Electricity Distribution Price Control Review Methodology and Initial Results Paper

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

Overview:

Ofgem regulates the 14 DNOs, who are all regional monopolies to protect the interests of present and future consumers. We set a price control every five years. This sets the total revenue allowances that each DNO can collect from customers 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 is the third document in the review. We have set out details of our cost assessment methodology and our initial results. We have also presented our proposals for two areas of quality of service and our proposed approach to dealing with tax, regulatory asset value and overall incentives. This is the final consultation before we publish our initial proposals on each company's revenue requirements in late July 2009.

This document contains the appendices for the Methodology and Initial Results Paper

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Context

In December 2008, we published our Policy Paper for the distribution price control review (DPCR5). The document focussed on three key themes, the environment, customers and networks and set out our views on the overall approach to setting the new control, the methodologies we propose to use, the structure of incentives and the new regulatory arrangements that we think are appropriate.

In February 2009 all DNOs submitted updated forecasts for the final two years of DPCR4 and the five years of DPCR5. We held initial discussions with each of them. Forecasts have reduced from their initial level in August 2008, but still show a significant increase in both network investment and operating costs between DPCR4 and DPCR5 as outlined in this document. We have identified significant issues with the forecasts and will seek further information from the DNOs to justify their forecasts.

This document sets out details of our cost assessment methodology and the initial results for a number of core cost areas. We will continue to develop our work in this area as we develop draft allowances for the Initial Proposals document. We have not yet completed out analysis or considered our draft allowances. Readers should not therefore try to draw any inferences about them from any of the figures published in this document.

Since December there has been continued volatility in the economy, which makes it even more difficult than usual to forecast accurately. The need for investment is highly uncertain and two key drivers will be how effective measures to improve energy efficiency are and how long it takes for the economic recovery to begin. Input prices, including those that affect financing costs and operating expenditure, will be highly influenced by global economic conditions, the length of the recession and any periods of general deflation. We will need to carefully consider how best to manage this risk and uncertainty so that DNOs do not make windfall gains at customers' expense from economic circumstances, but have sufficient resources over the five years to meet their needs over a wide range of possible outcomes. We have set out a chapter on our evolving thinking on how best to deal with this uncertainty.

We have continued to hold a number of industry working groups focussed on the three key DPCR5 themes and financial issues, which have informed the development of our policy proposals. We continue to make use of these groups to develop our thinking on financial issues, outputs and other policy matters not included in this document, such as improving connections service, basing DNO rewards on a broader measure of customer satisfaction and encouraging DNOs to reduce losses and innovate to tackle climate change. We will set out our proposals for these areas in Initial Proposals in July.

Associated Documents

- 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)
- Regulating energy networks for the future: RPI-X@20 Principles, Process and Issues (13/09)

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Appendix 5 – Cost assessment methodology – Further details

Introduction

1.1. Chapter 3 set out our overall approach for the assessment of operational costs together with our initial results. This appendix provides additional details of the methodology and analysis undertaken and of the results of the comparative benchmarking and other work undertaken in relation to Operational Activities.

1.2. The basis for our cost analysis is the cost reporting data provided annually by each DNO in the regulatory reporting packs (RRP) and the data provided in the forecast business plan questionnaire (FBPQ) in February 2009. The timing of the FBPQ has allowed the DNOs the opportunity to amend any known errors in the RRP data, however, we have found that for all of the DNOs minor errors have been found in the FBPQs that have meant a direct reconciliation of all the data sources has not been possible. All of the DNOs have given assurances that these errors will be corrected in the June submissions.

Cost Assessment Methodology

Comparative efficiency techniques

1.3. We have relied on two techniques for assessing the relative efficiency of the DNOs in their operating activities:

- time-series panel data regression analysis, and
- data envelopment analysis (DEA).

1.4. This section provides more details on these techniques.

Time-series panel data regressions

1.5. At DPCR4 Ofgem carried out its benchmarking using data from a single year. It was not possible to use more than one year's data as it had not been collected on a consistent basis over time.

1.6. Since DPCR4 we have developed the RRP system of reporting which collects DNO data annually on a consistent basis. This additional data makes it possible to conduct our comparative analysis with techniques that make use of this additional data. Time series panel data regressions make use of this additional data and can provide better estimates of the impact of cost drivers on costs than is possible with only a single year's data. Better estimates of the impacts of cost drivers can be expected to provide better insights into the relative efficiency of the DNOs. This benefit of time series panel data regressions over cross-sectional regressions relies on the assumption that the cost drivers have a constant effect over time e.g. for all years in the sample: a 1 per cent increase in the cost driver coincides with an X per cent increase in costs.

