Electricity Distribution Price Control Review
Initial Proposals - Allowed revenue - Cost assessment

Document type: Appendices

Ref: 94a/09

Date of publication: 3 August 2009

Deadline for response: 14 September 2009

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

Overview:

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

The current price control expires on 31 March 2010 and Ofgem is now undertaking a Distribution Price Control Review (DPCR5) to set the controls for 2010-2015. This document should be read in conjunction with our Distribution Price Control Review Initial Proposals core document. This supplementary document sets out in greater detail the associated incentives and obligations of DPCR5.

This document contains the appendices for the Cost Assessment document.

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Context

This document is one of three more detailed, technical documents that accompany the DPCR5 Initial Proposals consultation. These documents explain the methodologies and rationale we have applied in arriving at our Initial Proposals and set out further detail. They are targeted at the DNOs and those stakeholders who require an in depth understanding of our proposals in some or all areas. We are consulting separately on the treatment of the costs associated with defined benefit pension schemes.

Initial Proposals outlines our current view of the maximum allowed revenues each DNO should be allowed to collect from customers between 2010 and 2015. We set out the behaviours and outputs customers want and expect from the DNOs over this period and the incentives and obligations we propose to use to achieve them. We will publish Final Proposals in late November 2009. If the DNOs accept them, the new arrangements will come into effect on 1 April 2010. If they do not we will refer the matter to the Competition Commission.

In December 2008, we published our Policy Paper. The document focussed on three themes, environment, customers and networks and set out our views on the overall approach to setting the control, the methodologies we propose to use, the structure of incentives and the new regulatory arrangements we think are appropriate.

In May 2009, we published our Methodology and Initial Results document. This sets out details of our cost assessment methodology and the initial results for a number of core cost areas. We explained that we would continue to develop our work in this area as we worked towards Initial Proposals.

As we develop Final Proposals for late November 2009 we will continue to work closely with the RPI-X@20 team, who are considering our current approach to regulating GB's energy networks and developing recommendations for future policy. The RPI-X@20 team will publish its Emerging Thinking in November 2009.

Associated Documents

- Electricity distribution price control review. Initial Proposals - Revenue allowances - Cost assessment (94/09)
- Electricity distribution price control review. Initial Proposals. (92/09)
- Update letter of the DPCR5 process (151/08)
- Electricity distribution price control review. Initial consultation document (32/08)
- Electricity distribution price control review. Policy Paper (159/08)
- Electricity distribution price control review. Methodology and Initial Results Paper (47/09)
- Regulating energy networks for the future: RPI-X@20 Principles, Process and Issues (13/09)

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Appendix 5 – Operational Cost Assessment Further Details

Introduction

1.1. This appendix provides further details of our analysis and results to complement the data included in Chapter 4 and includes sections on the:

- benchmarking results for our core analysis and alternative regressions,
- details of the work undertaken for other statistical methods (Data Envelopment Analysis and Stochastic Frontier Analysis,
- results of the statistical testing of our analysis, and
- technical explanation of the benchmarking of adjusted operational costs.

Benchmarking Results

1.2. The benchmarking results presented in the following sections give the results per DNO for the operational costs included within the benchmarking to demonstrate the impact of changes in the drivers, cost base or methodology to the core results.

Presentation of core results

1.3. Table 1 shows the results of our 'core' benchmarking for top down, single group and groups benchmarking using the core cost drivers presented in Table 1 of this document.

Table 1 - 'Core' benchmarking results

	Top Down	Single Group	Groups	Average
CN West	106%	112%	113%	110%
CN East	85%	90%	89%	88%
ENW	112%	108%	101%	107%
CE NEDL	97%	97%	100%	98%
CE YEDL	96%	93%	92%	93%
WPD S Wales	101%	93%	98%	97%
WPD S West	102%	92%	93%	96%
EDFE LPN	100%	104%	113%	106%
EDFE SPN	109%	104%	110%	108%
EDFE EPN	112%	120%	117%	116%
SP Distribution	96%	105%	104%	102%
SP Manweb	109%	107%	111%	109%
SSE Hydro	86%	83%	90%	86%
SSE Southern	85%	82%	76%	81%

1.4. The results for the top down analysis are very different to the results of the single group and groups analysis. Our view is that the results for single group and groups are more in line with our expectation of the results given our knowledge of the DNOs. The top down analysis results are worse for ENW, WPD S Wales, WPD S West and SSE Southern. The top down analysis results are better for CN West, EDFE LPN, EDFE EPN and SP Distribution.

1.5. Our view is that the top down approach combines costs to a degree that relatively simple cost driver models are unable to identify and differentiate between the differing circumstances of the DNOs.

1.6. We have therefore used the single group and groups levels of disaggregation for our benchmarking results but have considered the impact on the results of changes in drivers and cost base at a top down level when determining our view of the comparative efficiency scores.

Alternative Drivers

1.7. We have run our analysis using alternative drivers to test the impact of using the core drivers compared to the constituent drivers individually.

Single Group

1.8. Our core analysis used a combination of direct costs and MEAV as the cost driver. We have run our analysis using MEAV as an alternative driver for the indirect costs and included the results in Table 2.

Table 2 - Single Group alternative driver comparison to Core results

	Core		Alternative Driver		Average
CN West	112%		116%		114%
CN East	90%		85%		88%
ENW	108%		104%		106%
CE NEDL	97%		96%		96%
CE YEDL	93%		89%		91%
WPD S Wales	93%		88%		91%
WPD S West	92%		88%		90%
EDFE LPN	104%		112%		108%
EDFE SPN	104%		111%		108%
EDFE EPN	120%		119%		119%
SP Distribution	105%		106%		106%
SP Manweb	107%		117%		112%
SSE Hydro	83%		83%		83%
SSE Southern	82%		81%		81%

1.9. The results of the single group analysis using MEAV as the driver of indirect costs differ most notably for SP Manweb where the results are 10 per cent worse but also for EDFE LPN and EDFE SPN where the scores are worse by 8 per cent. In each case the rankings worsen by two. The largest improvement in scores is for CN East of 6 for whom the ranking stays the same, and for ENW where the results improve by 4 per cent but the ranking improves by four.

1.10. The different results are indicative of the differences in the level of direct costs incurred by the DNOs in 2008-09 compared to the size of their network.

Groups

1.11. We have run various analysis using different drivers at a groups level. Table 3 shows the costs and different drivers we have used and shows the comparative scores for each.

Table 3 - Groups alternative drivers comparison to Core results

	CORE	Group 1	Group 1	Group 2	Group 2	Group 3	Underground Faults	Average	Average excluding UG Faults alt. driver
		Load/ Non-Load costs	MEAV	Direct Costs	MEAV	MEAV	UG Faults		
CN West	113%	113%	114%	112%	115%	113%	115%	114%	113%
CN East	89%	84%	83%	84%	89%	89%	93%	87%	86%
ENW	101%	98%	97%	98%	100%	101%	104%	100%	99%
CE NEDL	100%	100%	100%	100%	99%	100%	100%	100%	100%
CE YEDL	92%	90%	89%	90%	91%	92%	89%	90%	91%
WPD S Wales	98%	94%	94%	93%	97%	98%	97%	96%	95%
WPD S West	93%	88%	88%	88%	93%	93%	93%	91%	91%
EDFE LPN	113%	121%	121%	119%	115%	113%	112%	116%	117%
EDFE SPN	110%	114%	115%	113%	112%	110%	113%	112%	112%
EDFE EPN	117%	117%	117%	117%	117%	117%	113%	116%	117%
SP Distribution	104%	106%	106%	106%	103%	104%	101%	104%	105%
SP Manweb	111%	113%	115%	112%	115%	111%	108%	112%	113%
SSE Hydro	90%	91%	92%	91%	89%	90%	88%	90%	91%
SSE Southern	76%	79%	78%	80%	73%	76%	76%	77%	77%

1.12. The application of different drivers at a groups level makes notable changes to the comparative efficiency scores but make only small changes in the overall rankings of the DNOs except for the exclusion of the length of underground cable replaced as a driver.

1.13. The alternative drivers for Group 1 and using direct costs for Group 2 result in notably better results for CN East, WPD S Wales and WPD S West while resulting in worse results for EDFE LPN, SPN and SSE Southern.

1.14. The use of MEAV as a driver for Group 2 changes the core results to a lesser extent but is detrimental to CN West and SP Manweb.

1.15. The results when only using underground faults numbers make for more consistent results although we are concerned that the driver in this case does not take account of the majority of the costs for underground cable faults.

Change in the cost base

1.16. We have run alternative regressions on a top down basis using different costs bases in order to test the robustness of our core analysis. These alternative cost bases results from:

- Including ongoing average Non-Load costs as a proxy for the non-discretionary ongoing scale of investment,
- Excluding Property Management and IT activity costs for those areas being assessed by consultants on our behalf,
- Applying regional adjustments only to the EDFE LPN area, and
- Excluding Non-Load related cable replacement.

1.17. Table 4 shows the results of our analysis compared to the core top down approach.

Table 4 - Change in cost base comparison to Core results

	CORE	Including Non-Load Capex	Excluding Property Mgt activity	Excluding Property Mgt and IT activities	Regional Adjustment for EDFE LPN only	Excluding Non-Load cable replacement	Average
CN West	106%	107%	107%	108%	106%	112%	108%
CN East	85%	82%	86%	86%	86%	93%	86%
ENW	112%	111%	112%	107%	110%	97%	108%
CE NEDL	97%	98%	98%	102%	94%	97%	97%
CE YEDL	96%	99%	97%	101%	93%	88%	96%
WPD S Wales	101%	93%	101%	102%	99%	98%	99%
WPD S West	102%	101%	101%	105%	101%	91%	100%
EDFE LPN	100%	107%	98%	97%	105%	121%	105%
EDFE SPN	109%	111%	109%	110%	115%	114%	111%
EDFE EPN	112%	102%	112%	109%	112%	122%	111%
SP Distribution	96%	98%	96%	96%	96%	95%	96%
SP Manweb	109%	118%	110%	110%	106%	104%	109%
SSE Hydro	86%	87%	86%	81%	85%	93%	86%
SSE Southern	85%	88%	85%	85%	87%	77%	84%

1.18. The inclusion of non-load capex has a detrimental impact on the results for SP Manweb and EDFE LPN while benefiting EDFE EPN and WPD S Wales. Overall the results appear less intuitive than the core results.

1.19. The exclusions of Property Management, and then both Property Management and IT, have a consistently negative impact on the CE DNOs although at a small level. The exclusion of IT has a significantly beneficial impact on ENW and at SSE Hydro who both benefit by around 5 per cent.

1.20. The application of the regional adjustment only for LPN has a surprising impact on the overall results such that the comparative score for EDFE LPN worsened by 5 per cent but also is detrimental to the score for EDFE SPN by 6 per cent.

1.21. The exclusion of Non-Load cable replacement from the underground cable fault costs has a significant impact on the overall results with both SP DNOs benefiting by over 7 per cent, the results for ENW and the CE DNOs improving by around 3 per cent. The results worsen for the EDFE DNOs by over 5 per cent and CN East by 4 per cent. We recognise that the inclusions of cable replacement costs for determining relative efficiencies is one that we need to revisit prior to the autumn update and Final Proposals.

Alternative Method

1.22. In our core analysis Group 3 costs are the only ones to be regressed on a DNO group basis. To test the impact of this we have also run the regressions for Group 3 costs on a DNO basis.

Table 5 - Alternative method comparison to Core results

	Core		Group 3 on per DNO basis		Average
CN West	113%		113%		113%
CN East	89%		85%		87%
ENW	101%		106%		103%
CE NEDL	100%		96%		98%
CE YEDL	92%		92%		92%
WPD S Wales	98%		89%		93%
WPD S West	93%		89%		91%
EDFE LPN	113%		111%		112%
EDFE SPN	110%		109%		109%
EDFE EPN	117%		118%		117%
SP Distribution	104%		107%		105%
SP Manweb	111%		112%		112%
SSE Hydro	90%		82%		86%
SSE Southern	76%		83%		79%

1.23. The overall results for the regressions of Group 3 on a per DNO basis are surprisingly not worse for the only singleton, ENW, and improved for EDFE. However, the WPD DNOs and SSE Hydro benefit the most in the relative scores from the change in methodology. The results for SSE Southern are significantly worse.

The results for SSE suggest that their allocation of costs across their businesses is skewing their results.

Summary of regression results

1.24. Having undertaken numerous regressions using alternative drivers, cost bases and methods we have taken a pragmatic approach to combining those results into our view of the comparative efficiency of the DNOs for NOCs and Indirects.

1.25. We recognise the differences in approach across the DNOs between Network Operating Costs and Indirects and therefore have approached the results split between these two areas. Table 6 shows the final results for each DNO for NOCs and Indirects.

Table 6 - Summary regression results

	Network Operating Costs	Indirect Costs
CN West	135%	103%
CN East	101%	85%
ENW	86%	117%
CE NEDL	108%	91%
CE YEDL	111%	79%
WPD S Wales	91%	97%
WPD S West	98%	88%
EDFE LPN	91%	120%
EDFE SPN	114%	105%
EDFE EPN	107%	126%
SP Distribution	112%	98%
SP Manweb	115%	106%
SSE Hydro	59%	104%
SSE Southern	77%	79%

Data Envelopment Analysis

1.26. Table 7 comprises the DNOs' Top Down Data Envelope Analysis (DEA) and regression analysis efficient score rankings. The DEA is based on a Variable Returns to Scale (VRS) analysis for 2008-09.

Table 7 - DNOs' DEA and regression rankings for Top Down Models

DNO	Top Down Regression Ranking CORE	VRS DEA (2008-09) CORE	Difference
CN West	10	11	1
CN East	2	4	2
ENW	14	14	0
CE NEDL	6	7	1
CE YEDL	4	5	1
WPD S Wales	8	8	0
WPD S West	9	10	1
EDFE LPN	7	9	2
EDFE SPN	12	13	1
EDFE EPN	13	1	-12
SP Distribution	5	6	1
SP Manweb	11	12	1
SSE Hydro	3	1	-2
SSE Southern	1	1	0

1.27. The DEA and regression results for the core model give the same rankings for three DNOs and small differences in rankings for ten of the remaining DNOs. The ranking for EDFE EPN changes from 13 under the regression to 1 under the DEA model. The different ranking for EDFE EPN is a product of the DEA methodology whereby the DNO with the largest driver is always estimated to be on the frontier. This is a shortcoming of the DEA analysis and one of the reasons why we place more weight on the results of our regression analysis.

1.28. Our view is that the DEA analysis broadly supports the regression analysis we have undertaken and we have not adjusted our view of comparative efficiency scores as a result of running that analysis.

SFA analysis and results

1.29. We have explored the use of Stochastic Frontier Analysis (SFA), a technique similar to our regressions. A key difference is that the costs which are not explained by the cost driver - the residuals – are split into two components: an efficiency element, and a noise element which captures all other unexplained costs. Our academic advisor has conducted some analysis using this technique and further details of the findings and limitations of the approach can be found in Appendix 9. For the reasons cited in this paper we do not propose to base our DPCR5 benchmarks for operational activities upon the results from this technique.

Statistical Tests

1.30. We have conducted a series of statistical tests on the panel data models that we have estimated by ordinary least squares (OLS). These tests were selected in cooperation with our academic advisor. These tests provide an indication of the robustness of the modelling results and also indicate where some of the outputs from the regressions might be biased and require an adjustment to avoid misleading results. The tests that we have run are:

- White test for heteroscedasticity, to ensure robust inference.
- F-test for a constant cost driver coefficient over time.
- Ramsey RESET test for model mis-specification.
- Jarque-Bera test for normality.
- Standardised residuals test for outliers.

1.31. These tests including the respective hypotheses tested have been discussed in Appendix 5 of the May consultation. This appendix also discusses the implications that can be drawn from the results of these tests.

1.32. The results of these tests conducted at a 5 per cent significance level and the respective R² values for each regression are summarised in Table 8. The null hypotheses for the tests are in favour of the model's assumptions, i.e. a rejection of a test's null hypothesis suggests a finding against the model's assumptions. The table gives a test hypothesis result a "Yes" when the hypothesis is rejected and a "No" when there is not sufficient evidence to reject the hypothesis.

Table 8 - Results of statistical tests on core regressions

	Jarque-bera test				**Ramsey RESET test**	**F-test**	**White test**	**Standardised residuals**	**R^2**
	Normality test				**Model specification**	**Homogeneity test**	**Heteroscadasticity test**	**Outlier test**	**Goodness of fit**
	2005-06	2006-07	2007-08	2008-09					
DNOs LogLog Model									
TopDown	No	No	No	No	No	No	No	SPM	0.84
Sgroup	No	No	No	No	No	No	No	ENW	0.67
Group1	No	No	No	No	No	No	Yes	-	0.30
Group2	No	No	No	No	Yes	No	No	LPN	0.76
Group3	No	No	No	No	Yes	No	No	-	0.67
Overhead Faults	No	No	No	No	No	No	No	-	0.68
Underground Faults	No	No	No	No	Yes	No	Yes	SSEH	0.58
I and M	No	No	No	Yes	No	No	Yes	CNW, SSEH	0.40
Tree Curring	No	No	No	No	Yes	No	Yes	-	0.50

1.33. The following examples illustrate how these test results should be interpreted:

- For the Top Down regression, none of the tests are rejected except for the outlier test which finds SP Manweb to be an outlier.

- For the Group 3 regression, the Ramsey RESET test is failed. This suggests that there may be issues with the model's specification. We will investigate this finding further.

- For the Inspection & Maintenance (I and M) regression, the White test is rejected which suggests that model does not have a constant variance. This means that the standard errors of the coefficients in this model are biased. These standard errors are corrected using the White period robust coefficient variance estimator, which is designed to accommodate arbitrary serial correlation and time-varying variances in the disturbances. The normality test is also failed which suggests that the residuals are not normally distributed in 2008-09. In addition, CN West and SSE Hydro are found to be outliers in the model.

1.34. In addition to these tests we have also examined the results of the following tests produced as part our model estimation:

- A t-test of the statistical significance of each model's cost driver. For each of our models the drivers were found to be statistically significant at the 5 per cent significance level.

- An F-test of the statistical significance of the entire model. All of our models were found to be statistically significant at the 5 per cent significance level.

1.35. Numerical details of the test results discussed above, such as the test statistics, are available upon request.

1.36. The statistical tests discussed have helped us to develop our models and given us indications of where further analysis might be worthwhile. Overall, we think these test results support the view that our modelling is fit for purpose

Operational Costs benchmarking technical explanation

1.37. This section describes our approach to estimating the comparative efficiency scores.

1.38. Our panel data regressions have been estimated using OLS with the following:

- Cost and driver data transformed into a logarithmic basis, and
- Fixed time effects, i.e. a year specific intercept.

1.39. The equation below gives our model's functional form.

$$\log(\text{Adjusted Costs}) = a + b \times \log(\text{Driver}) + \varepsilon$$

Where a = a2005-06 in 2005-06;
a2006-07 in 2006-07
a2007-08 in 2007-08
a2008-09 in 2008-09

(a is the time specific intercept, b is the slope and ε is the residual)

1.40. The results from our regression model are used to estimate a DNO's efficient costs using the equation below.

$$\text{Efficient Adjusted Cost}_{2008-09} = \text{exponential}\left[a_{2008-09} + b \times \log(\text{Driver})\right]$$

1.41. However, as the regression was applied to logarithmic transformations of the cost data, the formula will tend to underestimate the expected costs for a given driver. We resolved this by multiplying each efficient adjusted cost values by an alpha factor. The alpha factor is calculated as the ratio of the total of original adjusted cost values across all DNOs divided by the total of efficient adjusted costs across all DNOs.

$$\alpha = \frac{\text{Total Adjusted Costs across all DNOs}}{\text{Total Efficient Adjusted Costs across all DNOs}}$$

$$\text{Corrected Efficient Adjusted Cost}_{DNO} = \text{Efficient Adjusted Cost}_{DNO} \times \alpha$$

Multiple drivers

1.42. We have used secondary drivers in our core regressions where we are of the view that it will improve the data modelling. The drivers are combined into a single 'composite' driver, as illustrated in the equation below, to allow us to use our industry knowledge to restrain the weightings between the primary and secondary drivers.

$$\text{Composite Scale Variable} = \text{Primary Driver}_1^{W_1} \times \text{Secondary Driver}_2^{W_2}$$

Where W_1 is the weight of the primary driver, and
W_2 is the weight of the secondary driver

1.43. Drivers with large values have large averages and large corresponding slope values in a multiple regression analysis. This effectively influences the respective weights that are calculated from the slope values. To eliminate this effect, the averages of both drivers were converted to zero using the following data standardisation procedure:

- We first computed the average of the driver data.
- We then computed the standard deviation for the driver data.

Finally we generated a standardised data set by subtracting the driver average from original driver data, and dividing each of the differences by the driver's standard deviation as illustrated below.

$$\text{Standardised driver data} = \frac{\text{Original driver data} - \text{Driver average}}{\text{Driver Standard deviation}}$$

1.44. The slope values for each driver were established by running a multiple regression with the adjusted cost as the dependent variable and the standardised data for the two drivers as explanatory variables. This is illustrated in the equation below where b1 and b2 are the respective slope values.

$$\text{Adjusted Cost} = \text{Intercept} + b_1 \times \text{Std. Primary Driver} + b_2 \text{ x Std. Secondary Driver} + \varepsilon$$

1.45. The calculation of the weights was based on the driver slope values (i.e. b1 and b2 in the above equation). The weights are computed as a ratio of the driver's slope value to the sum of the two drivers' slope values. For example:

$$\text{Weight for Primary Driver } (w_1) = \frac{\text{Slope value for Primary Driver } (b_1)}{\text{Sum of slope values } (b_1 + b_2)}$$

$$\text{Weight for Secondary Driver } (w_2) = \frac{\text{Slope value for Secondary Driver } (b_2)}{\text{Sum of slope values } (b_1 + b_2)}$$

1.46. With the exception of Group 3, if the computed weight for the primary driver was less than 0.5 and the corresponding weight for the secondary driver was more than 0.5, then we imposed a 0.5 weight on both the primary driver and the secondary driver. For Group 3, if the computed weight of the primary driver was less than 0.66, and the corresponding weight for the secondary driver more than 0.34, then we imposed a 0.66 weight on the primary driver and a 0.34 weight on the secondary driver.

Appendix 6 – Network Investment Further Details

1.47. This Appendix provides further details of our analysis for the following areas of core network investment:

- Demand Connections,
- General Reinforcement,
- High Value Projects,
- Asset Replacement, and
- Legal and Safety.

1.48. Also provided is further background on the following areas of non core investment:

- Discretionary expenditure,
- Major system risks (High Impact, Low Probability (HILP) only),
- BT 21st century expenditure,
- Expenditure on rising mains and laterals, and
- Expenditure on Critical National Infrastructure costs (e.g. preparation for black start and physical security).

Demand connections

1.49. As discussed in Chapter 3, we propose that only net shared use connection costs will be recovered through the price control mechanism. We think that the allowed revenues should flex according to the number of connections and, as outlined in chapter 6, larger connections should be covered by an integrated general reinforcement / large on-off connection reopener.

