground cable replacement/refurbishment activity. A comparison by asset category shows appreciable underspends in respect of transformers and overhead lines compared with allowed expenditure;

- SEPD has deferred expenditure on the replacement of underground cables as originally included in the company's DPCR3 forecast to slightly above the level of the DPCR3 allowed expenditure;

- On major projects (33kV circuits and 33/11kV substations) SEPD has deferred expenditure after risk assessment and has also made efficiency savings due to design changes and procurement efficiencies;

- An appreciable underspend in expenditure on wood pole overhead lines has been achieved through the change to a 12-year cycle policy mainly of light refurbishment and cutback in the refurbishment of HV lines to BLX-covered conductor construction. The extension of HV distribution switchgear lives and maintenance intervals, through the adoption of an oil sampling technique, also resulted in savings;

- Although there has been a reduction in expenditure on automation on HV urban circuits there has been an increase in both automation and protection expenditure on HV rural circuits to meet IIP reliability targets;

- An underspend has also been obtained on minor works (HV/LV reinforcement, customer driven network alterations). These savings follow the merger with SHEPD and the adoption of more efficient practices;

- SEPD has also underspent on meters through improved bulk purchasing power following the merger, reductions in cost through technological changes and the employment of outside contractors to refurbish meters.

Reported efficiency gains

SEPD has reported efficiency gains from:

- design changes and lower procurement prices of substation equipment;
- adopting a 12-year cycle policy mainly of light refurbishment for wood pole overhead lines;
- replacing shorter targeted lengths of LV cables instead of overlaying whole feeders;
- extension of HV distribution switchgear lives and maintenance intervals through adoption of an oil sampling technique; and
- rationalisation of minor works undertaken by depots and procurement savings on meters.

Glossary of terms

ARM	Asset risk management review
BLX	A type of insulated electrical cable covering
BPQ	Business plan questionnaire
BS	British Standard
capex	Capital expenditure
CBP	Corporate business plan
CI	Customer Interruptions
CIR	Condition importance rating
CML	Customer minutes lost
DMS	Data management services
DNO	Distribution network operator
DPCR	Distribution price control review
DPCR3	Price control in effect 1 April 2000 - 31 March 2005
DPCR4	Planned price control for 1 April 2005 - 31 March 2010
DUoS	Distribution use of system
EDF	Electricité de France
EHV	Extra high voltage (above 22kV)
EMED	East Midlands Electricity Distribution
EPN	EDF Energy Networks (EPN) plc, a DNO in the East of England
ER P2/5	Engineering recommendation P2/5, security of supply
FBPQ	Forecast business plan questionnaire
FRS	Financial reporting standard
FTE	Full time equivalent
GOSP	Guaranteed and Overall Standards of Performance
HBPQ	Historical business plan questionnaire
HE	Hydro Electric
HV	High voltage (6.6kV to 22kV)
IIP	Information and Incentives Project
IT	Information technology
IT&T	Information technology and telecoms
KPI	Key performance indicator
kV	kilovolt
LC25	Condition 25 of the standard Distribution Licence
LPN	EDF Energy Networks (LPN) plc, a DNO in London
LRE	Load related operational capital expenditure
LV	Low voltage (below 6.6kV)
MAP	Meter Asset Provider
MOp	Meter Operator
NAMP	Network asset management plan
NEDL	Northern Electricity Distribution Limited
NLRE	Non-load related operational capital expenditure
NPV	Net present value

NTR	Non-trading rechargeable
NUSL	Northern Utility Services Limited
opex	Operating expenditure
R&M	Repair and maintenance
RAV	Regulatory asset value
RCM	Reliability centred maintenance
SAP	Fully integrated management information system
SEPD	Scottish Electric Power Distribution
SHEPD	Scottish Hydro-Electric Power Distribution
SLA	Service level agreement
SMG	Group responsible for management of assets and capex program within SSE
SP	Scottish Power
SPD	Scottish Power Distribution
SPM	Scottish Power Manweb
SPN	EDF Energy Networks (SPN) plc, a DNO in the South East of England
SSE	Scottish & Southern Electricity
TXU	An American utility company, former owner of Eastern distribution network
UUE	United Utilities Electricity
WPD	Western Power Distribution
YEDL	Yorkshire Electricity Distribution Limited