1.7. Our models have used data from three years. Over this time period there will be differences between years that the models must account for. There will be year specific effects that will make average costs different between years. Changes in these time specific effects will reflect changes in a number of factors including:

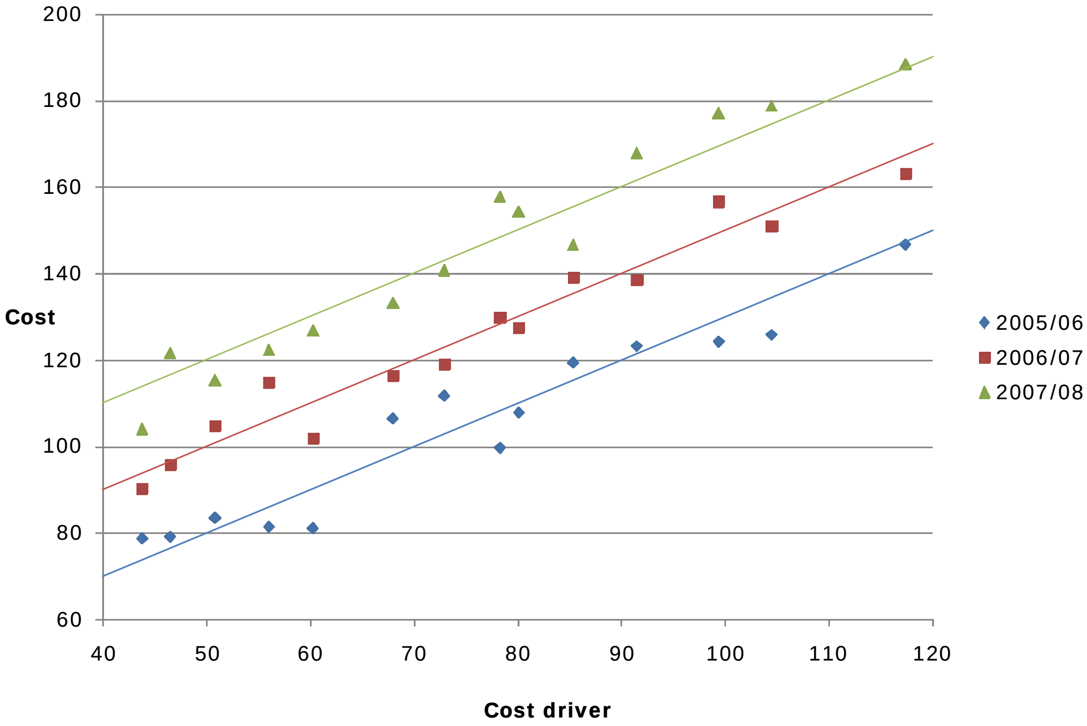
- Input prices: an increase in input prices will increase the average cost of an activity.
- Industry-wide efficiency: over time the industry will make efficiency improvements that all else being equal will reduce the cost of conducting the various activities.
- Industry-wide shocks: there may be events in a year that change activity levels across the industry. For example, if there was particularly bad weather in a year one would expect costs in that year to be higher as a result.

1.8. To accommodate these time specific effects we have adopted a time fixed effects approach. This means that each year has its own parameter which helps determine the average cost of the activity in that year.

1.9. When these models are estimated, one can calculate the expected/average cost of performing an activity in a given year. Where companies' actual costs lie relative to this average level provides an indication of their efficiency relative to this average.

1.10. This is illustrated in figure 1 below.

Figure 1 - Illustration of a time series panel data model



1.11. The following can be seen from this illustration:

- The cost driver has the same effect in all years. In this example an extra unit of the cost driver coincides with an extra unit of costs.
- There are year specific effects that lead to different average costs in each year. In this example average costs have increased from year to year.
- An indication of the relative efficiency of a DNO can be obtained by comparing the actual costs with the average costs in that year for a given cost driver. For example, companies that lie above the fitted line have higher than average costs for that level of cost driver and this indicates that we might expect them to be less efficient than average.

1.12. It is important to note that differences between actual costs and the average costs expected by the model do not solely reflect differences in efficiency from the industry average. There may be a number of factors that might be reflected in this difference including the following:

- Measurement errors and differences in cost allocation methodologies in the data.

- Costs that can be explained by another cost driver that has been omitted from the model.
- Shocks/factors that have only affected a subset of the industry. For example, there might be planning restrictions that only have an impact in a limited number of regions.

1.13. We have tried to mitigate these factors by providing guidance on how RRP data should be reported, and trying to choose the most appropriate cost driver given the data available.

1.14. In addition we have carried out a number of DNO-specific adjustments prior to the modelling to account for any unique operating circumstances. These adjustments have been made for factors such as regional labour costs, regional contractor costs, and the integrated delivery team (IDT) as set up by EDFE.

1.15. Despite these efforts differences between companies from the modelling will not just reflect differences in efficiency. We would expect some averaging of these other factors so that a DNO with costs greater than those predicted by our model would be less efficient than average but not by the full difference.

Application of regression analysis

1.16. During the DPCR4 period leading up to DPCR5 we have regressed DNO costs at an individual activity level (as reported in table 2.2 of the RRP and table T3 of the FBPQ). Analysis at this level has provided valuable feedback to help with the task of cleansing the data to identify reporting differences between the DNOs. There remain concerns that the quality of the data collection and reporting systems of the DNOs are not adequate to data reporting by some of the DNOs.

1.17. Our view is that, while regressing costs at a highly disaggregated level is valuable for data cleansing it is not appropriate to use such highly disaggregated analysis for the process of allowance setting because of the different cost structures among DNOs and the potential for different cost allocations.