1.50. In the June FBPQ we asked the DNOs to split out their forecasts to allow us to understand the costs that were associated with shared use connections. In addition, to help design both the baselines and the volume driver, we needed the forecast volume and cost of connections at each voltage level.

1.51. As we have only recently received this information from the DNOs, as a modelling assumption for Initial proposals we included the DNOs forecasts unadjusted. Our initial analysis of this data and results are presented below. We will set out our Initial Proposals for these costs as part of the autumn update taking account of:

- the current and forecast economic conditions,
- the results of benchmarking average costs per connection for the categories of connections subject to the volume driver,
- scheme specific reviews of large connection schemes, and
- the analysis of the percentage of gross connection assets funded by the DNO due to the apportionment rule.

1.52. Table 1 shows that DNOs in general are forecasting a reduction in the total volume of connections (including sole use connections) and connections subject to the apportionment rule.

Table 1 - Connection volumes DPCR4 and DPCR5[1]

DNO	Total connection volume (including sole)			Total connections volume subject to the apportionment rule		
	DPCR4	DPCR5	Change	DPCR4	DPCR5	Change
CN West	79,692	69,634	-12.6%	10,298	9,001	-12.6%
CN East	111,935	104,215	-6.9%	15,871	14,773	-6.9%
ENW	65,142	51,730	-20.6%	2,424	1,967	-18.9%
CE NEDL	63,895	73,799	15.5%	17,252	17,192	-0.3%
CE YEDL	107,096	104,638	-2.3%	49,265	30,619	-37.8%
WPD S Wales	49,553	38,208	-22.9%	5,202	4,019	-22.7%
WPD S West	86,360	72,422	-16.1%	6,669	5,593	-16.1%
EDFE LPN	132,787	142,663	7.4%	215	164	-24.0%
EDFE SPN	104,671	84,236	-19.5%	500	524	5.0%
EDFE EPN	184,623	151,682	-17.8%	497	269	-46.0%
SP Distribution	35,730	37,436	4.8%		2,999	
SP Manweb	34,486	37,502	8.7%		3,041	
SSE Hydro	46,053	37,126	-19.4%	5,292	9,050	71.0%
SSE Southern	156,224	126,538	-19.0%	40,621	32,740	-19.4%
Total	1,258,247	1,131,828	-10.0%	154,105	131,950	-14.4%

1.53. Table 2 below shows that DNOs collectively forecast a 20.2 per cent and 7.9 per cent reduction in gross and net expenditure on shared use connections. However, this varies considerably across DNOs with some businesses (such as CE YEDL) forecasting very significant increases in connections expenditure.[2]

[1] SP did not provide the volume of connections subject to the apportionment rule for DPCR4.
[2] DPCR4 expenditure includes costs associated with under/over recoveries of connection charges (CN and ENW significantly under recovered for connections subject to the apportionment rule during DPCR4 which has impact on net expenditure).

Table 2 - Gross and net shared connection expenditure DPCR4 and DPCR5

DNO	Gross expenditure subject to the apportionment rule £m			Net expenditure subject to the apportionment rule £m		
	DPCR4	DPCR5	Change	DPCR4	DPCR5	Change
CN West	146.8	70.1	-52.3%	52.1	25.8	-50.5%
CN East	277.1	151.6	-45.3%	87.1	66.1	-24.2%
ENW	95.5	42.6	-55.4%	72.9	37.2	-49.0%
CE NEDL	15.5	26.0	68.0%	11.0	20.0	81.8%
CE YEDL	15.6	36.8	136.2%	9.8	28.7	192.6%
WPD S Wales	11.7	12.4	6.0%	6.0	5.4	-10.0%
WPD S West	14.1	10.7	-24.1%	10.7	7.8	-27.1%
EDFE LPN	19.1	25.5	33.5%	5.6	10.5	87.5%
EDFE SPN	75.0	97.3	29.7%	58.7	49.6	-15.5%
EDFE EPN	72.6	54.1	-25.5%	30.9	28.8	-6.8%
SP Distribution	25.0	25.2	1.1%	22.8	16.2	-29.1%
SP Manweb	43.3	46.8	8.1%	37.9	40.1	5.8%
SSE Hydro	21.0	20.4	-2.9%	16.5	16.7	1.2%
SSE Southern	35.6	72.6	103.9%	24.7	58.8	138.1%
Total	867.8	692.1	-20.2%	446.8	411.6	-7.9%

1.54. Table 3 illustrates the changes in DNO net expenditure as a proportion of gross expenditure. A number of DNOs are forecasting an increase in net expenditure as a proportion of gross (CN West, CN East, ENW, CE NEDL, CE YEDL, EDFE LPN, EDFE EPN, SSE Hydro and SSE Southern) indicating that for DPCR5 they are forecasting that a higher percentage of shared assets will be funded by the DNO

Table 3 - Net shared expenditure as a percentage of gross expenditure

DNO	Net as a proportion of Gross		
	DPCR4	DPCR5	Change
CN West	35.5%	36.8%	3.8%
CN East	31.4%	43.6%	38.6%
ENW	76.3%	87.2%	14.3%
CE NEDL	71.1%	77.0%	8.2%
CE YEDL	63.0%	78.0%	23.9%
WPD S Wales	51.3%	43.5%	-15.1%
WPD S West	75.9%	72.9%	-3.9%
EDFE LPN	29.3%	41.2%	40.4%
EDFE SPN	78.3%	51.0%	-34.9%
EDFE EPN	42.6%	53.2%	25.1%
SP Distribution	91.4%	64.1%	-29.9%
SP Manweb	87.5%	85.7%	-2.2%
SSE Hydro	78.6%	81.9%	4.2%
SSE Southern	35.5%	36.8%	3.8%
Average	51.5%	59.5%	15.5%

1.55. The volatility in the level of DNO net expenditure as a proportion of gross expenditure for some DNOs is unexpected. This would arise if DNOs are forecasting significant changes in the composition of connections provided by the DNO from DPCR4 to DPCR5. Further scrutiny of the forecast expenditure will be undertaken to develop our proposals for the autumn update.

1.56. Table 4 below shows the average cost per connection for the categories of connections subject to a volume driver.

Table 4 - Average cost per connection[3]

DNO	Average gross cost per connection £k			Average net cost per connection £k		
	Small scale LV domestic and one-off commercial	All other LV connections (with only LV work)	LV end connections involving HV work	Small scale LV domestic and one-off commercial	All other LV connections (with only LV work)	LV end connections involving HV work
CN West	21,897	1,885	6,329	4,340	392	1,371
CN East	13,399	2,602	7,538	2,154	397	1,352
ENW	5,746	21,087	26,752	5,004	17,611	20,473
CE NEDL	1,463	1,547	1,463	687	662	687
CE YEDL	1,478	1,582	1,487	662	657	670
WPD S Wales	0	1,914	2,728	0	319	652
WPD S West	0	878	1,837	0	586	408
EDFE LPN	0	0	0	0	0	0
EDFE SPN	0	0	0	0	0	0
EDFE EPN	0	0	0	0	0	0
SP Distribution	1,286	2,196	9,600	514	878	3,840
SP Manweb	1,323	1,712	4,745	529	685	1,898
SSE Hydro	2,000	1,592	2,387	800	809	857
SSE Southern	0	1,461	1,812	0	647	339
Average	1510	1737	3993	639	603	1207

1.57. A number of DNOs (CN West, CN East, ENW, SP Distribution and SP Manweb) have forecast high average connections costs in various categories. ENW has particularly high average costs per connection for the categories subject to the volume driver. A variety of reasons for the difference in average connection costs have been provided by the DNOs:

- CN state that they have included other connection types in small scale LV domestic and one-off commercial connections;
- SP indicate that the majority of their connections are done by Core Utilities Solutions Ltd and these should be included in their shared connection volumes (rather than as adopted connections i.e. connections adopted from a third party at zero cost); and
- ENW have indicated that its sampling used to forecast connection volumes may have underestimated volumes.

1.58. The issues identified with the average cost of connection will be investigated in conjunction with the DNOs before the driver values are finalised.

[3] Average excludes outliers

General reinforcement unit cost analysis

EHV and 132kV General Reinforcement

1.59. Table 5 below shows the reductions to EHV and 132kV General Reinforcement split between volume (i.e. additional capacity) and unit cost. Further details of the unit cost analysis are provided below.

Table 5 - Reductions to EHV and 132kV General Reinforcement

DNO	DPCR5 Forecast	Baseline	Reduction from DNO Forecast			Reduction from DNO Forecast		
			Unit Cost	Volume	Total	Unit Cost	Volume	Total
CN_West	128.0	107.0	8.7	12.3	21.0	6.8%	9.6%	16.4%
CN_East	160.8	132.3	10.7	17.9	28.6	6.6%	11.1%	17.8%
ENW	69.3	62.9	1.6	4.8	6.4	2.3%	7.0%	9.3%
CE_NEDL	37.1	37.1	0.0	0.0	0.0	0.0%	0.1%	0.1%
CE_YEDL	40.3	40.3	0.0	0.0	0.0	0.0%	0.0%	0.0%
WPD_S_Wales	12.6	11.0	0.0	1.6	1.6	0.0%	12.7%	12.7%
WPD_S_West	13.4	13.4	0.0	0.0	0.0	0.0%	0.0%	0.0%
EDFE_LPN	179.3	169.2	0.0	10.1	10.1	0.0%	5.6%	5.6%
EDFE_SPN	88.7	63.3	9.0	16.4	25.4	10.2%	18.5%	28.7%
EDFE_EPN	209.7	162.6	23.2	23.9	47.1	11.1%	11.4%	22.5%
SP_Distribution	38.3	38.3	0.0	0.0	0.0	0.0%	0.0%	0.0%
SP_Manweb	71.0	68.8	0.0	2.2	2.2	0.0%	3.1%	3.1%
SSE_Hydro	13.5	12.4	0.0	1.1	1.1	0.0%	8.1%	8.1%
SSE_Southern	93.8	92.4	0.0	1.4	1.4	0.0%	1.5%	1.5%
Total	1155.9	1010.9	53.2	91.9	145.1	4.6%	7.9%	12.5%

1.60. As explained in the main document, we used three different methods for assessing DNOs' unit costs for adding capacity:[4]

- a benchmark based on the ratio of forecast per MVA costs and historical per MVA cost,
- the difference between the DNOs' unit costs and the industry median (based on MEAV comparison), and
- DNO unit costs compared to the industry median using forecast new assets.

1.61. The first method was presented in the May document and is based on February 2009 FBPQ data. The model uses the DNO's volume of assets, total system MVA and our initial view on unit costs to determine a historical per MVA average cost. The ratio of the DNO's forecast per MVA costs to its historical per MVA cost is then benchmarked against the industry mean ratio.

1.62. The second method used to assess unit costs compares the DNO's unit costs against the industry median unit costs (based on an MEAV calculation, i.e. the product of the DNO's volume of assets and units costs is compared to the product of

[4] For industry average or median calculations EDFE LPN has been removed.

the DNO’s volume of assets and the industry median unit costs). This analysis was carried out using three different asset groupings:

- Substations and cables – this grouping excludes all overhead line (OHL) assets and all 66kV assets. These asset categories were removed as relatively few new overhead lines are built but the large number of high value towers has a large impact on the MEAV even for small differences in unit cost. For 66kV assets only a small number of DNOs have 66kV assets, so including these assets may lead to a biased comparison between DNOs,

- Substation – this grouping includes all 33kV and 132kV switchgear and transformer assets, and

- EHV and 132kV transformers – only includes 33kV and 132kV transformers.

1.63. The last method used for analysing unit costs involves comparing the product of the forecast new build volumes[5] (as supplied in the June FBPQ) and the DNO’s unit costs, to the product of the forecast new build volumes and the industry median unit costs.

LV and HV General Reinforcement

1.64. This section provided further details on the LV and HV benchmarking which was undertaken as a sense check of our run rate analysis. The benchmarking was not used directly in setting the baseline. The benchmarking method involved the following steps (as shown in table 6 below):

- a scaling factor is calculated based on the DNO's ratio of LV and HV MEAV[6] to the industry median LV and HV MEAV, and

- the scaling factor is then multiplied by the industry median expenditure to produce a benchmark expenditure level for each DNO.

[5] SP and SSE did not supply forecast new build volumes as part of the June FBPQ.
[6] The MEAV was calculated using the DNO's volumes and our view on direct new build unit costs.

Table 6 - Results of LV and HV Benchmarking

DNO	DPCR5 forecast £m	LV and HV MEAV £k	Scaling factor (DNO LV and HV MEAV/Median)	DPCR5 benchmark (industry median x DNO scaling factor)	Difference between the forecast and benchmark
CN_WEST	20.9	5,960,524	1.13	24.5	-3.6
CN_EAST	26.5	6,558,527	1.24	26.9	-0.4
ENW	24.2	5,792,818	1.10	23.8	0.5
CE_NEDL	19.2	3,974,921	0.75	16.3	2.9
CE_YEDL	22.4	5,579,382	1.06	22.9	-0.5
WPD_S_Wales	7.3	2,802,695	0.53	11.5	-4.2
WPD_S_West	6.9	3,880,970	0.74	15.9	-9.0
EDFE_LPN	30.5	4,297,459	0.81	17.6	12.9
EDFE_SPN	18.6	4,968,149	0.94	20.4	-1.8
EDFE_EPN	36.8	8,016,810	1.52	32.9	3.9
SP_Distribution	23.5	5,581,185	1.06	22.9	0.6
SP_Manweb	9.0	4,183,373	0.79	17.2	-8.2
SSE_Hydro	6.0	2,695,354	0.51	11.1	-5.1
SSE_Southern	56.4	7,199,622	1.37	29.5	26.9
Median	21.6	5,273,765	1.00	21.6	--

1.65. Weighting the DNO's expenditure by its relative LV and HV MEAV (compared to the industry median) takes into account the size of the DNO.

High value projects

Number of high value projects

1.66. Table 7 shows the number of high value schemes (greater than £15m in DPCR5) by DNO and the total value of those schemes. The table does not include expenditure on central London schemes, totalling approximately £170m (including schemes both greater than and less than £15m), which have been grouped together and assessed separately.

Table 7 - High value projects by DNO

Number of schemes greater than £15m per DNO		
DNO	Count	Total (£m)
CN_West	0	0
CN_East	2	46.8
ENW	2	39.1
CE_NEDL	1	30.0
CE_YEDL	1	16.9
WPD_S_Wales	0	0.0
WPD_S_West	0	0.0
EDFE_LPN	6	151.3
EDFE_SPN	1	16.4
EDFE_EPN	4	89.3
SP_Dist	0	0.0
SP_Manweb	0	0.0
SSE_Hydro	0	0.0
SSE_Southern	1	45.0
Total	**18**	**434.9**

1.67. It should be noted that the number of, and expenditure on, high value schemes varies greatly depending on the threshold used to define schemes that are considered to be high value. For example, if the threshold was reduced to £10m, there would be 41 high value schemes, with £716m of associated expenditure.

EDFE LPN

1.68. As discussed in Chapter 3, EDFE LPN have forecast expenditure of approximately £170m on a series of interrelated projects to reinforce central London. Our consultants PB Power carried out a detailed review of the proposed schemes. The overall conclusions from PB Power's report are reproduced below.

Overall Conclusions (PB Power)

1.69. "In general the EDF LPN team were very helpful and open with explanations throughout the meeting. Detailed explanations of schemes were offered and in particular quick responses were given regarding the reasoning behind discounted options indicating that options have been well considered before being dismissed.

1.70. Many of the schemes are noted to be inter-related demonstrating that a holistic approach to gain optimum benefit from the proposed work has been applied.

1.71. The majority of the reinforcement plans have been developed over a number of years and therefore originally based on a higher load growth forecast than currently envisaged for the DPCR5 period. Consequently, some of the network overloads forecast to occur during DPCR5 are now forecast to occur at a later date based on the latest load forecast which reflects the current economic downturn. However, planning stages for some of the proposed schemes have also addressed difficult practical issues and identified solutions. It was suggested that it would be inappropriate to delay some of the proposed schemes to reflect the later overload date since it was not sensible to miss the opportunities set up by the planning work already undertaken as revisiting these practical issues at a later date would probably extend the durations of the planning and construction stages.

1.72. Categorisation between asset and load related reinforcement has been based on the greatest driver. Although some of the projects reviewed had asset replacement benefits there was no apparent split in expenditure.

1.73. A number of schemes clearly have strategic drivers which are based on some of the unique factors which influence the system development in London. The strategy seems to be well developed based on experience gained over the years of extending the distribution system in this area and the timing was also supported by the progress of previous projects which have been delayed significantly due to specific issues relating to difficulties arising from the central London locations.

1.74. This review concludes that some of the proposed extra capacity and the timing of work could, on initial inspection, be considered questionable. However, when questioned further, EDF have supported their decisions based on much experience of the area, in particular the difficulties and delays encountered, resulting in a requirement to optimise the benefit to be obtained by all work undertaken. EDF stressed that "much of the planned work reviewed in this report is not yet in the detailed planning stage and anticipate timescales would be optimised during further development of the business case. Likewise investment plans would be subject to further scrutiny before capital expenditure was agreed."

Asset replacement

1.75. As discussed in chapter 3, Ofgem's baseline for asset replacement has been derived from analysis of the following cost categories:

- Modelled Volumes,
- Overhead Pole Lines,
- Substations, and
- Non Modelled Costs.

1.76. The following section provides a further breakdown of Ofgem's baseline for asset replacement into each of the four areas. For Modelled Volumes and Overhead Pole Lines reductions from the DNOs' forecasts is split between volume and unit cost reductions. A summary of the benchmarked unit costs for modelled volumes and overhead pole lines is also provided.

Modelled Volumes

1.77. An overview of Ofgem's proposed baseline for modelled asset replacement expenditure is presented in Table 8 below. In total across the industry, the baseline proposal is a 15.5 per cent reduction from the DNOs' forecasts. Of the 15.5 per cent reduction, 10.7 per cent is as a result of unit cost reductions and 4.8 per cent as a result of volume reductions. Appendix 3 provides further details at an asset specific level for each DNO.

Table 8 - Modelled asset replacement expenditure

DNO £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast			Reduction from DNO Forecast		
			Unit Cost	Volume	Total	Unit Cost	Volume	Total
CN_West	272.5	237.9	11.8	22.7	34.6	4.3%	8.3%	12.7%
CN_East	212.1	172.2	19.8	20.0	39.8	9.3%	9.4%	18.8%
ENW	238.9	203.8	18.4	16.7	35.1	7.7%	7.0%	14.7%
CE_NEDL	197.8	162.3	31.6	4.0	35.5	16.0%	2.0%	18.0%
CE_YEDL	247.7	197.7	44.4	5.6	50.0	17.9%	2.3%	20.2%
WPD_S_Wales	71.9	68.1	3.8	0.0	3.8	5.3%	0.0%	5.3%
WPD_S_West	119.9	112.2	7.8	0.0	7.8	6.5%	0.0%	6.5%
EDFE_LPN	185.0	123.8	58.1	3.1	61.2	31.4%	1.7%	33.1%
EDFE_SPN	195.5	172.2	23.3	0.0	23.3	11.9%	0.0%	11.9%
EDFE_EPN	155.6	131.7	19.1	4.8	23.9	12.3%	3.1%	15.4%
SP_Distribution	155.2	124.9	4.8	25.5	30.3	3.1%	16.4%	19.5%
SP_Manweb	235.9	203.5	12.3	20.1	32.4	5.2%	8.5%	13.7%
SSE_Hydro	53.8	52.5	1.3	0.0	1.3	2.4%	0.0%	2.4%
SSE_Southern	252.4	229.1	20.7	2.6	23.3	8.2%	1.0%	9.2%
Total	2594.0	2191.8	277.1	125.2	402.3	10.7%	4.8%	15.5%

Overhead Pole Lines

1.78. An overview of Ofgem's proposed baseline for expenditure on overhead pole lines is presented in Table 9 below. In total across the industry the baseline proposal is a 12.1 per cent reduction from the DNOs' forecasts. Of the 12.1 per cent total, 11.6 per cent is as a result of unit cost reductions and 0.5 per cent results from volume reductions.

Table 9 - Overhead Pole Line expenditure

DNO £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast			Reduction from DNO Forecast		
			Unit Cost	Volume	Total	Unit Cost	Volume	Total
CN_West	64.5	58.6	5.9	0.0	5.9	9.1%	0.0%	9.1%
CN_East	60.8	53.1	7.7	0.0	7.7	12.7%	0.0%	12.7%
ENW	73.1	48.8	20.4	3.9	24.3	27.9%	5.3%	33.2%
CE_NEDL	57.9	52.7	5.2	0.0	5.2	9.0%	0.0%	9.0%
CE_YEDL	56.6	49.5	7.1	0.0	7.1	12.5%	0.0%	12.5%
WPD_S_Wales	54.1	54.1	0.0	0.0	0.0	0.0%	0.0%	0.0%
WPD_S_West	78.9	78.9	0.0	0.0	0.0	0.0%	0.0%	0.0%
EDFE_LPN	[redacted]	[redacted]	0.0	0.0	[redacted]	[redacted]	[redacted]	[redacted]
EDFE_SPN	41.7	30.6	11.1	0.0	11.1	26.6%	0.0%	26.6%
EDFE_EPN	42.4	26.9	15.5	0.0	15.5	36.6%	0.0%	36.6%
SP_Distribution	78.2	74.7	3.5	0.0	3.5	4.5%	0.0%	4.5%
SP_Manweb	67.6	63.8	3.8	0.0	3.8	5.6%	0.0%	5.6%
SSE_Hydro	83.9	79.7	4.2	0.0	4.2	5.0%	0.0%	5.0%
SSE_Southern	95.9	80.9	15.0	0.0	15.0	15.6%	0.0%	15.6%
Total	855.6	752.3	99.4	3.9	103.3	11.6%	0.5%	12.1%

Substation expenditure

1.79. An overview of Ofgem's proposed baseline for expenditure on substations is presented in Table 10 below. In total across the industry, the baseline proposal is a 10.6 per cent reduction from the DNOs' forecasts.

Table 10 - Substation expenditure

DNO £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast	%
CN_West	24.6	19.1	5.5	22.4%
CN_East	7.5	7.5	0.0	0.0%
ENW	14.4	14.4	0.0	0.0%
CE_NEDL	14.0	14.0	0.0	0.0%
CE_YEDL	18.6	18.6	0.0	0.0%
WPD_S_Wales	7.0	6.8	0.2	2.6%
WPD_S_West	10.3	10.3	0.0	0.0%
EDFE_LPN	20.7	19.0	1.7	8.2%
EDFE_SPN	10.8	10.8	0.0	0.0%
EDFE_EPN	12.1	12.1	0.0	0.0%
SP_Distribution	19.1	16.6	2.5	13.2%
SP_Manweb	22.3	17.7	4.6	20.5%
SSE_Hydro	13.5	10.0	3.5	25.7%
SSE_Southern	21.0	16.0	5.0	23.7%
Total	215.9	192.9	22.9	10.6%

Non-modelled costs

1.80. An overview of Ofgem's proposed baseline for asset replacement expenditure not subject to replacement modelling is presented in Table 11 below. In total across the industry, the baseline proposal is a 14.2 per cent reduction from DNOs' forecasts.

Table 11 - Non-Modelled costs

DNO £m (07/08 prices)	DPCR5 Forecast	% of Forecast	Baseline	Reduction from DNO Forecast	%
CN_West	15.1	4.0%	12.1	3.0	19.9%
CN_East	5.0	1.8%	4.0	1.0	20.0%
ENW	23.6	6.7%	17.1	6.5	27.5%
CE_NEDL	9.5	3.4%	7.6	1.9	20.0%
CE_YEDL	7.3	2.2%	5.8	1.5	20.0%
WPD_S_Wales	0.8	0.6%	0.8	0.0	0.0%
WPD_S_West	2.6	1.2%	2.6	0.0	0.0%
EDFE_LPN	69.5	25.3%	67.3	2.2	3.1%
EDFE_SPN	38.5	13.4%	33.2	5.3	13.7%
EDFE_EPN	47.0	18.3%	37.7	9.3	19.8%
SP_Distribution	2.3	0.9%	1.8	0.5	20.0%
SP_Manweb	7.2	2.2%	5.8	1.4	20.0%
SSE_Hydro	0.0	0.0%	0.0	0.0	-
SSE_Southern	0.0	0.0%	0.0	0.0	-
Total	228.3	5.9%	195.8	32.5	14.2%

Unit Costs

1.81. Table 12 below shows the unit costs that have been used in the analysis, as described in the main document. For modelled volumes Ofgem's view is shown alongside the view of our external consultants (PB power) as well as the range provided by the DNOs. Table 13 shows Ofgem's benchmarked unit cost for Overhead Pole lines (refurbishment, rebuild and D pole replacement).

Table 12 - Modelled Unit Costs

Unit Cost for Modelled Asset Replacement - Direct Costs 07/08 Prices (£k)							
Asset	Units	Ofgem	PB Power	DNO - FBPQ Unit Cost Table			
				Average	Median	Min	Max
Services							
OHL - Service Replacement	#	0.40	0.70	0.54	0.50	0.20	0.90
OHL - Cutout Replacement	#	0.15	[redacted]	0.20	0.20	0.14	0.30
UG - Service Replacement	#	1.00	0.93	1.30	1.13	0.80	2.38
UG - Cutout Replacement	#	0.16	[redacted]	0.21	0.19	0.14	0.50
Cables							
LV Main (UG Plastic)	km	77.9	80.7	94.4	87.9	66.9	160.7
6.6/11kV UG Cable	km	89.5	82.3	86.2	73.5	63.5	185.5
20kV UG Cable	km	89.5	167.9	73.5	73.5	73.5	73.5
HV Sub Cable	km	300.0	210.1	380.9	471.4	200.0	471.4
33kV UG Cable	km	264.9	253.4	266.6	264.9	152.9	396.0
66kV UG Cable	km	300.0	455.4	762.9	444.5	300.0	1820.0
EHV Sub Cable	km	300.0	608.4	780.6	1021.0	300.0	1021.0
132kV UG Cable	km	1091.9	1031.0	1097.4	1179.5	685.0	1820.0
132 kV Sub Cable	km	2167.0	1216.8	2167.0	2167.0	2167.0	2167.0
Transformers							
6.6/11 kV Transformer (PM)	#	3.4	4.2	3.6	3.4	1.3	7.0
6.6/11 kV Transformer (GM)	#	14.0	13.3	12.9	12.7	9.3	17.0
20 kV Transformer (PM)	#	3.7	6.5	5.0	5.0	5.0	5.0
20 kV Transformer (GM)	#	12.3	16.4	12.3	12.3	12.3	12.3
33 kV Transformer (PM)	#	5.8	5.8	7.9	7.9	7.9	7.9
33 kV Transformer (GM)	#	399.8	519.6	394.2	350.0	223.8	586.0
66 kV Transformer	#	455.5	616.7	656.0	380.0	363.3	1757.3
132 kV Transformer	#	1077.9	1200.7	1149.7	1056.0	750.0	1757.0
Switchgear							
LV Pillar (ID)	#	6.4	7.5	6.6	6.4	4.4	9.9
LV Pillar (OD)	#	6.8	6.6	6.5	6.8	4.4	8.6
LV Board (WM)	#	8.4	10.6	11.7	8.4	4.4	26.2
6.6/11 kV CB (PM)	#	8.4	11.0	9.1	8.4	7.0	12.8
6.6/11 kV CB (GM) - Primary	#	58.7	31.8	48.0	50.0	21.4	68.0
6.6/11 kV CB (GM) - Secondar	#	11.7	10.4	18.4	11.2	5.7	68.0
6.6/11 kV Switch (PM)	#	4.1	7.5	3.8	4.1	1.3	6.1
6.6/11 kV Switch (GM)	#	8.2	8.9	8.4	8.2	4.5	18.4
6.6/11 kV RMU	#	12.0	13.8	13.7	12.9	10.0	21.5
20 kV CB (PM)	#	8.4	13.8	8.4	8.4	8.4	8.4
20 kV CB (GM)	#	12.2	64.4	12.0	12.0	12.0	12.0
20 kV RMU	#	12.9	16.4	14.5	14.5	14.5	14.5
33 KV CB (ID)	#	110.0	85.5	112.0	107.0	59.3	172.0
33 kV CB (OD)	#	83.7	60.2	85.9	83.7	44.2	135.0
33 kV RMU	#	259.5	31.8	249.5	259.5	189.2	300.0
66 KV CB (ID & OD)	#	313.4	382.1	400.6	239.2	77.2	1333.0
132 kV CB (ID & OD)	#	1077.9	694.0	657.8	583.6	131.1	1333.0
Overhead Lines - Reconductoring							
33kV Tower Line	km	39.1	[redacted]	52.8	39.1	29.8	118.0
66kV Tower Line	km	68.4	[redacted]	68.4	68.4	46.8	90.0
132 kV Pole Line	km	52.9	[redacted]	97.1	100.0	52.9	179.8
132 kV Tower Line	km	65.0	[redacted]	112.1	68.5	47.8	465.0
Support - Replacement							
33kV Tower	#	35.8		36.9	39.2	32.4	39.2
66kV Tower	#	68.4	88.6	65.0	65.0	65.0	65.0
132 kV Pole	#	2.6	7.7	14.3	14.3	2.6	26.0
132 kV Tower	#	108.9	108.9	184.3	161.0	86.2	298.0
Refurbisment and Fittings							
132 kV Tower Refurbishment	#	5.0	[redacted]	8.3	8.5	4.0	12.0
132 kV Fittings	#	4.5	5.1	5.6	4.5	3.0	11.0

Table 13 - Overhead Pole Lines

Unit Costs for Overhead Pole Lines - Direct Costs 07/08 Prices (£k)					
Activity	**Units**	**Poles/km**	**per Pole**	**Conductor Only**	**Total**
Reconductoring and Rebuilding					
LV Main - ABC reconductoring	km	3	0.8	11.6	14.1
LV Main - ABC Full Rebuild	km	20	0.8	11.6	28.1
HV - Reconductor	km	1.5	1.3	16.3	18.4
HV - Rebuild	km	11	1.3	16.3	31.1
33kV Pole line - Reconductor	km	0	2.0	23.8	23.8
33kV Pole Line - Rebuild	km	10	2.0	23.8	43.7
66kV Pole line - Reconductor	km	0		37.0	37.0
D Pole Replacement					
LV	#		1.4		1.4
HV	#		1.5		1.5
EHV	#		2.0		2.0

Legal and safety

1.82. In carrying out our assessment we have broken down the legal and safety building block costs by its constituent areas of work. We include further information below for areas where we are proposing a reduction to the DNOs' forecasts.

ESQCR safety clearances

1.83. Baseline allowances for ESQCR safety clearance work are shown in Table 14 below.

Table 14 - ESQCR safety clearances

ESQCR safety clearances								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	2.5	5.4	116%	4.2	1.2	0.2	1.7	69%
CN_East	2.3	3.0	32%	3.1	-0.1	-3%	0.8	36%
ENW	11.7	49.2	321%	24.6	24.6	50%	12.9	110%
CE_NEDL	1.5	3.1	107%	2.4	0.7	22%	0.9	61%
CE_YEDL	2.8	10.6	285%	6.2	4.4	42%	3.4	124%
WPD_S_Wales	1.2	7.7	538%	4.9	2.8	36%	3.7	306%
WPD_S_West	6.7	24.1	262%	15.8	8.4	35%	9.1	137%
EDFE_LPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_SPN	6.1	57.0	834%	36.7	20.3	36%	30.6	502%
EDFE_EPN	9.5	53.4	462%	29.0	24.4	46%	19.5	205%
SP_Distribution	7.6	9.0	18%	7.0	2.0	22%	-0.6	-7%
SP_Manweb	21.7	34.9	61%	26.0	8.9	25%	4.4	20%
SSE_Hydro	2.9	8.5	193%	6.9	1.6	19%	4.0	138%
SSE_Southern	1.6	3.0	88%	3.0	0.0	0%	1.4	88%
Total	**78.0**	**268.9**	**245%**	**169.8**	**99.0**	**37%**	**91.9**	**118%**

1.84. Allowances for ESQCR safety clearance work were calculated using similar benchmarking to that developed for the DPCR4 ESQCR reopener. For both horizontal and vertical clearance issues, the DNOs forecast the number of spans requiring remedial work and the required expenditure. The forecasts were given by both voltage and type of remedial work required.

1.85. We calculated a cost per span for different solutions at each voltage level for each DNO. The unit costs calculated were normalised based on each DNO's average number of services per pole. The normalised unit costs were then benchmarked to the mean.

1.86. Ofgem's proposed reductions to the DNOs' forecasts are all based on unit costs rather than volume of work, with the exception of a reduction made to ENW's forecast. This reduction applied to vertical clearance work forecast for the last two years of DPCR5, for which non-compliance is not confirmed.

ESQCR tree continuity

1.87. Baseline allowances for ESQCR tree continuity are shown table 15 below.

Table 15 - ESQCR tree continuity

ESQCR tree continuity								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	2.7	-	2.7	0.0	0.0	2.7	-
CN_East	0.0	2.2	-	2.2	0.0	0%	2.2	-
ENW	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_NEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_YEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_Wales	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_West	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_LPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_SPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_EPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
SP_Distribution	0.0	0.0	-	0.0	0.0	0%	0.0	-
SP_Manweb	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Hydro	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Southern	0.0	25.0	-	0.0	25.0	100%	0.0	-
Total	**0.0**	**29.8**	**-**	**4.8**	**25.0**	**84%**	**4.8**	**-**

1.88. CN East, CN West and SSE Southern have forecast network investment for ESQCR tree continuity. CN East and CN West have forecast a total of £4.8m, which pending further assessment has been included in their baseline. SSE Southern has forecast £25m. As a result of further questioning, SSE provided supporting information based on the installation of covered conductor to resolve safety clearance issues to climbable trees. However as adequate expenditure for safety issues has been allowed for in the ESQCR safety clearances expenditure outlined above we have not included this additional expenditure in our baseline allowance.

Site security

1.89. Baseline allowances for site security are shown in Table 16 below.

Table 16 - Site security

Site security								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	6.1	4.9	-19%	3.3	1.7	0.3	-2.9	-47%
CN_East	3.6	9.0	150%	5.5	3.6	39%	1.9	51%
ENW	0.5	4.7	864%	4.7	0.0	0%	4.2	864%
CE_NEDL	3.0	2.6	-14%	2.6	0.0	0%	-0.4	-14%
CE_YEDL	7.1	6.8	-5%	5.1	1.6	24%	-2.0	-28%
WPD_S_Wales	0.0	6.2	-	2.6	3.6	58%	2.6	-
WPD_S_West	0.0	3.8	-	3.8	0.0	0%	3.8	-
EDFE_LPN	1.3	2.5	92%	1.5	1.0	40%	0.2	15%
EDFE_SPN	2.4	3.6	50%	3.5	0.1	3%	1.1	45%
EDFE_EPN	5.0	3.6	-28%	3.6	0.0	0%	-1.4	-28%
SP_Distribution	0.1	1.5	1054%	1.5	0.0	0%	1.4	1054%
SP_Manweb	0.1	1.3	1983%	1.3	0.0	0%	1.2	1983%
SSE_Hydro	0.4	1.5	275%	1.5	0.0	0%	1.1	275%
SSE_Southern	2.7	1.5	-44%	1.5	0.0	0%	-1.2	-44%
Total	**32.3**	**53.5**	**66%**	**41.9**	**11.6**	**22%**	**9.6**	**30%**

1.90. Our baselines for site security costs were derived by benchmarking DNOs' costs relative to the number of substations with EHV or 132kV primary voltage.

Other legal and safety costs

1.91. We are not proposing any reductions to the DNOs' forecasts for expenditure on ESQCR other, asbestos clearance and safety climbing devices.

1.92. Where DNOs have identified other legal and safety costs, we have only proposed reductions to their forecasts in a limited number of areas, notably:

- We are proposing to reduce EDF's forecasts for replacement of small cross section overhead line conductor to DPCR4 levels. We have provided an allowance for overhead line conductor replacement as part of our asset replacement baseline allowance.
- For SP Manweb, we have currently excluded expenditure on mural wiring but will assess the proposed expenditure as part of our assessment of rising mains and laterals.

Further details on Non Core Costs

1.93. As discussed in chapter 3 there are number of areas of expenditure where there is insufficient clarity to make firm baseline proposals at this stage. These include:

- Major system risks expenditure (High Impact, Low Probability (HILP) only),
- BT 21st century expenditure,
- Expenditure on rising mains and laterals, and

- Expenditure on Critical National Infrastructure costs (e.g. preparation for black start) and physical security.

1.94. As discussed in Chapter 2 we have also excluded discretionary from the DNO forecast and at this stage no costs have been included in the baseline.

1.95. The following sections provide further background on these costs, including Ofgem's proposed approach to determining proposals for each of these areas as part of our autumn update.

HILP

1.96. Table 17 below sets out the DNO forecasts for expenditure regarding High Impact Low Probability (HILP) events. For the purposes of initial proposals we have applied a modelling assumption to include these costs as forecast, pending further clarification of the requirements.

Table 17 - HILP

HILP								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Modelling Assumption	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	5.7	-	5.7	0.0	0%	5.7	-
CN_East	0.0	0.0	-	0.0	0.0	0%	0.0	-
ENW	0.0	2.8	-	2.8	0.0	0%	2.8	-
CE_NEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_YEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_Wales	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_West	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_LPN	0.2	50.8	-	50.8	0.0	0%	50.6	-
EDFE_SPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_EPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
SP_Distribution	0.0	4.6	-	4.6	0.0	0%	4.6	-
SP_Manweb	0.0	4.1	-	4.1	0.0	0%	4.1	-
SSE_Hydro	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Southern	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**0.2**	**67.9**	**-**	**67.9**	**0.0**	**0%**	**67.7**	**-**

1.97. In August 2007, a joint BERR/Ofgem discussion paper was presented to the Energy Emergencies Executive Committee (E3C) on the subject of electricity network security to the central business districts (CBDs) of major cities. This area of work is now commonly referred to as investment for HILP events. The paper highlighted the potential impact of low probability network failures and recommended that work should be initiated to consider whether network security should be enhanced for specific CBDs.

1.98. As a result of this paper, an Electricity Networks Association (ENA) Working Group was established to further consider this issue and recommend a way forward to the (E3C). The ENA Working Group completed its work in April 2008. Its final report identified the most significant CBDs based on their economic activity, and estimated the cost of network reinforcement that would provide a material enhancement (to a common standard) to their ability to withstand low probability network faults. It recommended that specific proposals should be refined and brought to Ofgem as part of the DPCR5 investment plans.

1.99. Recognising this work, the case for such HILP investment is now under consideration as part of the DPCR5 process.

1.100. Ofgem has been actively involved in this work since the initial discussion paper to the E3C. However, we have some concerns with providing a higher level of network security (i.e. higher than that required by the distribution licence) to a particular customer group, and in particular how this might be funded. Despite these concerns, we made specific provision for DNOs to submit HILP proposals in their initial FBPQs and their final submissions in February of this year, which were updated in June.

1.101. Further, in order to properly address our concerns about differential treatment of different customer groups, we encouraged the DNOs to raise the HILP issue as part of their stakeholder engagement processes. In particular, we asked the DNOs to try to establish whether CBD customers would in principle be prepared to pay for the enhancement to network security being proposed.

1.102. In the June 2009 FBPQ submissions, HILP investments were proposed in only five of the fourteen licence areas, consistent with the February submissions, totalling £67.9m. This is just three per cent less than the February submissions and is still dominated by the investment proposed by EDFE for London (i.e. 75 per cent of the total). Scottish Power has also proposed HILP investments of £6.1m for specific parts of its networks that are not CBDs.

1.103. As noted previously, a number of DNOs have reported their discussions with CBD stakeholders on the issue of willingness to pay. The responses are reasonably consistent. CBD customers are supportive of the idea that network security should be enhanced but believe that the costs of such enhancement should be shared between all customers.

1.104. Ofgem has had further discussions with DECC regarding the justification for HILP investments. DECC has agreed that it would be very challenging for Ofgem to unilaterally make a decision about the HILP investments because of the difficulty of making a sensible cost benefit assessment against a very low level of risk. We have therefore agreed an alternative approach involving DECC and Ofgem.

1.105. We recognise that the studies carried out by the DNOs for the E3C report were not definitive - they were carried out to give a reasonable indication of the costs involved. What they did show quite clearly was that the costs for London dominated the national total. This has carried through to the FBPQ submissions as noted above.

1.106. We have therefore decided firstly to work with DECC and EDFE to refine the estimates for the London HILP scheme to better understand the key risk scenarios, the available options to address them, the extent of the works involved and the benefits that would be delivered. This study could consider whether any alternative measures (i.e. other than straightforward electrical reinforcement) could deliver similar resilience benefits, perhaps at lower cost. DECC and Ofgem will then jointly seek to identify a way forward, and a decision could then be taken as to what work should be carried out and the mechanism for implementation. The lessons learned from this could then be applied to the other DNOs.

1.107. We are committed to resolving this issue in a timescale that will allow us to set out Initial Proposals as part of our autumn update and agree a way forward with the relevant DNOs as part of our Final Proposals.

BT21CN

1.108. 'BT 21st Century Network' (BT21CN) refers to a series of proposed changes to BT's communication network which may impact on circuits leased by the DNOs for protection signalling and substation communication. Table 18 below shows the DNOs forecasts for BT21CN.

Table 18 - BT21CN

BT21CN								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Modelling Assumption	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	8.9	-	8.9	0.0	0%	8.9	-
CN_East	0.0	23.4	-	23.4	0.0	0%	23.4	-
ENW	5.0	19.6	290%	19.6	0.0	0%	14.5	290%
CE_NEDL	0.0	2.3	-	2.3	0.0	0%	2.3	-
CE_YEDL	0.0	3.2	-	3.2	0.0	0%	3.2	-
WPD_S_Wales	0.1	2.6	3600%	2.6	0.0	0%	2.5	3600%
WPD_S_West	0.1	0.8	636%	0.8	0.0	0%	0.7	636%
EDFE_LPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_SPN	0.0	23.5	-	23.5	0.0	0%	23.5	-
EDFE_EPN	0.6	42.2	6933%	42.2	0.0	0%	41.6	6933%
SP_Distribution	0.0	5.5	-	5.5	0.0	0%	5.5	-
SP_Manweb	3.5	27.8	700%	27.8	0.0	0%	24.3	700%
SSE_Hydro	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Southern	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**9.3**	**159.7**	**1623%**	**159.7**	**0.0**	**0%**	**150.4**	**1623%**

1.109. There is currently insufficient clarity regarding the requirement for these costs and as such we intend to set out our Initial Proposals in these areas as part of our autumn update. For the purposes of the modelling of DNO submissions for Initial Proposals, we have included the current funding requests without adjustment.

CNI security

1.110. The Centre for Protection of National Infrastructure (CPNI) is continuing its review of key DNO sites to establish whether the physical security provisions are currently appropriate or whether they require enhancement. A similar review has been completed for electricity transmission sites, and Ofgem has put in place a mechanism to provide funding for any required security enhancements. We would expect to put in place a similar mechanism for DNO sites when required.

1.111. Four DNOs have sought funding for this work in its FBPQ. We have included the costs in our modelling at this stage pending the development of a common funding mechanism for the autumn update. Table 19 below shows the DNOs forecasts for CNI security.

Table 19 - CNI security

CNI security								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Modelling Assumption	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	2.4	-	2.4	0.0	0.0	2.4	-
CN_East	0.0	2.4	-	2.4	0.0	0%	2.4	-
ENW	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_NEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_YEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_Wales	0.1	0.0	-100%	0.0	0.0	0%	-0.1	-100%
WPD_S_West	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_LPN	4.7	0.0	-100%	0.0	0.0	0%	-4.7	-100%
EDFE_SPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_EPN	0.0	0.0	-	0.0	0.0	0%	0.0	-
SP_Distribution	0.0	5.0	-	5.0	0.0	0%	5.0	-
SP_Manweb	0.0	6.0	-	6.0	0.0	0%	6.0	-
SSE_Hydro	0.0	0.0	-	0.0	0.0	0%	0.0	-
SSE_Southern	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**4.8**	**15.8**	**230%**	**15.8**	**0.0**	**0%**	**11.0**	**230%**

Black Start Capability & Emergency Batteries

Table 20 below sets out the DNO forecasts for expenditure regarding Black Start Capability and Emergency Batteries.

Table 20 - Black Start Capability & Emergency Batteries

Black Start Capability & Emergency Batteries								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Modelling Assumption	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	0.5	-	0.5	0.0	0.0	0.5	-
CN_East	0.0	0.5	-	0.5	0.0	0%	0.5	-
ENW	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_NEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_YEDL	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_Wales	0.0	2.0	-	2.0	0.0	0%	2.0	-
WPD_S_West	0.0	1.4	-	1.4	0.0	0%	1.4	-
EDFE_LPN	0.0	6.6	-	6.6	0.0	0%	6.6	-
EDFE_SPN	0.0	9.0	-	9.0	0.0	0%	9.0	-
EDFE_EPN	0.0	21.0	-	21.0	0.0	0%	21.0	-
SP_Distribution	0.0	0.5	-	0.5	0.0	0%	0.5	-
SP_Manweb	0.0	1.0	-	1.0	0.0	0%	1.0	-
SSE_Hydro	0.0	6.0	-	6.0	0.0	0%	6.0	-
SSE_Southern	0.0	8.0	-	8.0	0.0	0%	8.0	-
Total	**0.0**	**56.6**	**-**	**56.6**	**0.0**	**0%**	**56.6**	**-**

1.112. The Energy Emergencies Executive Committee (E3C) has been actively engaged in a number of reviews of the electricity system's ability to restore supplies in the event of a system Black Start. The performance of critical infrastructure that may need to be enhanced to cope with such an event has been reviewed.