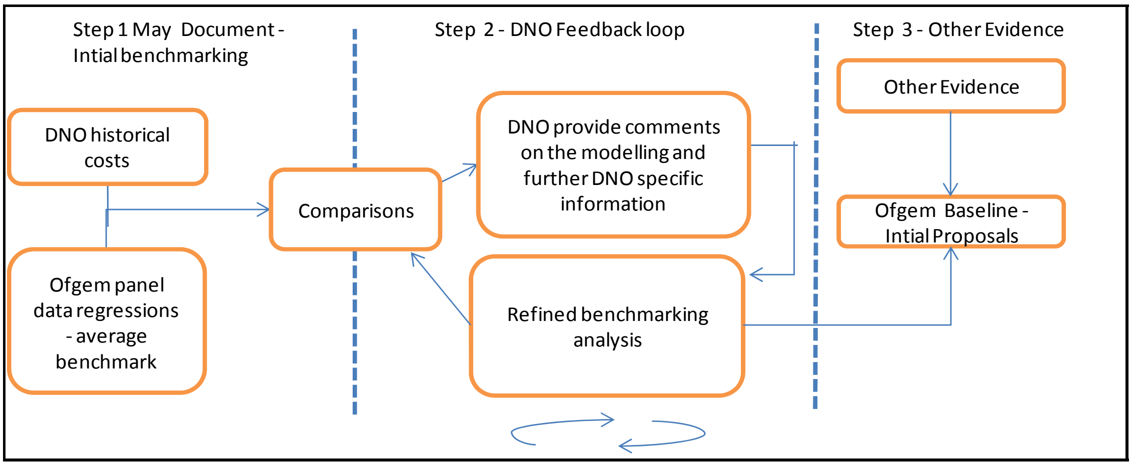
1.18. The structure of the industry is such that there is only one singleton DNO. All other DNOs are part of a group structure with two or three DNOs in them. There are undoubtedly potential cost savings for DNOs run together as part of a group. To identify where those savings can be realised we are of the view that additional benefit can come from comparative efficiency analysis on a group basis to complement analysis on an individual DNO basis.

1.19. In summary, we have undertaken, and will continue to develop, our comparative efficiency analysis using time-series panel data regression analysis as the core of our analysis applied to the following combinations of costs:

- **Groups**: by combining indirect activities where we can identify common cost drivers,
- **Single Group**: by combining indirect activities using a single composite, cost driver,
- **Top Down**: by combining indirect activities with network operating costs under a single composite cost driver,
- **Per DNO**: we will run each of the above groupings of costs in the regressions on an individual DNO basis, and
- **Per DNO Group**: we will also run each of the groupings on a DNO group basis

1.20. Figure 2 provides an overview of our approach to the cost assessment work showing how the results of our analysis presented in this document fit into the overall process of determining baselines for Initial Proposals. The key to this approach is that the regression results do not represent our baselines but provide a valuable input into the process for determining those baselines together with additional information and data provided by the DNOs and others.

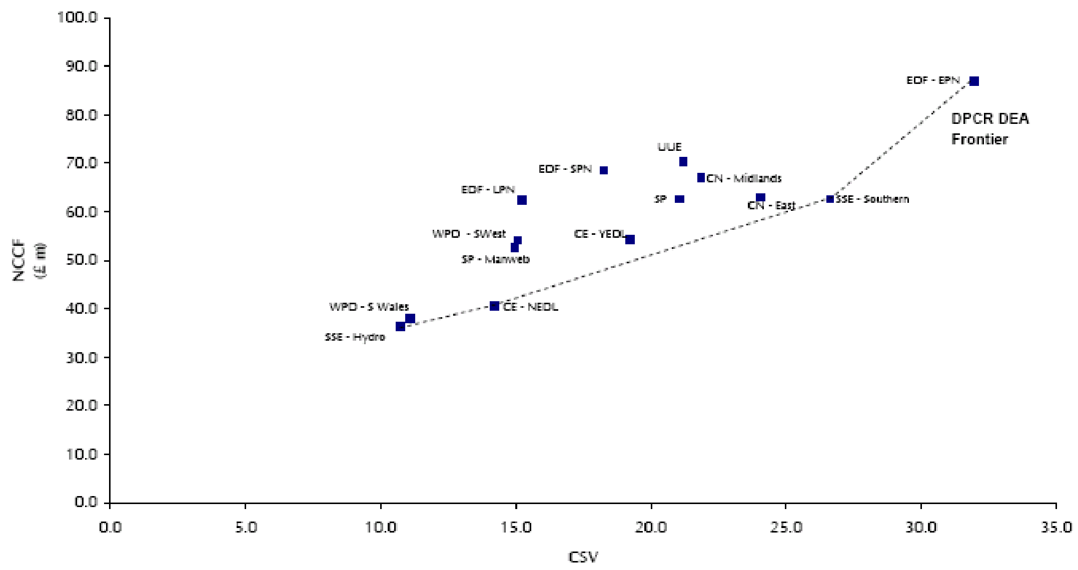
Figure 2 - Representation of the cost assessment process for setting baselines



Data envelopment analysis (DEA)

1.21. DEA is a non-statistical approach that can be used for comparative efficiency analysis. A frontier is "wrapped" around the data such that the most efficient companies lie on the frontier, while the less efficient companies lie above the frontier. A DEA frontier is illustrated in figure 3 below which was used at DPCR4 in the September 2004 update paper.

Figure 3 - Illustration of a frontier estimated by DEA



1.22. This demonstrates how the frontier is fitted around the observed data such that all companies either lie on the frontier or above it. The further a company lies above the frontier the more inefficient it is deemed to be.

1.23. At present we plan to place more weight on the results of our regression analysis than those from DEA for the following reasons:

- The frontier estimated by DEA is very sensitive to a small number of observations. The frontier plotted in the figure above is determined by only four DNOs, the other ten do not affect the frontier in any way. In some cases the frontier could be determined by only two DNOs. In a regression, all of the observations affect the estimated parameters so the results cannot be influenced so heavily by a single DNO.