1.113. These reviews have been undertaken through individual specialist task groups with wide representation from industry to investigate the current and future resilience risks and the likely investment that may be necessary to mitigate them. Work is currently in progress that is due to be completed in quarter two 2010. This work will determine whether a national standard is required in this area.

1.114. Five of the seven DNOs have submitted costs for Black Start capability and/or emergency batteries. In the absence of a national standard, Ofgem intends to consult with appropriate parties (including DECC) and take account of E3C recommendations, to establish common guidance on this issue. We will then assess any submissions from DNOs for additional resilience expenditure in due course, using agreed criteria.

1.115. We have decided to include the current funding requests in our modelling at this stage, but we will set out our Initial Proposals for these costs as part of our autumn update.

Rising Mains and Laterals

Table 21 below sets out the DNO forecasts for expenditure regarding Rising Mains and Laterals.

Table 21 - Rising Mains and Laterals

Rising Mains and Laterals									
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Modelling Assumption	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	0.0	-	0.0	0.0	0.0	0.0	-
CN_East	0.0	0.0	-	0.0	0.0	0%	0.0	-
ENW	0.0	0.0	-	0.0	0.0	0%	0.0	-
CE_NEDL	0.0	4.0	-	4.0	0.0	0%	4.0	-
CE_YEDL	0.2	5.9	3342%	5.9	0.0	0%	5.7	3342%
WPD_S_Wales	0.0	0.0	-	0.0	0.0	0%	0.0	-
WPD_S_West	0.0	0.0	-	0.0	0.0	0%	0.0	-
EDFE_LPN	0.0	0.5	-	0.5	0.0	0%	0.5	-
EDFE_SPN	0.7	1.0	43%	1.0	0.0	0%	0.3	43%
EDFE_EPN	0.0	0.5	-	0.5	0.0	0%	0.5	-
SP_Distribution	4.8	38.6	697%	38.6	0.0	0%	33.8	697%
SP_Manweb	0.3	21.3	7507%	21.3	0.0	0%	21.0	7507%
SSE_Hydro	1.4	1.5	7%	1.5	0.0	0%	0.1	7%
SSE_Southern	3.3	5.0	52%	5.0	0.0	0%	1.7	52%
Total	**10.7**	**78.3**	**632%**	**78.3**	**0.0**	**0%**	**67.6**	**632%**

1.116. Some of the DNOs have included the costs of refurbishing rising and lateral mains ("RLM costs") in large-scale housing estates built by local authorities/developers during the 1950s/60s. We understand that the rising and lateral mains associated with these buildings are at the end of their lifespan, and require inspection and replacement for supply reliability and safety purposes. However we also understand that in many of these cases the ownership status of the RLM assets is not clear and therefore it is not clear whether these form part of the DNO network or whether the DNO is responsible for the costs of their replacement.

1.117. As there is currently insufficient clarity or justification regarding the requirement for the RLM costs, we have not assessed these costs and have not determined a baseline for Initial Proposals. We have included the DNOs' forecasts costs in our modelling at this stage pending further review.

1.118. We intend to provide our Initial Proposals in our autumn update. It is noted however, that for RLM unless sufficient evidence (for example, clear evidence regarding ownership) is provided in the next few weeks we would not be able to include these costs within the price control settlement at this time. As these costs may be significant for some DNOs, it is possible that this issue can be addressed through a re-opener or logging-up if the necessary clarity emerges over time.

Discretionary Expenditure

1.119. Table 22 below sets out the DNO forecasts for Discretionary Expenditure.

Table 22 - Discretionary Expenditure

Discretionary expenditure								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction from DNO Forecast	Reduction (%)	Increase DPCR4 to Baseline	Increase (%)
CN_West	0.0	7.0	-	0.0	7.0	0.3	-	-
CN_East	0.0	10.8	-	0.0	10.8	13%	-	-
ENW	0.0	0.0	-	0.0	0.0	-1%	-	-
CE_NEDL	0.0	0.0	-	0.0	0.0	20%	-	-
CE_YEDL	0.0	0.0	-	0.0	0.0	32%	-	-
WPD_S_Wales	0.1	23.8	-	0.0	23.8	48%	-	-
WPD_S_West	0.0	30.7	-	0.0	30.7	61%	-	-
EDFE_LPN	0.0	5.0	-	0.0	5.0	12%	-	-
EDFE_SPN	0.0	11.0	-	0.0	11.0	25%	-	-
EDFE_EPN	0.0	14.0	-	0.0	14.0	22%	-	-
SP_Distribution	0.0	0.6	-	0.0	0.6	14%	-	-
SP_Manweb	0.0	1.5	-	0.0	1.5	14%	-	-
SSE_Hydro	0.0	4.0	-	0.0	4.0	3%	-	-
SSE_Southern	0.0	4.5	-	0.0	4.5	43%	-	-
Total	**0.1**	**112.9**	**-**	**0.0**	**112.9**	**23%**	**-**	**-**

1.120. We invited the DNOs to forecast non core expenditures that they can justify, over and above normal business expenditures in order to increase future network flexibility (Discretionary Expenditure).

1.121. We have assessed the Discretionary Expenditure according to the quality of the justification, especially with respect to whether the expenditure will enable the network to be more flexible in the future (with respect to connecting distributed generation, using demand side management or active network management etc.).

1.122. We consider that some schemes can be more appropriately funded under the Innovation Funding Incentive (IFI). We did not receive sufficient justification for the remainder of the expenditures for us to be able to adequately assess the schemes. Our initial proposals therefore do not include any discretionary expenditures.

1.123. We are disappointed by the lack of justification provided in support of the proposed schemes, and urge the DNOs to develop stronger proposals. If a DNO submits a proposal to us by September with a detailed and thorough justification we will consider whether the proposed expenditures can be included within our final proposals.

1.124. During DPCR5 the DNOs will be able to submit proposals for expenditures to increase future network flexibility for funding under the low carbon network fund, meaning that the fact that these expenditures have not been included in our initial proposals does not mean that the initiatives will not take place during DPCR5.

Appendix 7 – Network Investment - DNO Specific Adjustments

1.125. The following section contains two tables for each DNO. The first table provides an overall breakdown by DNO of our proposed baselines for core and non-core network investment. Non-core investment is split between areas where we are proposing a baseline as part of Initial Proposals, and those areas where we have not yet developed our proposals and have therefore applied a modelling assumption.

1.126. Given the high materiality of asset replacement, the second table provides an asset specific breakdown of the DNOs' forecasts and Ofgem's baseline for modelled asset replacement expenditure, split between volume and unit costs.

CN West

Table 1 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

CN West								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	52.1	25.8	-50%	25.8	0.0	0%	-26.3	-50%
Diversions	30.7	41.7	36%	36.2	5.5	13%	5.5	18%
Reinforcement	103.2	149.0	44%	127.9	21.0	14%	24.7	24%
Fault Levels	0.0	25.7	-	19.6	6.1	24%	19.6	-
Asset Replacement	270.2	376.7	39%	327.7	49.0	13%	57.5	21%
Operational IT&T	3.1	2.1	-32%	2.1	0.0	0%	-1.0	-32%
Legal and Safety	10.8	17.6	63%	14.7	2.9	16%	3.9	37%
Total	**470.1**	**638.6**	**36%**	**554.1**	**84.5**	**13.2%**	**84.0**	**18%**
Non Core (Baseline)								
Flooding	0.3	2.4	690%	2.0	0.4	18%	1.7	550%
QoS (IIS)	27.2	7.4	-73%	0.0	7.4	100%	-27.2	-100%
QoS (Non IIS)	0.0	1.6	-	0.0	1.6	100%	0.0	-
Environmental	0.1	0.1	-46%	0.1	0.0	0%	0.0	-46%
Losses	0.0	2.3	-	2.0	0.3	12%	2.0	-
Total	**27.6**	**13.7**	**-50%**	**4.0**	**9.7**	**71%**	**-23.5**	**-85%**
Non Core (Modelling Assumptions)								
HILP	0.0	5.7	-	5.7	0.0	0%	5.7	-
BT21CN	0.0	8.9	-	8.9	0.0	0%	8.9	-
CNI security	0.0	2.4	-	2.4	0.0	0%	2.4	-
Black Start Capability	0.0	0.5	-	0.5	0.0	0%	0.5	-
Rising mains	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**0.0**	**17.5**	**-**	**17.5**	**0.0**	**0%**	**17.5**	**-**
Total Baseline	**497.7**	**669.8**	**35%**	**575.6**	**94.2**	**14.1%**	**77.9**	**16%**

Table 2 Asset Replacement - Asset Specific Adjustments

CN West £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
132 kV CB (ID & OD)	42.0	33.1	8.8	0.0	8.8
132kV UG Cable (Non Pressurised)	33.8	29.0	4.8	0.9	3.8
132kV OHL Conductor (Tower Line)	14.1	10.7	3.5	0.6	2.8
132kV Tower	5.4	2.0	3.4	3.4	0.0
6.6/11 kV Transformer (GM)	8.6	6.1	2.5	0.0	2.5
LV Main (UG Plastic)	48.1	46.0	2.1	2.1	0.0
132 kV Transformer	22.5	20.5	2.0	2.0	0.0
6.6/11 kV RMU	16.7	15.0	1.7	0.9	0.8
6.6/11kV UG Cable	6.8	5.5	1.4	0.0	1.4
33kV UG Cable (Non Pressurised)	7.9	6.6	1.3	0.0	1.3
6.6/11 kV Transformer (PM)	3.1	1.8	1.3	0.0	1.3
Service Replacement (UG)	7.3	6.6	0.7	0.7	0.0
33 kV CB (OD)	3.3	2.7	0.6	0.6	0.0
33kV OHL (Tower Line)	2.1	1.7	0.5	0.0	0.4
6.6/11 kV CB (PM)	2.0	1.5	0.4	0.4	0.0
Total	223.7	188.6	35.1	11.9	23.2

CN East

Table 3 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

CN East								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	87.1	66.1	-24%	66.1	0.0	0%	-21.1	-24%
Diversions	42.5	54.8	29%	47.4	7.4	13%	4.9	12%
Reinforcement	111.6	187.3	68%	158.8	28.6	15%	47.2	42%
Fault Levels	13.9	9.4	-33%	9.4	0.0	0%	-4.6	-33%
Asset Replacement	191.3	285.3	49%	236.7	48.6	17%	45.4	24%
Operational IT&T	2.9	10.2	253%	10.2	0.0	0%	7.3	253%
Legal and Safety	7.2	17.4	141%	14.0	3.5	20%	6.7	93%
Total	**456.6**	**630.5**	**38%**	**542.5**	**88.0**	**14.0%**	**85.9**	**19%**
Non Core (Baseline)								
Flooding	0.1	8.4	9781%	6.9	1.5	18%	6.8	8003%
QoS (IIS)	24.6	2.2	-91%	0.0	2.2	100%	-24.6	-100%
QoS (Non IIS)	1.0	1.6	55%	0.0	1.6	100%	-1.0	-100%
Environmental	1.3	1.7	25%	1.7	0.0	0%	0.3	25%
Losses	0.0	1.4	-	1.3	0.1	7%	1.3	-
Total	**27.0**	**15.3**	**-43%**	**9.9**	**5.4**	**35%**	**-17.1**	**-63%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	23.4	-	23.4	0.0	0%	23.4	-
CNI security	0.0	2.4	-	2.4	0.0	0%	2.4	-
Black Start Capability	0.0	0.5	-	0.5	0.0	0%	0.5	-
Rising mains	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**0.0**	**26.3**	**-**	**26.3**	**0.0**	**0%**	**26.3**	**-**
Total Baseline	**483.6**	**672.1**	**39%**	**578.7**	**93.4**	**13.9%**	**95.1**	**20%**

Table 4 Asset Replacement - Asset Specific Adjustments

CN East £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
132 kV CB (ID & OD)	34.5	23.8	10.7	0.0	10.7
33 kV CB (OD)	16.3	9.4	7.0	7.0	0.0
132kV UG Cable (Non Pressurised)	33.9	28.5	5.4	5.4	0.0
33 kV Transformer (GM)	9.8	7.2	2.6	2.6	0.0
6.6/11 kV RMU	30.2	27.6	2.6	1.7	0.9
6.6/11 kV Transformer (GM)	5.6	3.2	2.4	0.0	2.4
33 kV RMU	4.0	2.1	1.9	0.0	1.9
132kV Tower	3.0	1.1	1.9	1.9	0.0
33kV UG Cable (Non Pressurised)	8.3	6.4	1.9	0.3	1.5
132kV OHL Conductor (Tower Line)	6.6	5.3	1.3	0.0	1.3
6.6/11kV UG Cable	6.2	5.0	1.2	0.0	1.2
Service Replacement	6.6	5.6	1.0	1.0	0.0
33kV OHL (Tower Line)	0.8	0.6	0.2	0.0	0.2
Total	165.8	125.8	40.0	19.8	20.2

ENW

Table 5 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

ENW								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	72.9	37.2	-49%	37.2	0.0	0%	-35.7	-49%
Diversions	11.1	23.1	109%	12.2	10.9	47%	1.1	10%
Reinforcement	68.0	93.6	38%	87.1	6.4	7%	19.2	28%
Fault Levels	4.8	2.5	-49%	2.5	0.0	0%	-2.3	-49%
Asset Replacement	235.7	349.9	48%	284.1	65.9	19%	48.4	21%
Operational IT&T	12.7	16.4	29%	15.0	1.4	9%	2.3	18%
Legal and Safety	16.0	61.2	283%	36.7	24.6	40%	20.7	129%
Total	**421.1**	**583.9**	**39%**	**474.6**	**109.2**	**18.7%**	**53.6**	**13%**
Non Core (Baseline)								
Flooding	3.2	7.4	135%	5.9	1.6	21%	2.7	85%
QoS (IIS)	6.6	0.0	-100%	0.0	0.0	0%	-6.6	-100%
QoS (Non IIS)	0.0	0.0	-	0.0	0.0	0%	0.0	-
Environmental	3.8	2.2	-42%	2.2	0.0	0%	-1.6	-42%
Losses	0.2	0.0	-100%	1.8	-1.8	0%	1.6	1001%
Total	**13.7**	**9.7**	**-29%**	**9.9**	**-0.2**	**-2%**	**-3.8**	**-28%**
Non Core (Modelling Assumptions)								
HILP	0.0	2.8	-	2.8	0.0	0%	2.8	-
BT21CN	5.0	19.6	290%	19.6	0.0	0%	14.5	290%
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	0.0	-	0.0	0.0	0%	0.0	-
Rising mains	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**5.0**	**22.4**	**346%**	**22.4**	**0.0**	**0%**	**17.4**	**346%**
Total Baseline	**439.8**	**615.9**	**40%**	**506.9**	**109.0**	**17.7%**	**67.1**	**15%**

Table 6 Asset Replacement - Asset Specific Adjustments

ENW £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
LV Main (UG Plastic)	30.2	22.9	7.3	0.0	7.3
132 kV CB (ID & OD)	13.1	6.9	6.2	6.2	0.0
132 kV Transformer	19.7	14.0	5.7	0.2	5.5
132kV OHL Conductor (Tower Line)	11.6	7.8	3.8	3.8	0.0
33 kV Transformer (GM)	13.6	11.2	2.4	2.4	0.0
6.6/11 kV Transformer (GM)	17.2	15.0	2.3	0.0	2.3
132kV Tower	2.4	0.3	2.1	2.1	0.0
6.6/11 kV RMU	13.1	11.0	2.1	0.4	1.7
6.6/11 kV CB (GM) Distribution	6.6	5.7	0.8	0.8	0.0
132kV Fittings (Tower Line)	3.3	2.5	0.8	0.8	0.0
Cut out Replacement	8.8	8.3	0.5	0.5	0.0
6.6/11kV UG Cable	16.2	15.7	0.5	0.5	0.0
33kV OHL (Tower Line)	1.4	0.9	0.5	0.5	0.0
Service Replacement	0.4	0.3	0.1	0.1	0.0
6.6/11 kV CB (PM)	0.3	0.3	0.1	0.1	0.0
6.6/11 kV Transformer (PM)	0.5	0.4	0.0	0.0	0.0
Total	158.5	123.3	35.2	18.5	16.7

CE NEDL

Table 7 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

CE NEDL								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	11.0	20.0	82%	20.0	0.0	0%	9.0	82%
Diversions	15.9	19.7	24%	15.2	4.5	23%	-0.7	-4%
Reinforcement	61.2	56.4	-8%	56.3	0.0	0%	-4.9	-8%
Fault Levels	1.0	8.9	817%	8.9	0.0	0%	8.0	817%
Asset Replacement	154.9	279.2	80%	236.6	42.7	15%	81.7	53%
Operational IT&T	0.4	0.4	15%	0.4	0.0	0%	0.1	15%
Legal and Safety	8.3	8.7	5%	8.0	0.7	26%	-0.2	-3%
Total	**252.7**	**393.4**	**56%**	**345.5**	**47.8**	**12.2%**	**92.9**	**37%**
Non Core (Baseline)								
Flooding	0.6	2.5	323%	2.4	0.1	5%	1.8	302%
QoS (IIS)	15.3	2.4	-84%	0.0	2.4	100%	-15.3	-100%
QoS (Non IIS)	0.7	0.0	-100%	0.0	0.0	0%	-0.7	-100%
Environmental	1.5	1.2	-21%	1.2	0.0	0%	-0.3	-21%
Losses	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**18.1**	**6.1**	**-66%**	**3.6**	**2.5**	**41%**	**-14.5**	**-80%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	2.3	-	2.3	0.0	0%	2.3	-
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	0.0	-	0.0	0.0	0%	0.0	-
Rising mains	0.0	4.0	-	4.0	0.0	0%	4.0	-
Total	**0.0**	**6.3**	**-**	**6.3**	**0.0**	**0%**	**6.3**	**-**
Total Baseline	**270.7**	**405.9**	**50%**	**355.5**	**50.4**	**12.4%**	**84.7**	**31%**

Table 8 Asset Replacement - Asset Specific Adjustments

CE NEDL £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
LV Main (UG Plastic)	16.6	9.2	7.4	7.4	0.0
6.6/11 kV RMU	13.8	8.5	5.3	5.3	0.0
132kV Fittings (Tower Line)	7.3	3.4	3.9	3.9	0.0
132kV OHL Conductor (Tower Line)	10.1	6.4	3.7	3.7	0.0
66kV UG Cable (Non Pressurised)	9.8	8.3	1.6	0.0	1.6
33kV UG Cable (Non Pressurised)	11.2	9.8	1.4	0.0	1.4
66 KV CB (ID & OD)	18.7	17.6	1.1	1.1	0.0
20 kV RMU	2.7	1.6	1.0	1.0	0.0
6.6/11 kV Switch (GM)	2.7	1.7	1.0	1.0	0.0
132kV UG Cable (Non Pressurised)	4.9	3.9	1.0	0.0	1.0
LV Pillar (ID)	4.3	3.3	1.0	1.0	0.0
6.6/11kV UG Cable	12.7	11.9	0.8	0.8	0.0
Cut out Replacement	5.8	5.0	0.7	0.7	0.0
Service Replacement	2.2	1.5	0.7	0.7	0.0
6.6/11 kV CB (GM) Distribution	2.4	1.7	0.6	0.6	0.0
6.6/11 kV Transformer (GM)	10.7	10.1	0.6	0.6	0.0
LV Board (WM)	2.9	2.3	0.6	0.6	0.0
6.6/11 kV CB (GM) Primary	3.1	2.5	0.6	0.6	0.0
LV Pillar (OD)	2.4	1.9	0.5	0.5	0.0
20 kV Transformer (GM)	2.2	1.7	0.5	0.5	0.0
Total	146.4	112.2	34.2	30.3	4.0

CE YEDL

Table 9 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

CE YEDL								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	9.8	28.7	193%	28.7	0.0	0%	18.9	193%
Diversions	28.2	44.5	58%	31.3	13.3	30%	3.1	11%
Reinforcement	49.3	62.7	27%	62.7	0.0	0%	13.4	27%
Fault Levels	2.7	14.1	415%	14.1	0.0	0%	11.4	415%
Asset Replacement	217.5	330.2	52%	271.7	58.5	18%	54.2	25%
Operational IT&T	3.7	0.4	-88%	0.4	0.0	0%	-3.2	-88%
Legal and Safety	19.3	23.0	19%	16.9	6.1	26%	-2.4	-12%
Total	**330.5**	**503.7**	**52%**	**425.8**	**77.8**	**15.5%**	**95.4**	**29%**
Non Core (Baseline)								
Flooding	2.1	7.8	269%	6.9	0.8	11%	4.8	229%
QoS (IIS)	18.1	7.6	-58%	0.0	7.6	100%	-18.1	-100%
QoS (Non IIS)	0.0	0.0	-	0.0	0.0	0%	0.0	-
Environmental	1.6	1.9	23%	1.9	0.0	0%	0.4	23%
Losses	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**21.8**	**17.3**	**-21%**	**8.9**	**8.5**	**49%**	**-12.9**	**-59%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	3.2	-	3.2	0.0	0%	3.2	-
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	0.0	-	0.0	0.0	0%	0.0	-
Rising mains	0.2	5.9	3342%	5.9	0.0	0%	5.7	3342%
Total	**0.2**	**9.1**	**5243%**	**9.1**	**0.0**	**0%**	**8.9**	**5243%**
Total Baseline	**352.4**	**530.1**	**50%**	**443.8**	**86.3**	**16.3%**	**91.3**	**26%**

Table 10 Asset Replacement - Asset Specific Adjustments

CE YEDL £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
LV Main (UG Plastic)	22.1	12.0	10.1	10.1	0.0
6.6/11 kV RMU	20.9	12.3	8.5	8.5	0.0
132kV Fittings (Tower Line)	11.9	4.9	7.0	7.0	0.0
132kV OHL Conductor (Tower Line)	15.8	9.2	6.6	6.6	0.0
132kV UG Cable (Non Pressurised)	19.4	16.1	3.3	0.0	3.3
6.6/11 kV Switch (GM)	7.7	4.6	3.0	3.0	0.0
33kV UG Cable (Non Pressurised)	19.3	17.0	2.3	0.0	2.3
LV Pillar (ID)	5.6	4.0	1.5	1.5	0.0
6.6/11 kV CB (GM) Distribution	4.7	3.3	1.4	1.4	0.0
132 kV Transformer	8.9	7.5	1.4	1.4	0.0
6.6/11 kV Transformer (GM)	15.6	14.4	1.2	1.2	0.0
6.6/11 kV CB (GM) Primary	4.7	3.7	1.0	1.0	0.0
LV Board (WM)	3.9	2.9	1.0	1.0	0.0
33 KV CB (ID)	1.3	0.7	0.7	0.7	0.0
LV Pillar (OD)	2.5	1.9	0.7	0.7	0.0
33 kV Transformer (GM)	3.4	3.2	0.2	0.2	0.0
66 kV Transformer	5.5	5.5	0.0	0.0	0.0
6.6/11 kV Transformer (PM)	0.1	0.1	0.0	0.0	0.0
Total	173.2	123.2	50.0	44.4	5.6

WPD S Wales

Table 11 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

WPD S Wales								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	6.0	5.4	-10%	5.4	0.0	0%	-0.6	-10%
Diversions	14.2	14.0	-2%	14.0	0.0	0%	-0.2	-2%
Reinforcement	22.8	19.9	-13%	18.3	1.6	8%	-4.5	-20%
Fault Levels	0.0	0.7	-	0.7	0.0	0%	0.7	-
Asset Replacement	84.5	133.7	58%	129.7	4.0	3%	45.2	54%
Operational IT&T	9.9	8.8	-11%	7.0	1.8	21%	-2.9	-30%
Legal and Safety	1.2	13.9	1054%	7.5	6.4	46%	6.3	525%
Total	**138.6**	**196.3**	**42%**	**182.6**	**13.7**	**7.0%**	**44.0**	**32%**
Non Core (Baseline)								
Flooding	1.0	10.8	991%	8.2	2.6	24%	7.2	729%
QoS (IIS)	17.0	0.8	-95%	0.0	0.8	100%	-17.0	-100%
QoS (Non IIS)	0.0	3.0	-	0.0	3.0	100%	0.0	-
Environmental	0.0	3.3	-	3.3	0.0	0%	3.3	-
Losses	0.0	8.5	-	0.0	8.5	100%	0.0	-
Total	**18.0**	**26.3**	**46%**	**11.5**	**14.9**	**56%**	**-6.5**	**-36%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.1	2.6	3600%	2.6	0.0	0%	2.5	3600%
CNI security	0.1	0.0	-100%	0.0	0.0	0%	-0.1	-100%
Black Start Capability	0.0	2.0	-	2.0	0.0	0%	2.0	-
Rising mains	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**0.2**	**4.6**	**2594%**	**4.6**	**0.0**	**0%**	**4.4**	**2594%**
Total Baseline	**156.8**	**227.2**	**45%**	**198.6**	**28.6**	**12.6%**	**41.9**	**27%**

Table 12 Asset Replacement - Asset Specific Adjustments

WPD S Wales £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
Service Replacement	4.7	2.2	2.5	2.5	0.0
6.6/11 kV CB (GM) Distribution	0.9	0.5	0.4	0.4	0.0
EHV Sub Cable	0.5	0.2	0.4	0.4	0.0
132kV UG Cable (Non Pressurised)	2.7	2.5	0.2	0.2	0.0
33 kV Switch (GM)	0.1	0.0	0.1	0.1	0.0
HV Sub Cable	0.2	0.2	0.1	0.1	0.0
6.6/11 kV Switch (PM)	0.1	0.1	0.0	0.0	0.0
33kV Tower	0.2	0.2	0.0	0.0	0.0
Total	9.6	5.8	3.8	3.8	0.0

WPD S West

Table 13 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

WPD S West								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	10.7	7.8	-27%	7.8	0.0	0%	-2.9	-27%
Diversions	18.0	26.0	44%	21.7	4.3	17%	3.7	20%
Reinforcement	33.9	20.3	-40%	20.3	0.0	0%	-13.7	-40%
Fault Levels	0.0	2.9	-	2.9	0.0	0%	2.9	-
Asset Replacement	157.9	211.7	34%	204.0	7.8	4%	46.1	29%
Operational IT&T	11.1	12.9	16%	11.1	1.8	14%	0.0	0%
Legal and Safety	6.7	27.9	319%	19.6	8.4	30%	12.9	194%
Total	**238.3**	**309.5**	**30%**	**287.2**	**22.3**	**7.2%**	**48.9**	**21%**
Non Core (Baseline)								
Flooding	1.0	6.8	576%	6.1	0.7	10%	5.1	511%
QoS (IIS)	12.2	0.0	-100%	0.0	0.0	0%	-12.2	-100%
QoS (Non IIS)	0.0	11.3	-	0.0	11.3	100%	0.0	-
Environmental	0.6	7.1	1065%	7.1	0.0	0%	6.5	1065%
Losses	0.0	11.8	-	0.0	11.8	100%	0.0	-
Total	**13.8**	**36.9**	**167%**	**13.2**	**23.7**	**64%**	**-0.6**	**-5%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.1	0.8	636%	0.8	0.0	0%	0.7	636%
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	1.4	-	1.4	0.0	0%	1.4	-
Rising mains	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**0.1**	**2.2**	**1909%**	**2.2**	**0.0**	**0%**	**2.1**	**1909%**
Total Baseline	**252.2**	**348.6**	**38%**	**302.6**	**46.0**	**13.2%**	**50.4**	**20%**

Table 14 Asset Replacement - Asset Specific Adjustments

WPD S West £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
Service Replacement	7.8	3.9	3.9	3.9	0.0
EHV Sub Cable	3.5	1.0	2.5	2.5	0.0
132kV UG Cable (Non Pressurised)	7.6	7.0	0.6	0.6	0.0
6.6/11 kV CB (GM) Distribution	1.4	0.8	0.6	0.6	0.0
HV Sub Cable	0.2	0.2	0.1	0.1	0.0
33 kV Switch (GM)	0.1	0.0	0.1	0.1	0.0
Total	20.6	12.8	7.8	7.8	0.0

EDFE LPN

Table 15 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

EDFE LPN								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	5.6	10.5	88%	10.5	0.0	0%	4.9	88%
Diversions	5.7	4.2	-26%	3.7	0.5	12%	-2.0	-35%
Reinforcement	103.7	209.8	102%	199.7	10.1	5%	96.0	93%
Fault Levels	4.1	1.3	-68%	1.3	0.0	0%	-2.8	-68%
Asset Replacement	254.8	275.2	8%	210.1	65.1	24%	-44.7	-18%
Operational IT&T	9.0	3.2	-64%	3.2	0.0	0%	-5.8	-64%
Legal and Safety	4.6	3.9	-15%	2.9	1.0	26%	-1.7	-37%
Total	**387.5**	**508.1**	**31%**	**431.4**	**76.7**	**15.1%**	**43.9**	**11%**
Non Core (Baseline)								
Flooding	0.5	4.1	720%	3.4	0.7	17%	2.9	577%
QoS (IIS)	3.6	8.0	122%	0.0	8.0	100%	-3.6	-100%
QoS (Non IIS)	0.0	0.0	-	0.0	0.0	0%	0.0	-
Environmental	4.1	2.5	-39%	2.5	0.0	0%	-1.6	-39%
Losses	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**8.2**	**14.6**	**78%**	**5.9**	**8.7**	**60%**	**-2.3**	**-28%**
Non Core (Modelling Assumptions)								
HILP	0.2	50.8	25300%	50.8	0.0	0%	50.6	25300%
BT21CN	0.0	0.0	-	0.0	0.0	0%	0.0	-
CNI security	4.7	0.0	-100%	0.0	0.0	0%	-4.7	-100%
Black Start Capability	0.0	6.6	-	6.6	0.0	0%	6.6	-
Rising mains	0.0	0.5	-	0.5	0.0	0%	0.5	-
Total	**4.9**	**57.9**	**1082%**	**57.9**	**0.0**	**0%**	**53.0**	**1082%**
Total Baseline	**400.6**	**580.6**	**45%**	**495.2**	**85.4**	**14.7%**	**94.6**	**24%**

Table 16 Asset Replacement - Asset Specific Adjustments

EDFE LPN £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
132 kV CB (ID & OD)	41.3	21.5	19.8	19.8	0.0
132kV UG Cable (Non Pressurised)	32.8	17.8	15.0	11.9	3.1
6.6/11 kV CB (GM) Distribution	8.2	1.8	6.3	6.3	0.0
Cut out Replacement	5.3	2.0	3.3	3.3	0.0
6.6/11 kV RMU	34.0	31.0	3.0	3.0	0.0
6.6/11kV UG Cable	7.2	4.5	2.7	2.7	0.0
66 kV Transformer	3.5	0.9	2.6	2.6	0.0
66 KV CB (ID & OD)	2.7	0.6	2.0	2.0	0.0
33kV UG Cable (Non Pressurised)	5.9	4.0	2.0	2.0	0.0
LV Board (WM)	3.3	1.4	1.9	1.9	0.0
33 kV Transformer (GM)	3.5	2.4	1.1	1.1	0.0
LV Main (UG Plastic)	2.4	1.5	0.9	0.9	0.0
6.6/11 kV Transformer (GM)	8.5	8.2	0.3	0.3	0.0
33 KV CB (ID)	2.8	2.6	0.2	0.2	0.0
Service Replacement	0.6	0.5	0.1	0.1	0.0
Total	161.9	100.7	61.2	58.1	3.1

EDFE SPN

Table 17 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

EDFE SPN								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	57.3	48.1	-16%	48.1	0.0	0%	-9.2	-16%
Diversions	21.8	27.5	26%	23.7	3.8	14%	1.9	9%
Reinforcement	69.7	107.3	54%	81.9	25.4	24%	12.2	17%
Fault Levels	0.6	3.0	400%	3.0	0.0	0%	2.4	400%
Asset Replacement	213.5	286.5	34%	246.9	39.6	14%	33.4	16%
Operational IT&T	8.7	2.1	-76%	2.1	0.0	0%	-6.6	-76%
Legal and Safety	12.8	66.7	421%	43.0	23.7	36%	30.2	236%
Total	**384.4**	**541.2**	**41%**	**448.6**	**92.6**	**17.1%**	**64.2**	**17%**
Non Core (Baseline)								
Flooding	0.5	6.0	1100%	5.7	0.3	6%	5.2	1031%
QoS (IIS)	19.0	15.0	-21%	0.0	15.0	100%	-19.0	-100%
QoS (Non IIS)	12.2	0.0	-100%	0.0	0.0	0%	-12.2	-100%
Environmental	4.8	6.5	35%	6.5	0.0	0%	1.7	35%
Losses	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**36.5**	**27.5**	**-25%**	**12.2**	**15.3**	**56%**	**-24.3**	**-67%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	23.5	-	23.5	0.0	0%	23.5	-
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	9.0	-	9.0	0.0	0%	9.0	-
Rising mains	0.7	1.0	43%	1.0	0.0	0%	0.3	43%
Total	**0.7**	**33.5**	**4686%**	**33.5**	**0.0**	**0%**	**32.8**	**4686%**
Total Baseline	**421.6**	**602.2**	**43%**	**494.3**	**107.9**	**17.9%**	**72.7**	**17%**

Table 18 Asset Replacement - Asset Specific Adjustments

EDFE SPN £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
132 kV CB (ID & OD)	25.8	19.4	6.4	6.4	0.0
6.6/11 kV RMU	17.6	13.4	4.2	4.2	0.0
132 kV Transformer	12.1	8.6	3.5	3.5	0.0
33 kV Transformer (GM)	10.0	6.8	3.2	3.2	0.0
Service Replacement	4.3	2.1	2.2	2.2	0.0
33kV UG Cable (Non Pressurised)	17.8	15.9	1.9	1.9	0.0
6.6/11 kV Transformer (GM)	5.6	4.9	0.7	0.7	0.0
Cut out Replacement	2.8	2.2	0.6	0.6	0.0
6.6/11 kV CB (GM) Primary	8.4	7.9	0.5	0.5	0.0
Cut out Replacement	0.2	0.2	0.0	0.0	0.0
LV Main (UG Plastic)	1.2	1.2	0.0	0.0	0.0
Total	105.7	82.4	23.3	23.3	0.0

EDFE EPN

Table 19 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

EDFE EPN								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	30.9	28.8	-7%	28.8	0.0	0%	-2.1	-7%
Diversions	36.8	40.5	10%	39.8	0.7	2%	3.0	8%
Reinforcement	198.4	246.5	24%	199.4	47.1	19%	1.0	0%
Fault Levels	2.8	28.3	911%	25.1	3.2	11%	22.3	795%
Asset Replacement	267.8	257.1	-4%	208.3	48.8	19%	-59.5	-22%
Operational IT&T	3.8	4.4	16%	4.4	0.0	0%	0.6	16%
Legal and Safety	28.6	71.1	149%	40.0	31.1	44%	11.4	40%
Total	**569.1**	**676.7**	**19%**	**545.8**	**130.9**	**19.3%**	**-23.3**	**-4%**
Non Core (Baseline)								
Flooding	0.6	7.5	1150%	6.6	0.9	12%	6.0	1005%
QoS (IIS)	16.4	20.9	27%	0.0	20.9	100%	-16.4	-100%
QoS (Non IIS)	41.3	0.0	-100%	0.0	0.0	0%	-41.3	-100%
Environmental	8.9	7.6	-15%	7.6	0.0	0%	-1.3	-15%
Losses	0.0	0.0	-	0.0	0.0	0%	0.0	-
Total	**67.2**	**36.0**	**-46%**	**14.2**	**21.8**	**60%**	**-53.0**	**-79%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.6	42.2	6933%	42.2	0.0	0%	41.6	6933%
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	21.0	-	21.0	0.0	0%	21.0	-
Rising mains	0.0	0.5	-	0.5	0.0	0%	0.5	-
Total	**0.6**	**63.7**	**10517%**	**63.7**	**0.0**	**0%**	**63.1**	**10517%**
Total Baseline	**636.9**	**776.4**	**22%**	**623.7**	**152.7**	**19.7%**	**-13.2**	**-2%**

Table 20 Asset Replacement - Asset Specific Adjustments

EDFE EPN £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
33kV UG Cable (Non Pressurised)	19.7	11.4	8.3	3.5	4.8
132 kV CB (ID & OD)	10.1	7.6	2.5	2.5	0.0
6.6/11 kV CB (GM) Primary	18.2	15.8	2.4	2.4	0.0
33 kV Transformer (GM)	13.0	10.8	2.2	2.2	0.0
132 kV Transformer	6.4	4.3	2.0	2.0	0.0
Cut out Replacement	2.0	1.0	1.0	1.0	0.0
33kV OHL (Tower Line)	1.3	0.4	0.9	0.9	0.0
33 KV CB (ID)	11.0	10.1	0.8	0.8	0.0
6.6/11 kV Transformer (GM)	6.0	5.2	0.8	0.8	0.0
6.6/11 kV RMU	16.5	15.8	0.7	0.7	0.0
132kV UG Cable (Non Pressurised)	3.2	2.8	0.4	0.4	0.0
LV Board (WM)	0.5	0.2	0.3	0.3	0.0
6.6/11 kV CB (GM) Distribution	6.0	5.8	0.2	0.2	0.0
Cut out Replacement	0.2	0.1	0.1	0.1	0.0
6.6/11 kV CB (PM)	0.3	0.2	0.1	0.1	0.0
Total	114.5	91.8	22.7	17.9	4.8

DPCR5 IP - Allowed Revenue Cost Assessment Supplementary Appendices
3 August 2009

SP Distribution

Table 21 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

SP Distribution								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	21.7	16.2	-26%	16.2	0.0	0%	-5.5	-26%
Diversions	12.4	12.8	3%	12.0	0.8	6%	-0.4	-3%
Reinforcement	43.9	61.8	41%	61.8	0.0	0%	17.9	41%
Fault Levels	1.1	17.3	1542%	17.3	0.0	0%	16.3	1542%
Asset Replacement	222.7	254.8	14%	218.0	36.8	14%	-4.8	-2%
Operational IT&T	7.7	5.2	-33%	4.3	1.0	19%	-3.5	-45%
Legal and Safety	14.2	15.5	9%	13.5	2.0	13%	-0.6	-4%
Total	**323.7**	**383.6**	**19%**	**343.0**	**40.5**	**10.6%**	**19.3**	**6%**
Non Core (Baseline)								
Flooding	0.3	3.2	942%	2.6	0.5	17%	2.3	765%
QoS (IIS)	24.7	7.9	-68%	0.0	7.9	100%	-24.7	-100%
QoS (Non IIS)	0.0	2.0	-	0.0	2.0	100%	0.0	-
Environmental	1.0	5.5	469%	5.5	0.0	0%	4.5	469%
Losses	0.0	0.0	-	0.6	-0.6	0%	0.6	-
Total	**26.0**	**18.6**	**-28%**	**8.7**	**9.8**	**53%**	**-17.2**	**-66%**
Non Core (Modelling Assumptions)								
HILP	0.0	4.6	-	4.6	0.0	0%	4.6	-
BT21CN	0.0	5.5	-	5.5	0.0	0%	5.5	-
CNI security	0.0	5.0	-	5.0	0.0	0%	5.0	-
Black Start Capability	0.0	0.5	-	0.5	0.0	0%	0.5	-
Rising mains	4.8	38.6	697%	38.6	0.0	0%	33.8	697%
Total	**4.8**	**54.2**	**1018%**	**54.2**	**0.0**	**0%**	**49.3**	**1018%**
Total Baseline	**354.5**	**456.3**	**29%**	**405.9**	**50.4**	**11.0%**	**51.4**	**15%**

Table 22 Asset Replacement - Asset Specific Adjustments

SP Distribution £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
LV Main (UG Plastic)	45.9	30.2	15.6	0.0	15.6
33 KV CB (ID)	17.8	6.5	11.3	2.4	8.9
33kV UG Cable (Non Pressurised)	10.7	9.4	1.3	0.8	0.6
6.6/11 kV RMU	12.8	11.7	1.1	1.1	0.0
6.6/11 kV Transformer (PM)	2.6	2.1	0.4	0.0	0.4
LV Pillar (OD)	4.1	3.8	0.2	0.2	0.0
LV Pillar (ID)	1.5	1.3	0.2	0.2	0.0
6.6/11kV UG Cable	14.2	14.1	0.1	0.1	0.0
6.6/11 kV Transformer (GM)	1.6	1.6	0.0	0.0	0.0
Total	111.1	80.8	30.3	4.8	25.5

SP Manweb

Table 23 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

SP Manweb								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	36.1	40.1	11%	40.1	0.0	0%	4.0	11%
Diversions	14.8	23.9	61%	16.9	7.0	29%	2.1	14%
Reinforcement	37.6	80.0	113%	77.8	2.2	3%	40.2	107%
Fault Levels	5.9	14.7	149%	14.7	0.0	0%	8.8	149%
Asset Replacement	233.8	333.0	42%	290.8	42.2	13%	57.0	24%
Operational IT&T	5.8	11.3	95%	10.6	0.8	7%	4.7	82%
Legal and Safety	29.8	43.7	47%	31.4	12.3	28%	1.6	5%
Total	**363.8**	**546.7**	**50%**	**482.2**	**64.5**	**11.8%**	**118.5**	**33%**
Non Core (Baseline)								
Flooding	0.2	11.4	5731%	6.4	4.9	44%	6.2	3193%
QoS (IIS)	19.2	5.5	-71%	0.0	5.5	100%	-19.2	-100%
QoS (Non IIS)	0.0	2.0	-	0.0	2.0	100%	0.0	-
Environmental	2.1	4.5	112%	4.5	0.0	0%	2.4	112%
Losses	0.0	0.0	-	0.5	-0.5	0%	0.5	-
Total	**21.5**	**23.4**	**8%**	**11.4**	**12.0**	**51%**	**-10.1**	**-47%**
Non Core (Modelling Assumptions)								
HILP	0.0	4.1	-	4.1	0.0	0%	4.1	-
BT21CN	3.5	27.8	700%	27.8	0.0	0%	24.3	700%
CNI security	0.0	6.0	-	6.0	0.0	0%	6.0	-
Black Start Capability	0.0	1.0	-	1.0	0.0	0%	1.0	-
Rising mains	0.3	21.3	7507%	21.3	0.0	0%	21.0	7507%
Total	**3.8**	**60.2**	**1503%**	**60.2**	**0.0**	**0%**	**56.4**	**1503%**
Total Baseline	**389.1**	**630.2**	**62%**	**553.8**	**76.4**	**12.1%**	**164.7**	**42%**

Table 24 Asset Replacement - Asset Specific Adjustments

SP Manweb £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
33 KV CB (ID)	16.3	5.2	11.1	2.9	8.2
LV Main (UG Plastic)	45.7	34.7	11.0	0.0	11.0
132kV Fittings (Tower Line)	4.7	2.3	2.4	2.4	0.0
132 kV CB (ID & OD)	19.5	17.3	2.2	2.2	0.0
6.6/11 kV CB (GM) Distribution	2.9	1.3	1.6	1.6	0.0
6.6/11 kV RMU	13.9	12.7	1.2	1.2	0.0
132 kV Transformer	9.6	8.7	1.0	0.0	1.0
LV Pillar (ID)	2.2	1.4	0.8	0.8	0.0
33kV UG Cable (Non Pressurised)	7.1	6.6	0.5	0.5	0.0
Cut out Replacement	1.4	0.9	0.4	0.4	0.0
6.6/11 kV Transformer (GM)	1.9	1.7	0.1	0.1	0.0
6.6/11kV UG Cable	8.3	8.3	0.1	0.1	0.0
LV Pillar (OD)	0.4	0.4	0.0	0.0	0.0
Total	133.9	101.5	32.4	12.3	20.1

SSE Hydro

Table 25 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

SSE Hydro								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	16.5	16.7	1%	16.7	0.0	0%	0.2	1%
Diversions	2.2	4.0	82%	2.2	1.8	46%	0.0	-1%
Reinforcement	22.7	19.5	-14%	18.4	1.1	6%	-4.3	-19%
Fault Levels	0.1	2.0	1900%	2.0	0.0	0%	1.9	1900%
Asset Replacement	118.1	151.2	28%	142.2	9.0	6%	24.1	20%
Operational IT&T	1.9	9.8	416%	8.6	1.2	12%	6.7	353%
Legal and Safety	3.5	11.0	214%	9.4	1.6	14%	5.9	169%
Total	**165.0**	**214.2**	**30%**	**199.5**	**14.7**	**6.9%**	**34.5**	**21%**
Non Core (Baseline)								
Flooding	0.0	2.7	-	1.3	1.3	50%	1.3	-
QoS (IIS)	7.4	0.0	-100%	0.0	0.0	0%	-7.4	-100%
QoS (Non IIS)	0.0	0.0	-	0.0	0.0	0%	0.0	-
Environmental	3.5	1.0	-70%	1.0	0.0	0%	-2.5	-70%
Losses	0.0	0.0	-	1.0	-1.0	0%	1.0	-
Total	**10.9**	**3.7**	**-66%**	**3.4**	**0.3**	**9%**	**-7.5**	**-69%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	0.0	-	0.0	0.0	0%	0.0	-
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	6.0	-	6.0	0.0	0%	6.0	-
Rising mains	1.4	1.5	7%	1.5	0.0	0%	0.1	7%
Total	**1.4**	**7.5**	**436%**	**7.5**	**0.0**	**0%**	**6.1**	**436%**
Total Baseline	**177.3**	**225.4**	**27%**	**210.4**	**15.0**	**6.7%**	**33.1**	**19%**

Table 26 Asset Replacement - Asset Specific Adjustments

SSE Hydro £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
6.6/11 kV CB (GM) Primary	8.8	8.2	0.6	0.6	0.0
Service Replacement	1.5	1.2	0.3	0.3	0.0
LV Main (UG Plastic)	1.5	1.2	0.3	0.3	0.0
6.6/11kV UG Cable	1.0	0.9	0.1	0.1	0.0
Total	12.8	11.5	1.3	1.3	0.0

SSE Southern

Table 27 - Detailed breakdown of DNO forecast for DPCR4 and Ofgem's Baseline proposals of Network Investment