- The way that DEA works will always mean that some DNOs will always lie on the frontier. In the example above, the shape of the frontier will mean: the DNO with the largest cost driver (CSV) will always lie on the frontier regardless of its expenditure, and the DNO with the lowest expenditure will always lie on the frontier regardless of the size of its cost driver. This is not the case with regression analysis.

- DEA does not have any tests that can be used to help select the general functional form or the cost drivers to include in the analysis. Regression analysis has a battery of diagnostic tests that can be used to assist in selecting the most appropriate variables and functional forms.

- DEA assumes no measurement error or noise in the data and that all the relevant cost drivers have been specified. Regression analysis can accommodate such factors within the residual of the regression which captures all of these "unexplained" costs.

1.24. Despite these issues the two approaches have given us very similar efficiency ranking results to date which increases confidence in the robustness of our analysis. We will therefore use the DEA results as a cross-check on our time series panel data modelling.

1.25. We have undertaken DEA analysis of the costs used in the comparative benchmarking on a top-down basis using a Variable Returns to Scale (VRS) functional form. The results provided by this approach assign a score up to one (frontier). Because the output is on a different basis to the scores provided by the ordinary least squares (OLS) regressions we have presented a comparison of the ranking of the DNOs under those regressions and by DEA in table 1.

Table 1 - Comparison of DNO rankings under linear and log-log core regressions to the output of DEA analysis

DNO	Ranking: Linear Top-Down Per DNO	Ranking: Log-Log Top-Down Per DNO	DEA VRS (2007-08)
CN West	14	14	14
CN East	8	6	6
ENW	10	9	10
CE NEDL	5	5	5
CE YEDL	9	11	11
WPD S Wales	2	3	3
WPD S West	4	4	4
EDFE LPN	12	12	12
EDFE SPN	7	10	9
EDFE EPN	11	8	8
SP Distribution	13	13	13
SP Manweb	6	7	7
SSE Hydro	1	2	1
SSE Southern	3	1	1

1.26. Table 1 shows a consistency of results between the OLS core regressions and the results of the DEA analysis

Results

1.27. Chapter 3 presents the core results on an individual DNO basis and provides summary comments on the alternative regressions. This section of the appendix provides the core results on a DNO Group basis and compares the results of these two approaches and includes more details of the results of the alternative regressions.

Core Results

1.28. Table 2 presents the results of our core analysis on a DNO Group basis. Table 3 provides a comparison of these results with the results in Chapter 3 of the main document which were carried out on an individual DNO basis.

1.29. In order to infer an efficiency score for each DNO from the per DNO Group regressions we have allocated the output of the models to individual DNOs based on the relevant cost drivers.

Table 2 - Results of the benchmarking for our base scenario on an individual DNO Group basis

	Linear			LogLog			
DNOs	Top Down	Single Group	Groups	Top Down	Single Group	Groups	Average Score
CN West	123%	124%	123%	124%	128%	128%	125%
CN East	97%	103%	99%	98%	101%	101%	100%
ENW	101%	94%	93%	97%	90%	90%	94%
CE NEDL	103%	92%	100%	101%	99%	99%	99%
CE YEDL	103%	106%	101%	102%	99%	99%	102%
WPD S Wales	98%	74%	85%	95%	87%	87%	88%
WPD S West	95%	85%	82%	92%	85%	85%	88%
EDFE LPN	121%	107%	120%	125%	117%	115%	117%
EDFE SPN	105%	104%	108%	109%	117%	117%	110%
EDFE EPN	96%	116%	103%	99%	106%	106%	104%
SP Distribution	120%	116%	120%	119%	119%	119%	119%
SP Manweb	101%	102%	96%	100%	99%	99%	99%
SSE Hydro	87%	65%	94%	87%	89%	90%	85%
SSE Southern	72%	89%	82%	72%	75%	76%	78%

1.30. The regression on a DNO Group basis only includes 21 points in the time series data rather than the 42 data points on an individual DNO basis. The results are likely to be less statistically robust as a result.

1.31. Because of the size of the EDFE group compared to any other group structure those data points are likely to have a large influence on the location of the regression line and we will take this into account when considering the results of the analysis.

Table 3 - Comparison of average scores on a per DNO basis to those on a per DNO Group basis

DNOs	Average Score			Average Ranking		
	Per DNO	Per DNO Group	Difference	Per DNO	Per DNO Group	Difference
CN West	124%	125%	1%	14	14	0
CN East	102%	100%	-2%	8	8	0
ENW	103%	94%	-9%	9	5	-4
CE NEDL	95%	99%	4%	5	6	1
CE YEDL	104%	102%	-2%	10	9	-1
WPD S Wales	81%	88%	7%	2	4	2
WPD S West	89%	88%	-2%	4	3	-1
EDFE LPN	104%	117%	13%	11	12	1
EDFE SPN	102%	110%	8%	7	11	4
EDFE EPN	108%	104%	-4%	12	10	-2
SP Distribution	116%	119%	3%	13	13	0
SP Manweb	101%	99%	-2%	6	7	1
SSE Hydro	71%	85%	14%	1	2	1
SSE Southern	84%	78%	-6%	3	1	-2

1.32. The analysis on a DNO Group basis gives some notably different results for some of the DNO groups but not for others. As expected the results for DNOs within groups are closer together and this is particularly notable for CE, WPD and SSE, however, for some groups the results seem more diverse and this is the case for CN, EDFE and SP.