SSE Southern								
DNO £m (07/08 prices)	DPCR4 actuals	DPCR5 Forecast	Increase (%)	Baseline	Reduction	Reduction (%)	DPCR4 - Baseline	DPCR4 - Baseline (%)
Core								
Demand Connections	24.7	58.8	138%	58.8	0.0	0%	34.1	138%
Diversions	4.9	19.0	288%	11.7	7.4	39%	6.8	138%
Reinforcement	169.3	150.2	-11%	142.5	7.7	5%	-26.8	-16%
Fault Levels	1.2	4.3	258%	4.3	0.0	0%	3.1	258%
Asset Replacement	293.3	369.3	26%	326.1	43.2	12%	32.8	11%
Operational IT&T	1.7	18.9	1012%	16.5	2.4	13%	14.8	872%
Legal and Safety	4.7	33.0	602%	8.0	25.0	76%	3.3	70%
Total	**499.8**	**653.5**	**31%**	**567.8**	**85.7**	**13.1%**	**68.1**	**14%**
Non Core (Baseline)								
Flooding	0.0	9.0	-	4.5	4.5	50%	4.5	-
QoS (IIS)	14.6	17.7	21%	0.0	17.7	100%	-14.6	-100%
QoS (Non IIS)	0.0	0.0	-	0.0	0.0	0%	0.0	-
Environmental	1.0	2.0	100%	2.0	0.0	0%	1.0	100%
Losses	0.0	0.0	-	4.1	-4.1	0%	4.1	-
Total	**15.6**	**28.7**	**84%**	**10.6**	**18.0**	**63%**	**-5.0**	**-32%**
Non Core (Modelling Assumptions)								
HILP	0.0	0.0	-	0.0	0.0	0%	0.0	-
BT21CN	0.0	0.0	-	0.0	0.0	0%	0.0	-
CNI security	0.0	0.0	-	0.0	0.0	0%	0.0	-
Black Start Capability	0.0	8.0	-	8.0	0.0	0%	8.0	-
Rising mains	3.3	5.0	52%	5.0	0.0	0%	1.7	52%
Total	**3.3**	**13.0**	**294%**	**13.0**	**0.0**	**0%**	**9.7**	**294%**
Total Baseline	**518.7**	**695.2**	**34%**	**591.5**	**103.7**	**14.9%**	**72.8**	**14%**

Table 28 Asset Replacement - Asset Specific Adjustments

SSE Southern £m (07/08 prices)	DPCR5 Forecast	Baseline	Reduction from DNO Forecast		
Asset			Total	Unit Cost	Volume
LV Main (UG Plastic)	49.0	35.1	13.9	13.9	0.0
132kV OHL Conductor (Tower Line)	21.2	17.8	3.5	1.9	1.5
6.6/11 kV CB (GM) Primary	29.5	27.5	2.0	2.0	0.0
132kV Fittings (Tower Line)	2.1	0.9	1.2	1.2	0.0
6.6/11kV UG Cable	14.3	13.1	1.2	1.2	0.0
132kV UG Cable (Non Pressurised)	7.4	6.3	1.1	0.0	1.1
Service Replacement	1.0	0.8	0.2	0.2	0.0
66 KV CB (ID & OD)	0.7	0.6	0.1	0.1	0.0
LV Pillar (OD)	0.5	0.5	0.0	0.0	0.0
Total	125.7	102.5	23.3	20.7	2.6

Appendix 8 - DNO Network Investment Outputs and Narratives

1.127. Each of the DNOs has now provided us with a comprehensive set of outputs data applying the common methodology set out in Chapter 17 of the 'Incentives and Obligations' document. The DNOs' initial output proposals are published on the Ofgem website alongside Initial Proposals.[7] These data reflect the DNOs' views on the outputs to be delivered by their proposed level of network investment over DPCR5. We have not amended the DNOs' proposed outputs to reflect our draft network investment allowances for Initial Proposals.

1.128. There will be an ongoing process between Initial and Final Proposals to ensure that the volumes underpinning the DPCR5 allowance for network investment on general reinforcement and asset replacement fully reconcile with and are supported by the network outputs. This reconciliation process may necessitate an update in autumn for the outputs data.

1.129. Each of the DNOs has been provided the opportunity to submit a one-page narrative with their views on the development of network output measures for DPCR5. These are included below.

1.130. In this section we have also included some guidance for stakeholders to view the outputs spreadsheets published with Initial Proposals.

[7] The DNOs' outputs spreadsheets are provided as an attachment to the 'Allowed Revenue and Cost Assessment' document, at the following link: http://www.ofgem.gov.uk/NETWORKS/ELECDIST/PRICECNTRLS/DPCR5/Pages/DPCR5.aspx

Central Networks (CN)

1.131. Central Networks has been very active in the development of a range of outputs that attempt to demonstrate the current condition and capacity of the network and the impact our investment plans will have. We believe that a clearly defined and transparent range of output measures will help to clarify and monitor the benefits of distribution network investment programmes to stakeholders.

1.132. The Methodology Paper correctly acknowledges that this is the first time such structured outputs have been used as part of the regulatory framework. Whilst historically network load, asset condition and asset age data has provided an understanding of the current network, the construction of a finite number of more complex indicators against which to assess investment has been challenging. In deriving these forecasts of asset condition and network loading over DPCR5, we have used existing network data supplemented by a range of assumptions:

- To produce the required load indices, we have forecast changes in demand at substation level by combining long term site-specific summer and winter demand trends with known and forecast connection activity.
- We are continuing the development and refinement of the health indices that inform asset replacement and inspection and maintenance activities, and have used existing information for many of the asset classes. Where these are not yet sufficiently robust other indicators of asset condition such as age or design criteria have been incorporated. This data has been modelled using asset degradation assumptions to produce an assessment of asset condition forecasts for the DPCR5 period.

1.133. In general the DPCR5 investment proposals are seeking to maintain current risk levels. However in some cases, even with the proposed increased levels of investment, the output measures suggest a need for a continuing upward trend in investment in DPCR6 and beyond.

1.134. Given the speed of development of this regulatory process and its inevitable lack of maturity, it is important that a formal change mechanism is developed to revise output targets in response to changing circumstances and data. We also look forward to building on this approach in DPCR5 to further enhance the justification for and monitoring of investment in subsequent price controls.

1.135. In summary, progress has been rapid. This process is in its infancy and the links between outputs and their associated investment levels will not reliably support the systematic assessment of DNO performance during DPCR5. However, we believe we have identified an enduring approach to monitor and justify investment and network risk in future price control reviews.

Electricity North West (ENW)

1.136. We are supporters of the move to greater transparency on outputs and have worked with Ofgem to develop the current framework. In particular, we have been at the forefront of developing Health Indices for our assets over the last few years as a means of prioritising investment based on condition and assessing the current and future risk from our assets. The DPCR5 framework that has been developed remains an immature one in several important areas, and one that requires significant future development. We are happy to commit to developing the template and work towards 'Tier One' output measures with Ofgem in the DPCR5 period.

1.137. In terms of the output levels proposed in our submission, these are essentially predicated on maintaining the stability of the underlying asset base, both in terms of its level of performance and ability to serve the needs and demands of our customers. This will need to be achieved in the face of an ageing infrastructure base and changes in customers' requirements due to the economic environment, new energy policy imperatives, climate change effects etc.

1.138. With regards to the existing asset base, our fundamental strategy is to maintain the integrity, security and safety of the electricity distribution network, by replacing assets when they reach the end of their serviceable life, and refurbishing assets to extend their life (where appropriate) to maintain a generally static background risk against service failure. This level of risk will in the main be achieved by managing those assets in worst condition and maintaining overall asset fault rates at about their current stable levels, despite an ageing asset base. For DPCR5, we forecast that this stability will require a further incremental rise in asset replacement requirements with the retirement of many of the assets installed due to the significant load growth and rural electrification programme of the 1950/60s. Some assets, such as overhead lines in particular, are now known to require significant investment to comply with changed legal requirements, as well as an increasing programme of replacement based on condition.

1.139. In spite of overall falling demands and the effects of the recession, there remain areas of highly loaded network and significant customer demands for new supplies, particularly in urban regeneration areas. Highly loaded networks present particular risks to customers both in terms of our ability to provide timely new connections and also service failure arising from any ENW asset failure. We also anticipate that urban and suburban areas could see some significant load growth caused by the decarbonisation of heat and transport (or at least the start of it) and we wish to continue to refine our collective approach to outputs in this area such that the risks to customers are properly recognized and managed.

1.140. Our output projections are consistent with our investment forecasts and are based on the most accurate and current information we have. We will continue to make improvements in data capture and assessment techniques and calibrate our models with the observed effects of investment to further refine our projections in the DPCR5 period.

CE Electric UK (CE)

1.141. Overall, we are supportive of the use of output measures and remain committed to working with Ofgem to develop these outputs further over DPCR5. The output measures themselves will enable Ofgem to confirm the effectiveness of the implemented investment provided that potential changes in the output measure mechanics and valid reasons for variances in performance such as new risks over the period are adequately captured. In this manner we believe the most appropriate use of outputs is as a set of indicators to establish whether or not the DNO has delivered financial outperformance at the expense of good stewardship

1.142. The Ofgem templates for substation load indices, asset health indices and fault rates have been completed in line with the Ofgem methodology and guidance. The process followed has been to extract actual data on our assets and then forecast future positions taking into consideration assumptions on asset degradation, load growth and the consequences of our forecast investment plans submitted in June 2009.

1.143. Many of the decision support tools used to produce the asset health indices have been developed in recent years. We therefore welcome Ofgem's recognition that these indices are in their infancy and will need to evolve further over DPCR5 especially with regards to assumptions on asset degradation and forecast performance.

1.144. We believe that the output measures should be viewed in a holistic way as the asset manager will seek to trade-off outputs in order to achieve a balance between cost, risk and performance. Importantly it should be recognised that assets assigned to bands HI4, HI5, LI4 and LI5 will be managed via more regular inspections, enhancement maintenance, partial refurbishment or complete asset replacement as deemed necessary by the nature of the underlying potential failure cause and the consequence of failure.

Western Power Distribution (WPD)

1.145. The network output measures presented by WPD for Year 0 provide an indication of overall asset health, condition, performance and utilisation as at 1st April 2010. The Year 0 data is underpinned, in the vast majority of instances, by actual observations in respect of asset condition and asset utilisation.

1.146. The network output measures presented by WPD for Year 5 are a forecast of overall asset health, condition, performance and utilisation as at 31st March 2015. In broad terms, WPD's objective for the period 2010 to 2015 is to maintain overall asset health, condition, performance and utilisation at their current prevailing levels.

1.147. The forecast Load Indices for Year 5 take into account our current view of the forecast change in demand in the period 2010 to 2015. The actual change in demand in that period will be influenced significantly by economic conditions.

1.148. The forecast Health Indices for Year 5 take into account our current view of the rate of degradation of asset condition.

1.149. Network output measures are in the early stages of development. WPD is committed to refining and developing these output measures independently and in conjunction with Ofgem.

EDF Energy (EDFE)

1.150. EDF Energy believes that the development and use of Output Measures can be a useful tool to complement asset management best practice and to reassure customers that DNOs are placing appropriate focus on long term asset capability.

1.151. Our Load Index (LI) output measures build on our detailed load estimating processes and represent our current best view of the effect on asset utilisation of future load movements based on the development of the underlying economic variables.

1.152. Our Health Index (HI) output measures represent our current best view of the future condition of our assets. We have taken our present understanding of a range of factors to derive a plan for maintenance and replacement that keeps risk broadly at current levels. The factors include known asset condition, an estimate of how that condition is likely to degrade over time, the impact of asset failure on our statutory obligations (including safety and environmental obligations), the number and duration of customer interruptions, and the cost of projects to recover poor asset condition. It is important to note that some of these factors cannot be expressed in the current form of HI measures.

1.153. A material change to any one of our key underlying assumptions is likely to change the way we efficiently manage overall network risk. More specifically, it would mean that different projects would be needed to those indicated in our FBPQs, and whilst the overall network risk would remain broadly the same as indicated for 2015, the out-turn value of measures for specific asset types may vary from those forecast – with changes in both directions (i.e. some assets types are in a better condition than indicated, and some are worse).

1.154. It is our understanding that if any of these changes results in a broadly similar network risk at a lower cost then those cost reductions will be viewed as a legitimate efficiency saving by EDF Energy. This is consistent with Ofgem's stated desire to use output measures to focus on customer outcomes, and to incentivise DNOs to provide those outcomes efficiently.

1.155. Output measures are at an early stage of development and EDF Energy is concerned that expectations placed on the current forecasts may be inappropriate. We consider that the Output Measures project is comparable to the introduction of the Quality of Service Incentive Scheme which took some three years of collaborative development before the present process was fully embedded. It is important that the framework is sufficiently flexible to allow the arrangement to bed-down without creating inappropriate financial risks for DNOs.

Scottish Power (SP)

Development of Output Measures

1.156. Scottish Power are supportive of the development of output measures in the areas of asset replacement and general reinforcement. We proposed a range of investment level, tier two, output measures in our February FBPQ submission and have refined these output measures recently against a common methodology which has been developed with Ofgem and the other DNOs.

1.157. The network output measures developed as part of the DPCR5 settlement must be suitable not only for Ofgem in determining whether customers receive value for money, but also as a useful internal planning and management tool for the DNOs themselves. We support the further development of output measures for DPCR6 including whether or not a suitable common network level, tier one, measure can be achieved.

Agreement of Targets and Reviewing Performance

1.158. Through the DPCR5 process Scottish Power will agree a set of output measure targets with Ofgem. These targets are directly linked to our proposed investment plans in the areas of asset replacement and general reinforcement.

1.159. Agreement of the targets is inherently linked to alignment of three key areas. The proposed volume of work for DPCR5, the scope of work and efficient cost in each area and appropriate treatment of input cost uncertainty. Agreement of these three elements will allow the output measure targets to be confirmed.

1.160. The proposed output measures are linked to the overall investment level and mix. The mechanism for reviewing performance against output measures needs to allow flexibility for DNOs, based on their view of risk, to prioritise investment, and therefore the associated outputs, to deal with new information and unforeseen events. The output measures and targets should be viewed as a group of measures rather than individual measures and targets.

1.161. The use of output measures for asset replacement and general reinforcement is still in its infancy and further improvement is expected and encouraged over the course of DPCR5. In reviewing performance against output measures account should be taken of how measures have been developed and its impact on the agreed targets. The review must also ensure that DNOs are not penalised for differences between forecast and predicted load growth.

1.162. Based on agreement of an appropriate reporting mechanism we believe that the proposed output measures will demonstrate our delivery associated with the DPCR5 settlement.

Scottish and Southern Energy Power Distribution (SSE)

1.163. Scottish & Southern Energy are supportive of the principle of output measures, they provide the evidence that investment has been effective and proportionate to the role and condition of individual assets. They have the potential to provide the basis of a "charter".

1.164. The measures gathered are a good starting point for what is an ambitious aim one not previously achieved within the industry. Our main concern is that these emerging measures become locked into the price review process in such a way that their development as objective measures is inhibited and flexibility lost.
To address this concern we expect the role of output measures in DPCR5 to be an evolutionary process subject to iteration and development throughout.
We believe following this period of development they will play a significant role informing internal management and external stakeholders in the future.

1.165. A significant concern we have is that if applied badly output measures could inadvertently be used to encourage all DNOs to adopt the same solution to problems, this if allowed to happen would stifle innovation in times when the industry needs to nurture a broad range of solutions to improve efficiency, environmental, safety and other objectives.

1.166. In producing these measures we have found three areas that warrant further work at an early stage in DPCR5:

1. Asset data collection for low cost high volume equipment would benefit from improved asset data collection to ensure that the value of and cost of gathering data can be optimised. We have started work on improved field data gathering to this end.
2. Establishing current health indices is on the whole simple; the challenge is to predict the rate of degradation of assets at a level that does not result in excessive and expensive monitoring and analysis, to this end we have commissioned work with University of Strathclyde to build on work started last year.
3. Certain measures do not fit with the way we do business e.g. SSEPD has completed the pole condition OM based on a very basic extrapolation of field data, the principles SSE apply to rotten poles is to assess residual strength "fit for purpose" and if appropriate manage rot through treatments. As part of our 12 year overhead line refurbishment programme we systematically rectify all defects in a section of line, counting this work by km refurbished rather than counting individual defects restored. This approach has been key to our historically low cost of refurbishment, requiring minimal data collection and single site visits to complete a section of line.

Outputs spreadsheets - guidance for stakeholders

1.167. This section provides stakeholders with some brief guidance for viewing the DNO's' proposed outputs in the Excel files published alongside Initial Proposals. Each section below refers to a separate sheet within the outputs workbook.

Version & Contents

1.168. This sheet provides and links to each of the worksheets, as in Table 1 below.

Table 1: Contents of Outputs workbook

Area	Table
Load Index (LI)	LI Logic
	LI data
	LI charts
Health Index (HI)	HI data
	HI charts
Fault rates	Fault rate data
	Fault rate charts
Asset volumes	Volume reconciliation

LI Logic

1.169. This sheet provides the individual DNO's decision criteria for assigning sites a Load Index ranking LI1 to LI5 in accordance with the agreed common definitions. The allocation of sites to LI bands is based upon the level of and interaction between the following drivers for a site-specific demand-related intervention:

- Demand driver: measure of site maximum demand relative to site firm (n-1) capacity, and
- Duration driver: measure of the hours / energy at risk brought about by the capacity utilisation at the site.

1.170. To recognise differences between individual DNOs (e.g. definitional, data quality, level of initial network risk), each of the seven DNOs has been allowed to define their own unique thresholds for assigning sites an LI band 1-5.

1.171. Table 2 below provides an example of a set of DNO decision criteria for establishing an LI profile.

Table 2: Example - Description of LI Logic

	Demand driver	Duration driver
LI1	0-90%	N/A
LI2	90-95%	N/A
LI3	95-103%	<9 hours
LI4	95-103%	>9 hours
	>103%	<9 hours
LI5	>103%	>9 hours

1.172. For example, this DNO will assign a specific site to LI4 ('Fully utilised, mitigation requires consideration') if:

- The site maximum demand represents 95-103 per cent of firm (n-1) capacity, and the duration of maximum demand over firm in a given year is greater than 9 hours, OR
- The site maximum demand represents greater than 103 per cent of firm (n-1) capacity, and the duration of maximum demand over firm in a given year is less than 9 hours.

1.173. The LI Logic sheet contains a series of VLOOKUP tables which feed the DNO's decision criteria through to the LI data sheet.

LI data

1.174. The LI data sheet contains the full set of input data used to generate the LI profile for each substation or interconnected substation group:

- at the start of DPCR5 (i.e. 'column L') – this reflects the current capacity utilisation of the network,

- forecast at the end of DPCR5 with no intervention (i.e. 'Column Y') – this will reflect the impact of forecast load growth at each site over DPCR5, and
- forecast at the end of DPCR5 with investment (i.e. 'Column AE') – this will reflect the DNO's view on how the current LI profile will be impacted by the proposed level of DPCR5 investment in general reinforcement, or any other forecast intervention (e.g. manual transfers).

LI charts

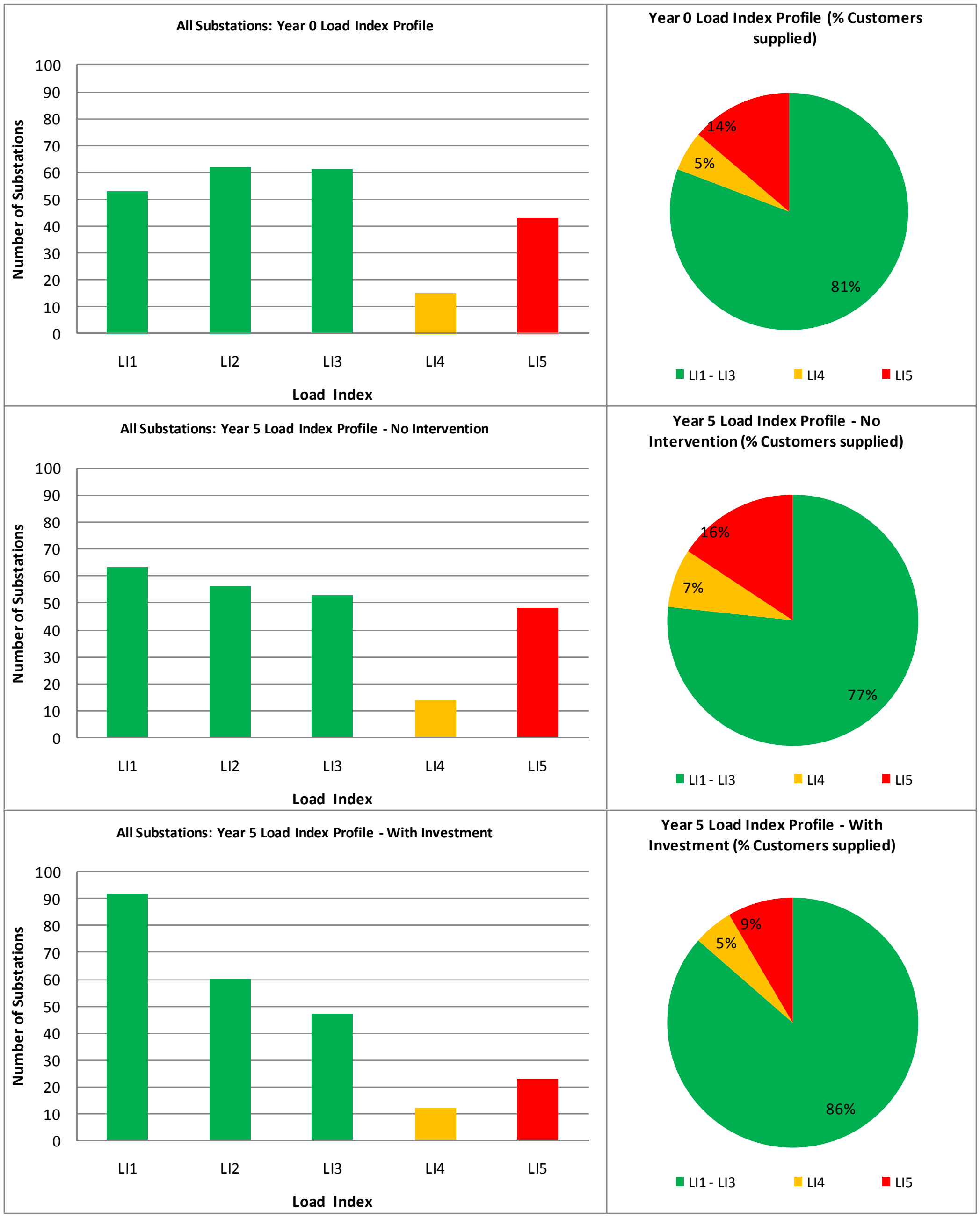
1.175. The LI charts sheet contains a series of buttons which when pressed produce charts with an LI profile for the following categories:

- All substations,
- Substations (132kV primary to EHV secondary),
- Substations (EHV primary and secondary),
- Substations (EHV primary to HV secondary),
- Substations (132kV primary to HV secondary), and
- Substation Groups.[8]

1.176. Figure 1 below provides an example of an LI chart.

[8] While Ofgem intends to explore using the LI profile for transmission exit points to help inform an understanding of forecast transmission exit charges, DNOs were not required to report an LI profile for transmission exit points for Initial Proposals.

Figure 1: Example of LI chart - ALL SUBSTATIONS



1.177. The LI charts produced represent the key output measures for general reinforcement that DNOs have committed to deliver over the course of DPCR5.[9]

HI data

1.178. The HI data sheet contains the full set of input data used to generate the HI profile for each substation or interconnected substation group:

- at the start of DPCR5 (i.e. Health Index - Year 0') – this reflects the DNO's view on the current health of the relevant assets,
- forecast at the end of DPCR5 with no intervention (i.e. 'Health Index - Year 5 with no intervention') – this will reflect the DNO's view on the rate of asset degradation over the period, and
- forecast at the end of DPCR5 with investment (i.e. 'Health Index - Year 5 with investment') – this will reflect the DNO's view on how the current HI profile will be impacted by the proposed level of DPCR5 investment in asset replacement, or any other forecast intervention (e.g. increased maintenance).

1.179. The section on HI data quality ('column T' onwards) describes, for each of the relevant asset classes, the following characteristics of the DNO's HI data:

- 'Number of assets included for HI output measure' (column T) - contains the number of assets in the DNO's asset register which have been assigned a HI ranking HI1 to HI5,
- 'Primary form of measure' (column U) - contains the measure used to generate the HI profile:

Health	usually combine both the observed condition and the operability (e.g. design issues, service history, availability of spares) of the asset in question, giving a overall indication of the present 'health' of the asset
Condition	measure based purely on the observed condition of the asset in question
Age	asset health is inferred based on the age of the asset in question relative to some estimate of its 'mean life'
Other	any other measure not included above

- 'Number of assets actually observed' (column V) - contains the percentage of assets assigned a HI ranking which have been the subject of an actual observation (i.e. size of sample),

[9] Note that the percentage of customers supplied by 'All substations' will add up to greater than 100 per cent of the DNO's customer base, as any given customer may be supplied by more than one substation (at different voltage levels).

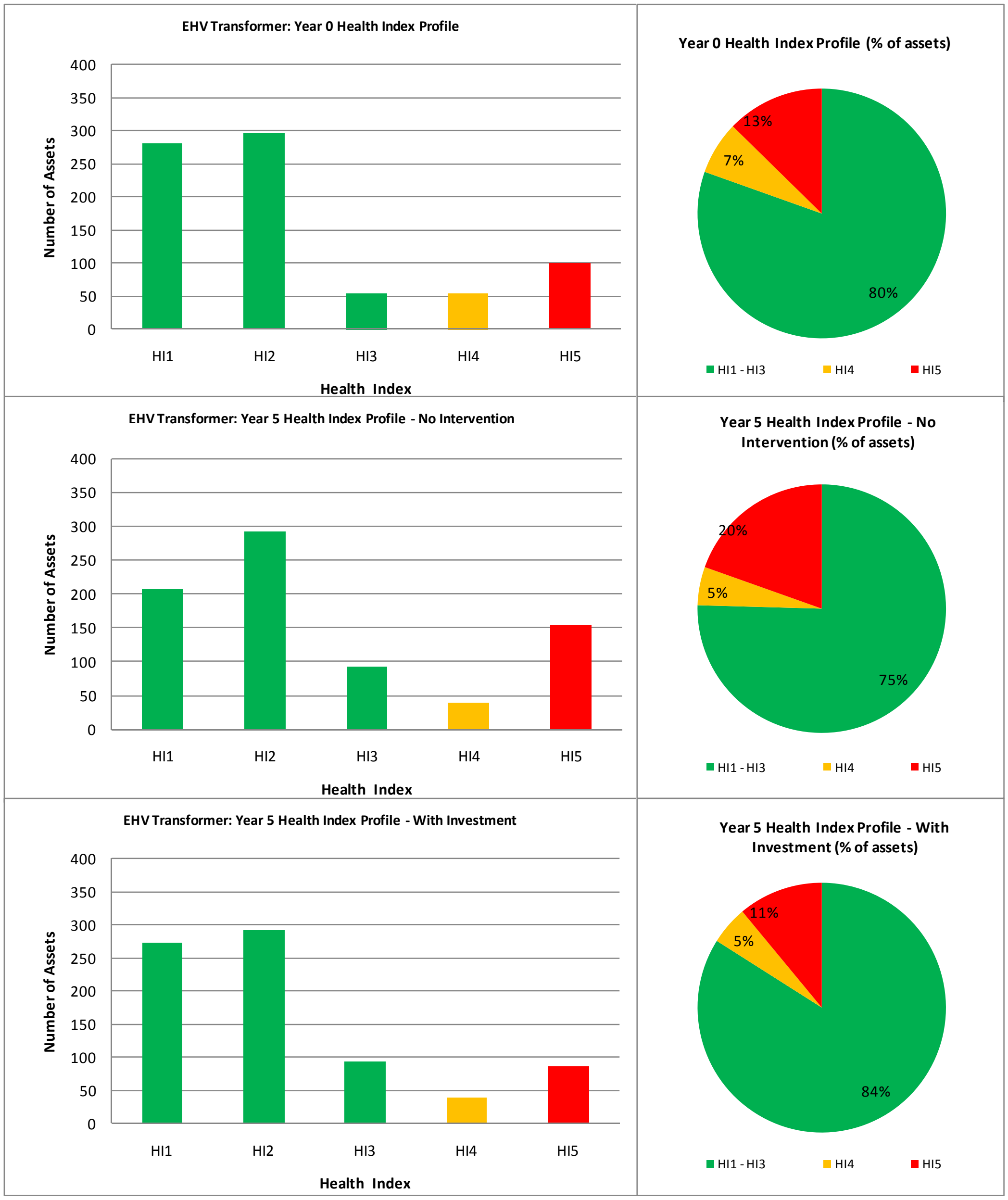
- 'Average age of data used' (column W) - contains the average age (in years) of the actual data used to generate the HI profile,
- 'Description of the form of measure used to assign a HI, the quality of data used, and any other relevant information' (column X),
- 'Degradation assumption adopted' (column Y) - describes the assumptions adopted by the DNO to forecast the Year 5 HI profile.

HI charts

1.180. The HI charts sheet contains a series of buttons which when pressed produce charts with a HI profile for each of the 23 agreed asset categories.

1.181. Figure 2 below provides an example of a HI chart, for the asset category 'EHV Transformer'.

Figure 2: Example of HI chart - EHV Transformers



1.182. The HI charts produced represent the key output measures for asset replacement that DNOs have committed to deliver over the course of DPCR5.

Fault rate data

1.183. The fault rate data sheet contains historical (2001-02 to 2008-09) and forecast (2009-10 to 2014-15) fault rates for each of the 16 agreed asset categories (where applicable). Fault rate data is provided against each of the following categories:

- Total faults,
- Total faults excluding exceptional events,
- Damage faults, and
- Damage faults excluding exceptional events.

Fault rate charts

1.184. The fault rate charts sheet contains a series of buttons which when pressed produce charts with a rolling average fault rate for each of the 16 agreed asset categories.

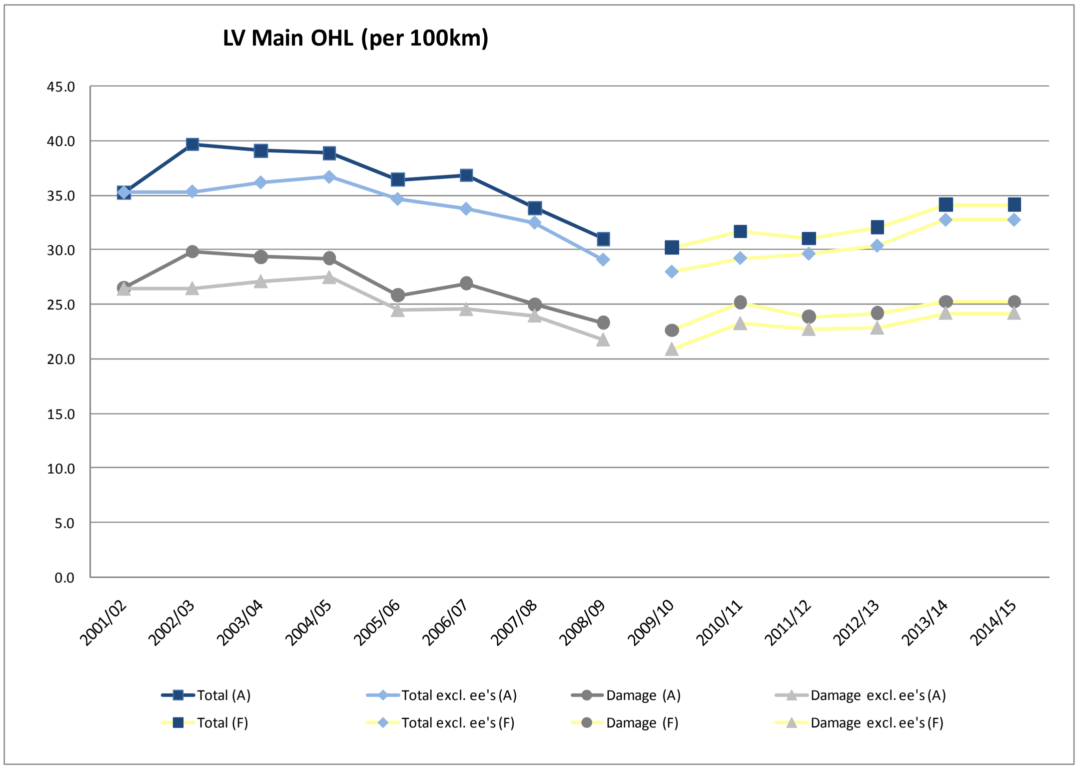
1.185. The sheet produces charts with:

- all the fault rate data for the given asset class, and
- data for damage fault rates only.

1.186. The agreed output measure for fault rates is total damage faults (i.e. including exceptional events).

1.187. Figure 3 below provides an example of a Fault rate chart, for the asset category LV Mains Overhead Lines ('LV Mains OHL').

Figure 3: Example of Fault rate chart - LV Main OHL



1.188. For DPCR5, fault rates will be used as a secondary network output measure for asset replacement expenditure, for specific asset classes where:

- the DNO does not presently have HI capability, and/or
- it is not economic to collect a full set of HI data.

Volume reconciliation

1.189. This sheet contains a summary of the asset volumes included in the agreed HI and Fault rate asset categories.

Appendix 9 - Electricity Distribution Price Control Methodology Paper - Melvyn Weeks, Faculty of Economics and Clare College, University of Cambridge

Section 1 - Introduction

1.1. In DPCR5 the estimation of efficiency at the level of individual DNOs is an important input into the price review process. In general terms this is done by undertaking a comparison across DNOs with the objective being the determination of an efficient level of cost allowances for DNOs to carry out their activities. In this document we consider the approach adopted in DPCR5 against a backdrop of previous price control reviews. For the first electricity distribution price control review (1990/91 -1994/95), network charges were set while the DNOs were under state control. For the second and third price controls (i.e. 1995/96-1999/00 and 2000/01-2004/05 periods respectively) Ofgem applied the corrected ordinary least squares (COLS) technique for benchmarking of the DNOs' operating expenditures.10 The regression model comprised the use of normalised operating costs as the dependent variable and a composite scale variable.11 The COLS estimator was also used for the fourth price control review; DEA was used as an alternative for the purpose of cross checking (OFGEM (2004)). Similarities were found between the results of both techniques (Cambridge Economic Policy Associates (2003b)).

1.2. In previous price reviews comparative benchmarking has been conducted utilising a single year's data per DNO, and a combination of model-based inference alongside regulator judgement, the latter informed by a process of dialogue with individual DNOs. In the context of the specific problem faced by Ofgem -namely a limited set of measured cost drivers and fourteen comparators -a regulator can intervene, either pre or post estimation to make adjustments to either the raw data and/or the estimated residuals. These adjustments can take a number of forms, and include adjustments for DNO-specific factors. This type of regulator intervention represents one way of accounting for unobserved DNO-specific costs factors, and thereby identifying firm-specific efficiencies, with cross-section data.

1.3. Of late the Competition Commission and a number of regulators (including the Office of Rail Regulation (ORR)) have advocated a panel-based approach to relative efficiency analysis. One advantage of this methodology is that, in certain instances, it offers the potential to internalise certain adjustments (e.g. company specific factors) and thereby utilise a model-based approach to identification. Ofgem now has access to four years of comparable data for the period 2005/06 to 2008/09. This affords the possibility to better differentiate firm-specific inefficiency from a number of factors which will generate variation in costs across DNOs, such as unobserved DNO-specific

10 See Pollitt (2005) and Jamasb and Pollitt (2007) for a review of the UK's distribution price control reviews and benchmarking procedures.
11 The composite scale variable is constructed as a weighted mean of customer numbers, network length, and units of energy delivered.

factors (which are outside the control of the firm), and scale efficiency. However, given the small number of time series observations per firm, it is still the case that the task of isolating an efficiency component requires a combination of econometric techniques and regulator intervention. The relative contribution of model-based and regulator knowledge will obviously depend upon a number of factors including the nature of the available data. However, as Sickles (2005) notes "*it is indeed difficult to identify firm-specific and time varying efficiencies and that a strong institutional understanding of the industry under study is crucial to determining which estimator should be used*".

1.4. The remainder of this document is structured as follows. In section 2 we provide a general overview of the benchmarking approach adopted by Ofgem in DPCR5. Sections 3 and 4 considers a number of specific issues with benchmarking. In section 3 we focus on a number of issues relating to decisions that are required prior to model estimation, including the comparability of costs, the potential distortionary effects of cost boundaries and the relative merits of top down versus bottom-up approaches. In previous price reviews Ofgem has set prices based upon a single year of data, whereas at this juncture it is now possible to conduct costs comparisons over multiple years given the standardisation of data. Subsequently, in section 4, we outline a number of benchmarking issues related to the use of panel data.

1.5. In section 5 we discuss a number of issues that relate to the way in which estimates of inefficiencies are translated into price allowances. Specifically, we consider the question as to where to set the benchmark, the estimation of interval estimates for the efficiency scores, and related the potential for utilising efficiency bands.

Section 2 - Ofgem Approach

1.6. In this section we outline the modelling approach adopted by Ofgem with respect to a number of key areas. These are the choice of the estimator, the balance of top-down and bottom-up benchmarking, the choice of cost drivers, the precision of parameter estimates, and the choice of the benchmark. We also outline a number of alternate approaches that have been considered. We emphasise that in this section we provide an overview of the approach to benchmarking adopted in DPCR5. In sections 3 and 4 we consider a number of issues that underlie and have informed the methodological approach adopted by Ofgem. In section 5 we discuss a number of key issues relating to the uncertainty attached to the point estimates of the efficiency scores

1.7. In DPCR5 Ofgem utilise a panel data methodology in combination with regulator judgement. The approach utilises the panel structure of the data to separate technical efficiency from technical change. Given the small number of time periods, data adjustments are used to control for DNO-specific effects. The econometric model is then used in conjunction with regulator judgement to set the efficiency benchmark, and estimate firm-specific efficiency scores.

1.8. **Remark 1** *The process of price cap regulation adopted by Ofgem represents a combination of both econometric estimation and a number of regulator interventions based upon institutional knowledge and consultation with individual DNOs. The basis for such regulator intervention is a belief that in conjunction with a particular model, the data alone are not sufficient to estimate DNO-specific efficiencies. As considered below, examples of regulator intervention include adjustments for DNO-specific factors, the selection of an appropriate benchmark, and the banding of the efficiency distribution. These interventions are motivated by the uncertainty attached to the estimates of firm-specific inefficiency following concerns over data availability and quality, and more generally in terms of the most appropriate econometric model. A specific example of regulator intervention is the manner in which DNO-specific factors are accounted for. This type of regulatory intervention follows from the acknowledgement that the observed set of cost drivers which determine predicted costs may exclude one or more DNO-specific factors. These factors reflect circumstances that are outside of the control of the companies and affect costs, but are not covered by the standard cost drivers.*

1.9. Both in terms of the econometric model and testing, and the set of regulator interventions, Ofgem, in part responding to criticism received after the publication of the May document, has sort to make the process transparent. In Appendix 5 Ofgem presents the reader with a how-to guide to estimate efficiency scores at the level of the DNO.

Section 2.1 - The estimator

1.10. In utilising regression analysis the estimator used by Ofgem is pooled ordinary least squares (OLS) with dummies for the time effects. An estimator which provides estimates of DNO-specific fixed effects was also considered. However, the chosen approach has been to use the process of regulator-DNO dialogue to adjust for DNO-specific differences. There is a trade-off here in terms of transparency and replication. If, for example, fixed effects (DNO dummies) are included, then this facilitates ease of replication. However, the adjustment for DNO-specific effects through dialogue is, in this instance, preferred since there is greater transparency from the perspective of the DNOs. It is also the case that in small samples the estimated fixed effects can contain substantial noise and as such the reliability of model-based fixed effects requires a longer time series than our four years.

Section 2.2 - Functional form

1.11. In many empirical applications generally, and efficiency analysis in particular, the most common functional forms are the linear and log-linear specifications, with the latter based on log transforms of both the dependent and explanatory variables. In initial analyses Ofgem utilised both linear and log-linear specifications and observed that the log-linear model demonstrated a higher degree of correspondence with the results from alternate estimators, including DEA. In general terms there are a number of advantages of the log-linear specification, including the flexibility to accommodate non-linear relationship between the dependent and independent variables. In the context of efficiency analysis, one particular advantage of the log-linear specification is that it allows for economies of scale. This is obviously important given the considerable variation in scale across electricity distribution companies in the UK. Evidence of this is revealed in the range of the Modern Equivalent Asset Value: £3.6 billion for SSE-Hydro and £10.6 billion EDFE LPN.

1.12. Similarly, when calculating efficiency scores utilising data envelopment analysis Ofgem's preferred frontier has been the variable returns to scale (VRS) frontier. The reason for this, relative to the use of a constant to scale (CRS) frontier, is that whereas CRS embodies the impact of both technical efficiency and scale efficiency, VRS removes the effect of scale.

1.13. **Remark 2** *We note that there is one disadvantage in using the log model, related to the calculation of predicted costs in original units. Based on the use of the OLS estimator we can predict the log of costs for each firm. However, it can be shown that simply exponentiating log C will systematically underpredict the expected costs. Ofgem has accounted for this problem using a simple adjustment which is outlined in Wooldridge (2006).*

Section 2.3 - Cost determinants

1.14. In the following discussion we make the distinction between adjustments to costs that are determined utilising regression methods, and adjustments that are undertaken prior to the estimation of model parameters.[12] The former adjustments are made utilising cost drivers with the actual effect of the cost driver unknown and then estimated. In this context the use of an OLS estimator can be used to predict average costs for firms with a given set of characteristics (cost drivers).

1.15. Although in the estimation of firm efficiencies Ofgem is utilising panel data, both the cross-section and time series dimensions are limited. Initial analysis was based upon three observation per DNO, and recently another year has been added with the inclusion of data for 2008/09. The nature of the data will obviously determine both the econometric method that is used to isolate efficiency from other components of cost, and both the adjustments for DNO-specific factors and the choice of cost drivers (sections 2.5 and 4 for further discussion).

Section 2.3.1 Normalisation adjustments

1.16. Normalisation adjustments facilitate the comparison of DNO costs on a more equitable basis. These adjustments are used to determine the comparative efficiency scores and are not an adjustment to the baseline allowances. In the May document Ofgem highlighted a number of possible normalisation adjustments which included labour and contractor rates, recognition of indirect costs, sparsity etc. Ofgem have

12 We note that the discussion of cost determinants focuses solely on a number of econometric issues. A more complete discussion of is contained in Chapter 4 and Appendix 5 of the Ofgem Allowed Revenue Cost Assessment document.

undertaken further work to inform the choice normalisation adjustments and for the purposes of these proposals have made adjustments for:

- Labour and contractor rates;
- Non-operational capex;
- Recognition of indirect costs;
- Cable replacement;
- Interconnected network;
- sparsity;
- Urban working.

Section 2.3.2 - Cost drivers

1.17. As detailed in its Allowed Revenue Cost Assessment document, Ofgem has consulted extensively with DNOs to obtain a more complete understanding of the drivers of costs. As a result, relative to the analysis in the May document, there have been a number of significant changes with regards to the way in which Ofgem utilises cost drivers. These developments are summarised below and also presented in Tables 5 and 6 in Chapter 4 of the Ofgem document.

1.18. **Bottom-up** - As part of the consultation process, a number of drivers for each of the activities and activity groupings have been identified. Given the small sample size and the attendant problem of collinearity, two drivers for each of the activities were selected. For both direct and indirect costs a primary (indicated in bold) and a secondary driver were identified. For example, in the case of underground faults the primary driver is the number of faults and the secondary driver is the length of line/cable replaced.

1.19. **Composite Variable -** In undertaking bottom-up benchmarking Ofgem has adopted an approach which combines knowledge from the working groups as to what are considered the most important drivers, alongside the model-based weights (i.e. regression coefficients). Where a primary and a secondary driver has been identified from that work the weighting on the secondary driver is then capped. To accomplish this a composite variable is constructed.

1.20. **Regulator weights -** Based on this knowledge, and the relatively small sample, Ofgem has applied the following procedure in utilising the results of the bottom-up regressions. After standardising each cost driver by subtracting off its mean and dividing through by its standard deviation, the effects of each driver on the respective cost components are directly comparable, given the removal of scale effects. If the weight of the primary driver is less than the secondary equal weights (i.e. the beta coefficients) are assigned to each driver.

1.21. As stated, following a broad consultation with DNOs a number of cost drivers were identified for each activity, together with the distinction between primary and secondary drivers. In a number of instances Ofgem has intervened and imposed a different set of weights than generated by the regression model. This follows from strong priors as to the relative importance of these factors in determining costs. In such cases Ofgem has also examined the impact of this intervention on the results.

1.22. **Top Down Benchmarking -** In both the 1999 and 2004 DPCR Ofgem used a composite scale variable comprised of customer numbers, units distributed and network length. The reason for this approach is that with only 14 data points, the use of separate output measures is problematic especially given that these measures exhibit significant correlation. As Pollitt (2005) notes, Cambridge Economic Policy Associates (2003a) undertook analysis to determine whether there was a significant correlation between 1999 base operating costs and a range of alternate cost drivers, and found no statistically significant additional drivers.

1.23. Similar to bottom-up benchmarking, in the core regressions for DPCR5 Ofgem has utilised a primary and secondary driver for the top-down regression: the primary driver being Modern Equivalent Asset Value and the secondary driver the sum of load and non-load related expenditure.