1.33. The ranking of the results remain very similar across both methods except for ENW where, unsurprisingly as the only singleton, the results are improved on a DNO Group basis, and for EDFE SPN where the ranking moves them closer to the other EDFE group DNOs.

Alternative Drivers

1.34. The following paragraphs provide more details of the results of the analysis under the different scenarios we identified in chapter 3 and compares those to the core benchmarking results.

Group 1 Alternative Drivers

1.35. We have tested our results for Group 1 costs using the alternative drivers of modern equivalent asset value (MEAV) and unit volume cost drivers. The unit volume cost driver is derived by multiplying the assets added to their network by each DNO multiplied by the average of the unit costs for each asset submitted by the DNOs in the FBPQs.

1.36. Tables 4 and 5 compare the results of the Groups regressions using the different drivers with the core results on an individual DNO basis using both linear and log-log regressions.

1.37. The results show that for some DNOs the different drivers can result in different efficiency scores. We will undertake further work over the coming months to consider those differences and consider them in determining our baselines for calculating inputs to the information quality incentive (IQI) mechanism.

Table 4 - Comparison of core results for 'Groups' regressions using MEAV as a driver for the Group 1 costs

DNO	Core Result: Per DNO Linear	Core Result: Per DNO Log-Log	Result: Linear: MEAV as Cost Driver	Result: Log--Log: MEAV as Cost Driver	Difference: Linear	Difference: Log-Log
CN West	123%	124%	124%	126%	1%	1%
CN East	102%	102%	104%	104%	2%	2%
ENW	105%	101%	106%	101%	1%	1%
CE NEDL	93%	96%	92%	97%	-0%	0%
CE YEDL	107%	102%	105%	100%	-1%	-1%
WPD S Wales	75%	83%	74%	82%	-1%	-1%
WPD S West	87%	91%	85%	89%	-2%	-2%
EDFE LPN	100%	100%	103%	103%	3%	4%
EDFE SPN	100%	103%	99%	102%	-0%	-0%
EDFE EPN	112%	108%	112%	108%	0%	-0%
SP Distribution	116%	115%	116%	115%	-0%	-0%
SP Manweb	102%	102%	103%	104%	1%	2%
SSE Hydro	66%	74%	64%	71%	-2%	-2%
SSE Southern	90%	83%	89%	81%	-1%	-1%

1.38. Using MEAV as a cost driver for Group 1 costs results in an improvement in efficiency scores for WPD S West and SSE Hydro of around 2 per cent. Using MEAV also results in a worsening of results for EDFE LPN of around 3 per cent and for CN East and SP Manweb of 2 per cent.

Table 5 - Comparison of core results for 'Groups' regressions using Unit Cost/Volume as a driver for the Group 1 costs

DNO	Core Result: Per DNO Linear	Core Result: Per DNO Log-Log	Result: Linear: Unit Volume Cost Driver	Result: Log-Log: Unit Volume Cost Driver	Difference: Linear	Difference : Log-Log
CN West	123%	124%	123%	125%	-0%	0%
CN East	102%	102%	105%	106%	3%	3%
ENW	105%	101%	107%	103%	3%	3%
CE NEDL	93%	96%	92%	95%	-1%	-1%
CE YEDL	107%	102%	106%	101%	-1%	-1%
WPD S Wales	75%	83%	72%	79%	-3%	-4%
WPD S West	87%	91%	84%	87%	-3%	-3%
EDFE LPN	100%	100%	96%	102%	-4%	2%
EDFE SPN	100%	103%	99%	102%	-0%	-0%
EDFE EPN	112%	108%	118%	111%	6%	3%
SP Distribution	116%	115%	117%	116%	1%	1%
SP Manweb	102%	102%	102%	103%	1%	1%
SSE Hydro	66%	74%	62%	68%	-4%	-5%
SSE Southern	90%	83%	90%	83%	-0%	-0%

1.39. Using the unit volume cost driver for Group 1 costs results in an improvement in efficiency score for the WPD DNOs of around 3 per cent and for SSE Hydro of around 4 per cent. Using unit/costs also results in a worsening of results for EDFE EPN, CN East and ENW of around 3 per cent.

Group 2 Alternative Drivers

1.40. We have tested our results for Group 2 costs using MEAV as an alternative driver. Table 6 compares the results of the Groups regressions using the different driver with the core results on an individual DNO basis using both linear and log-log regressions.

1.41. The results show that for some DNOs, particularly EDFE LPN, the different drivers can result in some notable different efficiency scores. We will undertake further work over the coming months to identify potential reasons for those differences and take them into account in determining our baselines for calculating inputs to the IQI mechanism.