Section 2.4 - Precision of estimates

1.24. The chosen estimator for the Core regressions is pooled OLS with time dummies. In estimating the precision of parameter estimates Ofgem has made adjustments for the panel structure of the data. Namely, although there are now a total of 56 observations (14 DNOs observed for 4 time periods), given that for each DNO we have 4 records which are likely to exhibit some form of dependence over time, it is necessary to adjust standard errors for this particular form of clustering. Given the increasing availability of panel data, robust covariance matrix estimators for panel data which allow for arbitrary within individual (here DNO) correlation are now available in standard software packages (see, for example, Arellano (1987)). One drawback of this estimator is that its properties are only known as the cross-section dimension, here the number of firms, increases with the time dimension fixed. Given that in this instance the cross-section dimension is fixed we note the findings of Hansen (2007), namely that for the cross-section dimension fixed and iid assumption across firms, the usual t and F statistics can be used for inference.

1.25. Ofgem has also recognised that the efficiency scores which are reported are point estimates. In section 5 we consider issues relating to the estimation of interval estimates for these quantities, and in more general terms, methods that allow the regulator to account for the uncertainty attached to these estimates.

Section 2.5 - Alternate approaches

1.26. Alongside the aforementioned panel data model Ofgem have also explored two additional approaches: Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA). These approaches differ in the assumptions that are used to separate inefficiency from other sources of error. DEA is a non-parametric linear programming technique that employs a minimal set of assumptions to construct the efficiency frontier and estimate DNO-specific technical efficiency. Unlike regression-based approaches there are no assumptions as to the functional form of the cost function, and given that there is no random error this approach is not subject to issues surrounding the distribution of the error term. However, a consequence of this is that DEA assumes that all distances from the frontier represent inefficiency; there is no account for measurement error or statistical noise. In order to remove the effects of scale efficiency, we use DEA to construct a variable returns to scale frontier.

1.27. In seeking to explore the potential for the estimates of inefficiency to be undermined by other sources of error, we have undertaken a preliminary analysis using SFA. SFA utilises the same specification for the cost function, but partitions the overall error term into a one-sided component representing inefficiency and a two-sided error component which represents random measurement error. The estimated frontier is now stochastic based on combining the location of minimum costs for the firm given the control variables (the deterministic frontier) with the firm-specific random error term.

1.28. Although the assumption that the frontier is stochastic is in some circles considered an improvement over deterministic frontier estimators, there are a number of problems with stochastic frontier analysis. These problems derive from the increased demands that this approach places upon the data in conjunction with need to make specific distributional assumptions on the residuals in order to separate inefficiency from measurement errors. In addition, the benchmarking of DNO costs conducted by Ofgem is a two-way process, with a well defined sequence of reports and consultations. In this respect, it is worth noting that the explicit use of a relatively advanced benchmarking methodology, such as SFA, would place considerable demands on both the regulator and the DNOs.

1.29. In addition, SFA is predicated upon the existence of skewed residuals (in the OLS model, for example) which derives from the sum of a random two-sided error component and a one-sided inefficiency component. Another way of thinking about this is that the average inefficiency present in the distribution of residuals is reflected in the asymmetry of the distribution. As such, this model-based decomposition is susceptible to distortionary effects from outliers, especially in small samples. For example, in the estimation of a cost frontier, a number of positive residuals may result in the confounding of outlier effects and firm-specific inefficiency.

1.30. **Remark 3 -** *Preliminary analysis has been conducted using SFA*[13] *based upon the top-down data for the period 2005/06-2008/09. Although the residuals exhibit positive skewness and convergence obtained, the parameter representing the variance of the inefficiency component was not significantly different from zero. As a result, and also based on some of the limitations of this approach (especially in small*

13 The chosen specification for the stochastic frontier model is based on the assumption that the one-sided inefficiency component is distributed half-normal. The reason for this choice is that for this particular stochastic frontier model the asymptotic properties of the efficiency estimates are well established. See Battese and Coelli (1988).

samples), Ofgem do not propose to base the DPCR5 benchmarks for operational activities using SFA.

Section 2.6 - Choice of the benchmark

1.31. At the outset we note that the choice of benchmark and the choice of econometric estimator are obviously linked. For example, a regulator that utilises an estimator based upon a frontier approach, such as Stochastic Frontier Analysis (SFA) or corrected OLS, has the option to benchmark against a frontier. Alternately, the use of the OLS estimator, reflects a sample average efficiency benchmark, given that this estimator does not account for the fact that the distribution of firm-level efficiency is one-sided. However, there need not be a one-to-one relationship between the choice of econometric estimator and the choice of benchmark. Although in principle the use of frontier methods facilitates the identification of the benchmark firm, in many cases adjustments are introduced, in order to circumvent the use of unsustainable minimum cost targets.[14]

1.32. Given the small number of comparators and the attendant difficulties of separating efficiency from other error components using model-based approaches, in DPCR5 data limitations have precluded the use of more sophisticated estimators, such as SFA. As an alternative to SFA it is possible to utilise OLS but in combination with regulator based adjustments. One may think of the COLS estimator as one type of adjustment in which the estimated OLS cost line is shifted down until one point is on the line and all others above it. The obvious disadvantage of this approach is that the frontier is determined by a single firm, and as a result efficiency comparisons are more sensitive to data irregularities. Moreover, this particular type of adjustment attributes all deviations from the frontier as inefficiency. To avoid this problem alternate adjustments may be applied such as moving the OLS down to the upper quartile.[15]

1.33. In adopting such an approach it is important to note that this form of regulator-based decomposition of the composite error term and the subsequent location of an efficiency benchmark, is determined by a combination of an econometric model based on an OLS estimator and regulator knowledge. In addition, in setting the efficiency benchmark at a distance from the deterministic frontier (i.e. regulator knowledge for a model-based approach to allocate a portion of this distance to a random noise component. The adjusted frontier may still be thought of as the minimum cost attainable by the firm: the deterministic component is identified by the OLS estimator, and the random component by the regulator.

14 See Newton Lowry and Getachew (2009) for a useful discussion. In conducting internal efficiency bench-marking for Postcomm LECG (2006) utilise SFA but do not benchmark against the frontier delivery or mail centre.

15 A variant of COLS was adopted by Ofgem in 1999. The estimated intercept adjusted so that the line of predicted costs passed through the second most efficient firm.

1.34. **Remark 4 -** *In accounting for a number of data issues, Ofgem is benchmarking at the upper quartile efficiency rather than the frontier DNO. However, for network operating costs where there is greater variability both in terms of the data and the results, Ofgem are bringing companies that are less efficient to the average; companies that are outperforming the upper quartile receive the upper quartile. This effectively creates a deadband for those in between.*

Section 2.7 - Robustness

1.35. In concluding the discussion of the approach to comparative benchmarking undertaken by Ofgem for DPCR5, we make a number of observations regarding the decisions that Ofgem has made to ensure that the results are robust. First, following feedback received from DNOs after the publication of the May document, Ofgem consulted widely on the use of more than one cost driver, in order to mitigate the effects of omitted factors. Ofgem has since combined engineering knowledge with statistical analysis and in a number of cases estimated regressions which include a second cost driver. Where the regulator has imposed a set of weights, sensitivity analysis has also been conducted.

1.36. Again, following feedback received from DNOs, benchmarking has also been conducted utilising alternative cost drivers, such as the composite scale variable as used in DPCR4. In addition the impact of considering an alternative cost base has been explored. For example, a number of regressions have been estimated where a measure of capital costs such as Non-Load Capex has been added to the measure of operating costs used in the core regressions. Also given that in the core analysis, Group 3 has been analyzed on a per DNO Group basis, an alternative regression was estimated based on analysing Group 3 on a per DNO basis.

1.37. Throughout the process of benchmarking Ofgem has combined statistical analysis with institutional knowledge and dialogue with the DNOs. One critical decision in terms of robustness is that Ofgem has not benchmarked against a frontier, but instead has utilised a combination of benchmarking at the upper quartile, and a more generous approach (as outlined above) when both data variability and results questioned the use of the upper quartile. Ofgem has also continued to use DEA as a cross-check.

Section 3 - Issues with Benchmark 1 - Costs and Cost comparisons

1.38. Prior to undertaking an analysis to determine the comparative efficiency of individual DNOs, a number of decisions have to be made with regards to how DNO costs are calculated, compared and adjusted. Ofgem is aware of the need for cost adjustments. The need for such adjustments provides the primary motivation for the use of regression-based approach to comparative benchmarking, and the reason for not utilising simple unit costs. Regression-based adjustments are considered in section 4. However, prior to the consideration of the appropriate econometric methodology, a number of issues need to be considered such as which costs should be benchmarked, whether to benchmark operating costs or some measure of total costs, how to adjust DNO costs so that they are directly comparable, and the role of top-down and bottom-up benchmarking.

1.39. To frame the discussion, we first state Ofgem's view of what constitutes an appropriate measure of costs and then proceed to examine related issues such as operating costs (opex) versus total costs benchmarking, and boundary problems.

Section 3.1 - An appropriate measure of costs

1.40. Ofgem has formed the view that an appropriate set of costs to include in the benchmarking exercise are those which:

- DNOs have influence over the costs;
- the activity needs to be undertaken by most of the DNOs, rather than being geographically specific (e.g. submarine cable, island generation);
- are relatively stable, rather than one-off or lumpy (e.g. replacement of a fleet of vehicles);
- provide appropriate coverage of the operational activities; and
- boundary issues with the costs need to be understood.

1.41. Although these factors have proved a useful tool in informing Ofgem's modelling approach, it is important to highlight at the outset that there are a number of problems with the use of a simple checklist. First, these items are not necessarily mutually consistent. For example, extending the definition of costs from opex to some measure of total costs might be an improvement in terms of bullet point 4. but may, dependent upon the particular measure of capital costs used, violate bullet point 3.

1.42. In such instances it will be necessary to apply regulator judgement and thereby adopt a pragmatic approach in terms of what costs should be included or excluded. It is also worth emphasising that in some cases there is uncertainty as to whether a specific component should be included and in such cases this uncertainty has been recognised and robustness checks carried out.

Section 3.2 Benchmarking total costs

1.43. Ofgem's core analysis focuses on network operating costs and indirect costs. A number of DNOs have raised concerns that this ignores the impact of trade-offs between operating costs and capital costs. As a result the use of variation in operating costs to estimate DNO-specific efficiency, whilst ignoring variation in capital costs, may introduce errors into efficiency estimates and rankings. In such a case a firm may appear efficient if low operating costs coexist with a high and inefficient capital expenditure.

1.44. One of the key practical issues is the question as to the correct measure of total costs.[16] One might reasonably consider total costs to a firm as comprising operating costs plus capital costs, where capital costs represent the cost of the services to the capital stock. Other measures of total costs have been proposed. For example, benchmarking total costs based on combining operating costs with capex, treats investments as a cash cost, and in doing so raises the possibility of adding further distortions. The reason for this is that such an approach ignores the natural lumpiness of capital expenditures, and therefore can be distortionary unless the timing of such expenditures are the same across firms

1.45. **Remark 5 -** *Ofgem is interested in benchmarking total costs to the extent that it provides a better estimate of their operational efficiency by capturing trade-offs with other areas of costs. In response to issues raised by the DNOs, Ofgem has now extended the scope of its analysis. Ofgem has adopted the approach of adding 10 year average capex to operating costs, thereby considering more generally opex/capex tradeoffs.*

Section 3.3 - Bottom-up versus top-down

1.46. In DPCR5 both bottom-up and top-down benchmarking has been used. The bottom-up analysis has been utilised to inform Ofgem about the efficiencies that can be identified at the level of the activity. Top-down benchmarking (both grouping all indirect costs and grouping all indirect and operating costs) has also been undertaken to take account for potential trade-offs between the respective components of operating costs (or total costs) and any accounting differences between DNOs in the way in which they record these costs.

Boundary Issues

1.47. The use of bottom-up benchmarking is predicated on the allocation of total costs to a set of cost categories. Ofgem is aware of the potential distortionary effects of, for example, a certain group of costs which are benchmarked potentially competing with other, excluded costs. These decisions have obviously been faced by other regulators. For example, ORR benchmarked total Maintenance (M) and Renewal (R) costs together, noting that the trade-offs between M and R and any accounting differences between countries in the way in which they record these costs, are then taken into account.[17]

16 Differences across firms in the way in which expenditures are classified as either capital expenditure (capex) or opex is also a consideration. However, the standardisation of reporting conventions can help reduce this problem.

17 ORR also model maintenance and renewals costs separately as a crosscheck.

Section 3.4 International comparisons

1.48. In order to improve the breadth of the efficiency analysis as well as the sophistication of the measurement technique Ofgem have carried out some initial analysis of international bench-marking. The Office of Rail Regulation took this approach in their recent determination for Network Rail. At this juncture Ofgem have focused on gathering data about DNOs in the North East of the United States (US). The reasons for this focus are that data are relatively easily available from the US regulators' websites and the climate of the North East provides the best match to that of the UK.

1.49. Given the issues of data comparability and adjusting for differences in operating environment and regulatory regime, this has not been taken forwards in DPCR5.

Section 3.5 Cost-Quality Benchmarking

1.50. A number of studies, see for example Yu, Jamasb, and Pollitt (2009), have integrated quality considerations into cost benchmarking. Ofgem have not taken this approach in DPCR5 since this would result in double counting the effect of the quality of service (QoS) incentives elsewhere in the price control. These incentives already price quality based upon consumers' willingness to pay so that any quality differences between DNOs are captured through this incentive rather than the benchmarking. If measures of quality were included in the benchmarking then a high quality DNO could get paid twice for the improvements -once through the benchmarks and again through the QoS incentive.

Section 4 - Issue with Benchmarking 2 - Methodology

1.51. In Section 3 we provided a brief overview of benchmarking issues that relate to the nature of benchmarked costs and the comparison of costs. In this section we provide some discussion on a number of alternate approaches to efficiency estimation in the context of panel data models.

1.52. It is instructive to characterise alternate approaches to efficiency estimation according to the following criteria:

- whether the approach is based upon a deterministic or a stochastic efficiency frontier;
- whether effects are considered random or fixed; and
- the interpretation of firm-specific effects using a panel data estimators.

Section 4.1 The efficiency frontier

1.53. There are two broad approaches to the identification of an efficiency frontier. Traditional panel data estimators such as fixed effects (FE), and corrected ordinary least squares (COLS), are characterised by a set of minimal distributional assumptions and a maintained assumption of a deterministic frontier. In deterministic frontier models, any deviation from a frontier is attributed to inefficiency. If the frontier is constructed based on a cost (production) function, then deviations will be positive (negative) as a result of higher costs (less output) than predicted by the frontier.

1.54. In contrast, models which presume a stochastic frontier are generally estimated using maximum likelihood, in conjunction with a specific set of distributional assumptions that affords the possibility of separating an efficiency component from random noise. Although stochastic frontier might at first glance represent a preferred approach, the use of such an approach comes with additional requirements in terms of the nature of the data, and an understanding of the potential impact of distributional assumptions.

1.55. A stochastic frontier allows for a composite error term. The inefficiency component is, by construction, represented by a one-sided distribution (i.e. one or more firms on the frontier, and others less efficient). The other component, allowing for random effects, is represented by a two-sided distribution, such as a normal. In theory the sum of a two-sided distribution and a distribution with positive skew (e.g. a half-normal), will generate a distribution with skewness (i.e. lack of symmetry). Assuming an underlying cost function, if the residuals have a positive skew, then this indicates that the distribution may reflect the combined effect of measurement error and inefficiency. If the residuals have the wrong skew i.e. are negatively skewed, then this finding calls into question either the specification of the functional form or the distribution of inefficiency itself.

1.56. Therefore, the question of whether a stochastic frontier model is preferred to OLS in this particular context, boils down to the theoretical consideration of whether the composite residual is normally distributed, and as important, whether the additional assumptions imposed by SFA are expected to hold for DNOS in Great Britain.

Section 4.2 - Firm effects

1.57. The structure of panel data, in this context multiple time series observations on a set of DNOs, allows one to consider two types of composite effects: time and firm-specific (DNO) effects. Below we examine two ways of utilising these firm-specific effects: as either controls for unobserved characteristic of firms, or as estimates of firm-specific efficiency.

Firm Specific Effects: Efficiency or Controls

1.58. In the literature firm-specific effects (FSE) effects may be interpreted as either controls for firm-specific unobserved effects or firm-specific time invariant inefficiency.

FSE as Inefficiency

1.59. A number of the early applications of panel data models in the context of efficiency analysis, such as Pitt and Lee (1981) and Schmidt and Sickles (1984), developed models whereby these firm-specific effects were interpreted as firm inefficiency.[18] However, the interpretation that FSE capture time-invariant efficiency is problematic for a number of reasons.

1. Although one might posit that certain components of inefficiency may be attributable to time-invariant factors such as managerial ability (see Farsi and Filippini (2004) and Farsi, Filippini, and Greene (2006)), Ofgem has taken the view that inefficiency is unlikely to be constant over time. One response to this criticism has been to combine the time invariant inefficiency term with a time trend such that inefficiency is allowed to vary over time. This parameterisation has been advocated by Battese and Coelli (1992). Although relatively straightforward to implement, this method imposes a number of significant restrictions. Namely the path of technical inefficiency does not change over time and is constant across firms. Cuesta (2000) provides a useful discussion of issues relating to the modelling of time varying technical inefficiency.

2. Unobserved time-invariant firm heterogeneity will be captured by the FSE, such that there is a strong likelihood of confounding these two factors. In other words, the representation of FSE as inefficiency will generate difficulty when attempting to include cost drivers which are time invariant, or in cases where the within-group variation is low.

3. Given that the distribution of firm inefficiency is, by definition, one-sided, there are a number of transformations that are necessary to create estimates of inefficiency using the fixed effects estimator. Estimates of time invariant efficiencies can be obtained by a comparing each firm with the firm with the minimum fixed effects.[19]

1.60. **Remark 6 -** *In earlier exploratory work Ofgem estimated a number of fixed effects models. The FE estimator delivered efficiencies that demonstrated significantly less correlation with a number of other estimators, including DEA, and*

18 Schmidt and Sickles (1984) proposed fixed effects estimation and Pitt and Lee (1981) proposed the use of a maximum likelihood estimator given a distributional assumption for technical efficiency.

19 See Schmidt and Sickles (1984) for an extended discussion. In addition constructing confidence intervals is also non-trivial.

linear and log-linear OLS pooled panel data models (with time dummies). Farsi and Filippini (2004) report similar findings using a sample of 59 distribution utilities in Switzerland. One obvious problem is that the precision of the estimated parameters depends on the extent of within-firm variation. This was relatively low given that (in these runs) we only observed 3 time periods for each DNO.

FSE as Controls

1.61. Since the DNOs operate in different regions, they will face different operating conditions such as topography, and network size and shape. Although it may be possible to measure some of these factors, a number of panel data estimators afford the possibility of controlling for these effects. In this respect, an alternate interpretation is that each firm-specific effect represents a composite of unobserved DNO-specific cost attributes that do not vary over time.

1.62. Although Ofgem believe that the interpretation of FSE as a measure of firm-specific time-invariant cost attributes (i.e. network and location-related factors that are fixed over time) is more reasonable than the above, representing FES as controls can be disregarded as they will also pick up any average inefficiency over the time period which cannot be disentangled from the other components making up the estimate.[20] Subsequently, it is likely that the distance from an efficiency frontier may represent both inefficiency and a combination of the impact of omitted variables and model misspecification.

Remark 7 *Given the small sample size it is not possible to utilise the fixed effects (over DNOs) estimator.[21] In this respect regulator intervention based on the selection of a number of pre-model adjustments is required to facilitate the separation of unobserved firm-specific effects (in section 2.3.1 referred to as normalisation adjustments) from other cost components. In this specific context, the question as to whether to treat the firm specific effects as fixed or random becomes mute.*

Section 4.3 - Time effects

1.63. In the Core regressions Ofgem has used a pooled OLS estimator with time dummies. The time dummies can be used to separate neutral technical change from technical efficiency, and also other factors such as changes in input prices and any other industry-wide shocks such as bad weather.

20 Greene (2005) advocates what he refers to as a true fixed effect models as one solution to this problem. This (stochastic frontier) model utilises the panel structure of the data to estimate fixed effects to control for firm-specific heterogeneity; and employs distributional assumptions to separate a one-sided time varying efficiency component from other time-varying unobserved error components.
21 It is important to note that estimates of panel data fixed effects are consistent for a fixed cross-section dimension (the number of DNOs) and for the number of time periods becoming large.

Section 4.4 - Other regulatory approaches

1.64. It is instructive to briefly compare Ofgem's approach in DPCR5 with the approach adopted by another UK regulator, the Office of Rail Regulation (ORR). The Institute for Transport Studies (University of Leeds) has undertaken efficiency analysis jointly with ORR in benchmarking rail costs internationally and internally within the UK. A core component of this analysis is a stochastic frontier model, that distinguishes between random noise and inefficiency, and allows efficiency to vary over time and in flexible manner; a time varying efficiency parameter is estimated for each firm, so that the direction and extent of efficiency variation over time can be different.

1.65. Notwithstanding the likely differences between the two regulators in terms of a view as to the suitability of such a modelling approach, a critical difference is obviously the fact that this work was undertaken using a total of 143 observations - thirteen infrastructure companies observed over a 11 year period.

Precision of efficiency scores

1.66. One notable drawback with many implementations of efficiency analysis is that the uncertainty attached to the estimated efficiencies is ignored. In this section we discuss the motivation for the use of interval estimates for the efficiency scores, and also a number of regulator approaches to this problem, including the choice of the benchmark and the use of banding the efficiency distribution.

1.67. It is possible to identify a number of motivations for interval benchmarking. One motivation follows from the quality of the data. The provision of interval estimators in conjunction with point estimates is beneficial to companies in the face of data imperfections. At the same time conducting regulation with interval estimates provides the regulator with incentives to increase both the number of observations and the quality of measurable data, thereby reducing unexplained variation and the width of inefficiency intervals. However, the primary motivation follows from the observation that subsequent to a comparative benchmarking exercise, point and rank estimates of DNO-specific efficiency scores are estimated. However, given that both statistics are point estimates the uncertainty is ignored unless some other steps are taken. Possible regulatory adjustments to manage uncertainty are discussed in the next section.

Section 5.1 -Adjustments to efficiency scores

1.68. A regulator may decide to impose a banding of the distribution of firm-level inefficiencies. If for example, firms are allocated to groups (or bands) then firm efficiency is effectively recast as efficiency type i.e. very efficient (the frontier), efficient, middle efficiency, and so on. The regulators task is now less onerous. He simply has to allocate firms to efficiency bands, such that within bands firms are treated as equally efficient.

1.69. The banding of the efficiency distribution may be thought of as a non model-based solution to the question as to how to account for the uncertainty attached to point estimates of efficiency scores. As the number of bands approaches the number of firms, the regulator applies increasingly finer judgements in the setting of efficiency scores. The implicit assumption is then that the data and method used is sufficient to identify price setting at the level of the firm.

1.70. As discussed in section 2.6, Ofgem has adjusted for data and other uncertainties by benchmarking at the upper quartile efficiency rather than the frontier DNO. In addition, in cases such as network operating costs where there is greater variability both in terms of the data and the results, a different approach, similar in spirit to banding, has been used. In this instance companies that are less efficient than the average, receive the average efficiency score. Companies that are outperforming the upper quartile receive the upper quartile, creating a deadband for those in between.

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