Table 6 - Comparison of core results for 'Groups' regressions using MEAV as a driver for the Group 2 costs

DNO	Core Result: Per DNO Linear	Core Result: Per DNO Log-Log	Result: Linear: MEAV as Cost Driver	Result: Log--Log: MEAV as Cost Driver	Difference: Linear	Difference : Log-Log
CN West	123%	124%	125%	127%	3%	2%
CN East	102%	102%	105%	104%	3%	2%
ENW	105%	101%	104%	100%	-0%	-1%
CE NEDL	93%	96%	93%	98%	0%	2%
CE YEDL	107%	102%	105%	100%	-1%	-1%
WPD S Wales	75%	83%	73%	83%	-2%	-0%
WPD S West	87%	91%	84%	89%	-3%	-2%
EDFE LPN	100%	100%	108%	109%	9%	9%
EDFE SPN	100%	103%	100%	103%	0%	1%
EDFE EPN	112%	108%	112%	106%	0%	-2%
SP Distribution	116%	115%	115%	114%	-2%	-1%
SP Manweb	102%	102%	105%	106%	3%	4%
SSE Hydro	66%	74%	62%	71%	-3%	-3%
SSE Southern	90%	83%	87%	79%	-3%	-4%

1.42. Using MEAV as an alternative driver for Group 2 costs results in an improvement in efficiency scores for the WPD S West of around 2 per cent and for the SSE DNOs of around 3 per cent. Using MEAV also results in a worsening of results particularly for EDFE LPN at around 9 per cent and for the CN DNOs and SP Manweb of around 3 per cent.

Group 3 Alternative Drivers

1.43. We have tested our results for Group 3 costs using the DPCR4 Composite Scale Variable (CSV) as an alternative driver. Table 7 compares the results of the Groups regressions using the different driver with the core results on a per DNO group basis using both linear and log-log regressions.

1.44. The results show that for some DNOs, particularly EDFE LPN, the different drivers can result in noticeably different efficiency scores. We will undertake further work over the coming months to identify potential reasons for those differences and take them into account in determining our baselines for calculating inputs to the IQI mechanism.

Table 7: Comparison of core results for 'Groups' regressions using the DPCR4 CSV as a driver for the Group 3 costs on a DNO Group basis

DNO	Core Result: Per DNO Group: Linear	Core Result: Per DNO Group: Log-Log	Result: Linear: CSV as Cost Driver	Result: Log--Log: CSV as Cost Driver	Difference: Linear	Difference : Log-Log
CN West	123%	128%	123%	128%	-0%	-0%
CN East	99%	101%	99%	101%	0%	0%
ENW	93%	90%	93%	90%	0%	0%
CE NEDL	100%	99%	100%	99%	0%	-0%
CE YEDL	101%	99%	101%	99%	0%	0%
WPD S Wales	85%	87%	85%	87%	-0%	-0%
WPD S West	82%	85%	82%	85%	0%	0%
EDFE LPN	120%	115%	112%	114%	-7%	-1%
EDFE SPN	108%	117%	108%	117%	0%	0%
EDFE EPN	103%	106%	106%	106%	3%	-0%
SP Distribution	120%	119%	120%	119%	-0%	-0%
SP Manweb	96%	99%	96%	99%	0%	0%
SSE Hydro	94%	90%	94%	90%	0%	0%
SSE Southern	82%	76%	82%	76%	0%	0%

1.45. Using the DPCR4 CSV as an alternative driver for Group 4 costs results in a notable improvement in efficiency scores for the EDFE LPN of 7 per cent on a linear basis and a worsening of results for EDFE EPN of 3 per cent for linear regressions. The results on a log-log basis do not change notably for any DNOs.

Results - Top-Down regression with DPCR4 CSV cost driver

1.46. We have run alternative analysis of the costs at a top-down level using a composite scale variable calculated in accordance with the methodology used at DPCR4. This DPCR4 CSV used the three metrics of Network Length, Units Distributed and Customer Numbers.

1.47. The DPCR4 CSV has been criticised because it does not relate directly to the factors that impact on the costs incurred by the DNOs. Some DNOs have continued to use the DPCR4 CSV in their own analysis because they view it as a reasonable proxy for the relative network scale of the DNOs.

1.48. We have analysed DNO costs for the years 2005-06 to 2007-08 using the methodology used at DPCR4, however, we have excluded costs from the comparative benchmarking (e.g. IT & Telecoms, Property Management, Wayleaves), and included some other costs (e.g. underground cable non-load capex), for the DPCR5 review that were not excluded as part of the DPCR4 review.

1.49. We have provide in table 8 a comparison of the top-down regression results using the composite driver used in the core analysis against the CSV calculated on the same basis as at DPCR4. The table also includes a comparison of the relative rankings of the DNOs.

Table 8 - Comparison of core top-down regression on a per DNO basis using DPCR4 CSV as a cost driver

DNO	Core Result	Result: DPCR4 CSV as driver	Difference	Core Ranking	Ranking: DPCR4 CSV as driver	Difference
CN West	125%	116%	-9%	14	13	-1
CN East	103%	99%	-4%	8	7	-1
ENW	105%	110%	5%	10	12	2
CE NEDL	94%	100%	5%	5	8	3
CE YEDL	105%	108%	3%	9	11	2
WPD S Wales	80%	81%	1%	2	2	0
WPD S West	89%	90%	1%	4	3	-1
EDFE LPN	110%	98%	-12%	12	6	-6
EDFE SPN	102%	95%	-7%	7	5	-2
EDFE EPN	107%	100%	-6%	11	9	-2
SP Distribution	118%	107%	-10%	13	10	-3
SP Manweb	100%	118%	18%	6	14	8
SSE Hydro	68%	69%	1%	1	1	0
SSE Southern	81%	91%	11%	3	4	1

1.50. Using the CSV as a driver for the top-down linear regression results in markedly improved results for the EDFE and CN DNOs and for SP Distribution. It also results in markedly worse results for particularly SP Manweb and SSE Southern. Using the CSV does reduce the range of scores from 68 per cent to 125 per cent to 69 per cent to 116 per cent being mostly due to the improved performance of CN West. Using the two drivers does not alter the DNOs that appear to be the best performing in the comparative benchmarking, i.e. the SSE and WPD DNOs.

1.51. The difference in rankings between using our core top-down driver and the DPCR4 CSV is most notable for SP Manweb, falling 8 places, and EDFE LPN, improving by six places.

1.52. We do not favour the use of the CSV as a proxy for network scale and we are concerned that the apparent improved 'fit' in our current results using the DPCR4 CSV as a driver may be related to its use by Ofgem as a driver over a number of price controls.

Summary of Results

1.53. Table 9 provides a summary of the results of the core analysis and the options discussed above.

Table 9 - Summary analysis results

	Core Results												Alternative Adjustments			Group 3 on a per DNO Group basis		Alternative Drivers Group 1				Alternative Drivers Gp 2		Alternative Drivers Gp 3		DR4 Driver
													Normalised Pensions	Labour/ Contractor Adjustment for all	No IDT Adjustment			MEAV	MEAV	Unit/ Volume	Unit/ Volume	MEAV	MEAV	DPCR4 CSV	DPCR4 CSV	DPCR4 CSV
	Per DNO						Per DNO Group						Per DNO	Per DNO	Per DNO	Combined	Combined	Per DNO	Per DNO	Per DNO	Per DNO	Per DNO	Per DNO	Per DNO	Per DNO	Per DNO
	Linear			Log-Log			Linear			Log-Log			Linear	Linear	Linear	Linear	Log-Log	Linear	Log-Log	Linear	Log-Log	Linear	Log-Log	Linear	Log-Log	Linear
	Top Down	Single Group	Groups	Top Down	Single Group	Groups	Top Down	Single Group	Groups	Top Down	Single Group	Groups	Top Down	Top Down	Top Down	Groups	Groups	Groups	Groups	Groups	Groups	Groups	Groups	Groups	Groups	Top Down
CN West	125%	123%	123%	123%	125%	124%	123%	124%	123%	124%	128%	128%	128%	127%	123%	121%	125%	124%	126%	123%	125%	125%	127%	123%	124%	116%
CN East	103%	102%	102%	99%	103%	102%	97%	103%	99%	98%	101%	101%	105%	106%	101%	104%	103%	104%	104%	105%	106%	105%	104%	102%	103%	99%
ENW	105%	105%	105%	103%	100%	101%	101%	94%	93%	97%	90%	90%	102%	106%	104%	100%	96%	106%	101%	107%	103%	104%	100%	105%	101%	110%
CE NEDL	94%	93%	93%	98%	97%	96%	103%	92%	100%	101%	99%	99%	93%	94%	93%	93%	96%	92%	97%	92%	95%	93%	98%	93%	96%	100%
CE YEDL	105%	106%	107%	103%	101%	102%	103%	106%	101%	102%	99%	99%	103%	106%	103%	106%	101%	105%	100%	106%	101%	105%	100%	107%	102%	108%
WPD S Wales	80%	75%	75%	90%	84%	83%	98%	74%	85%	95%	87%	87%	82%	82%	79%	75%	83%	74%	82%	72%	79%	73%	83%	75%	83%	81%
WPD S West	89%	86%	87%	92%	91%	91%	95%	85%	82%	92%	85%	85%	90%	90%	88%	87%	90%	85%	89%	84%	87%	84%	89%	87%	91%	90%
EDFE LPN	110%	101%	100%	115%	101%	100%	121%	107%	120%	125%	117%	115%	109%	109%	115%	101%	102%	103%	103%	96%	102%	108%	109%	99%	99%	98%
EDFE SPN	102%	100%	100%	103%	103%	103%	105%	104%	108%	109%	117%	117%	101%	100%	104%	101%	105%	99%	102%	99%	102%	100%	103%	99%	102%	95%
EDFE EPN	107%	112%	112%	101%	108%	108%	96%	116%	103%	99%	106%	106%	105%	106%	112%	113%	110%	112%	108%	118%	111%	112%	106%	111%	108%	100%
SP Distribution	118%	116%	116%	118%	115%	115%	120%	116%	120%	119%	119%	119%	117%	114%	116%	116%	115%	116%	115%	117%	116%	115%	114%	116%	115%	107%
SP Manweb	100%	102%	102%	100%	103%	102%	101%	102%	96%	100%	99%	99%	100%	99%	99%	101%	102%	103%	104%	102%	103%	105%	106%	102%	102%	118%
SSE Hydro	68%	65%	66%	78%	74%	74%	87%	65%	94%	87%	89%	90%	69%	67%	68%	66%	73%	64%	71%	62%	68%	62%	71%	66%	74%	69%
SSE Southern	81%	89%	90%	77%	82%	83%	72%	89%	82%	72%	75%	76%	81%	80%	79%	90%	83%	89%	81%	90%	83%	87%	79%	90%	83%	91%

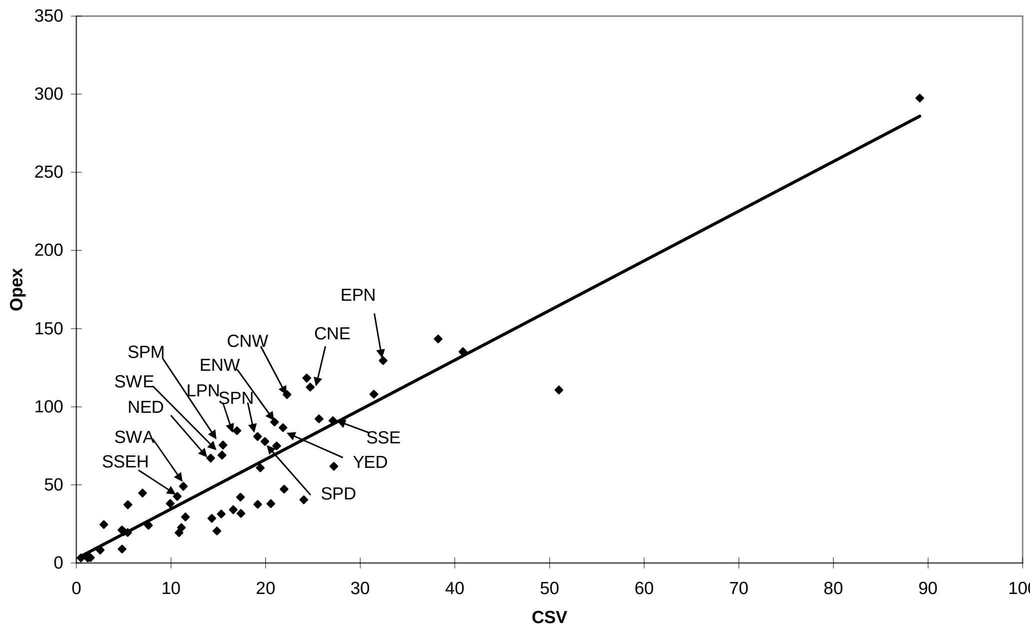
1.54. The results summary shows that the overall view of comparative performance remains broadly consistent accross the different assumptions and analysis methods used. The SSE and WPD DNOs consistently appear to be performing comparatively well in the analysis while the EDFE DNOs, CN West and SP Distribution consistently perform comparatively poorly.

International Comparison

1.55. We have undertaken a high level comparison of UK and US DNOs using data provided by Ofgem's economic advisor, Michael Pollitt. We limited our comparison to US DNOs located in the North Eastern States because the climate is most like that in the UK. Because of data issues the numbers were further limited to 36 of the 54 operating in the North Eastern States.

1.56. We undertook the analysis on both operational expenditure and total expenditure to try to identify any substitution effect with different reporting rules in the US and UK. We used a CSV of Network Length, Units Distributed and Customer Numbers as the driver for our analysis and undertook regression analysis and Data Envelopment Analysis (DEA). Figure 4 shows the results of the regression analysis with the UK DNOs labelled.

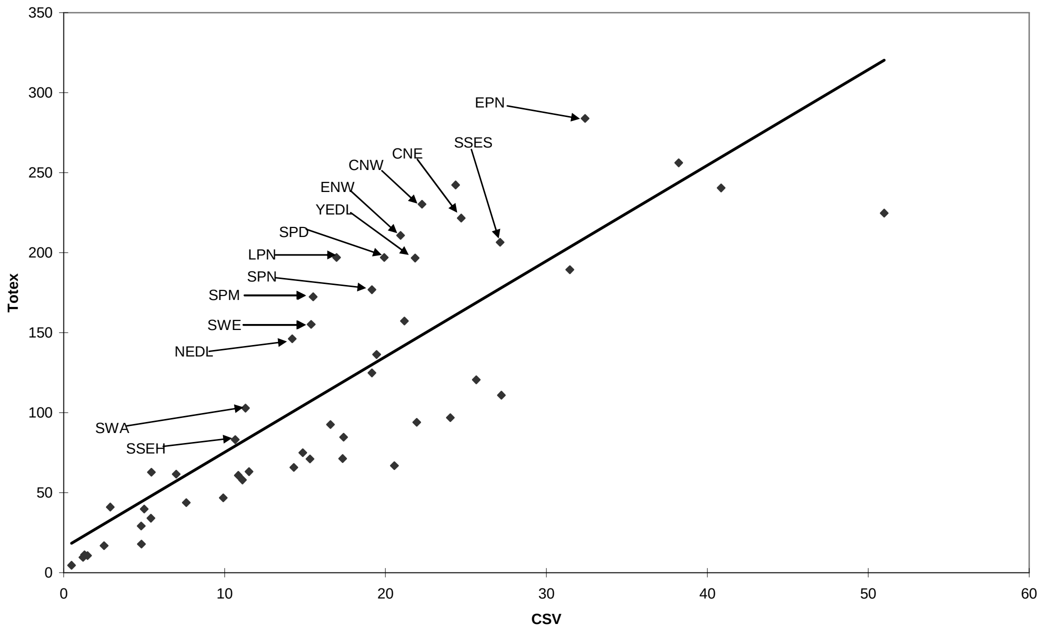
Figure 4: Regression of operational expenditure against DPCR4 CSV for US and UK DNOs



1.57. The results appear to show that the UK DNOs are comparable to the US DNOs and that they are as a group comparatively less efficient that those in the US. This suggests that there is scope for the UK DNOs to improve their efficiency.

1.58. Figure 5 shows the results of the regression of total costs against the same CSV. For this regression the largest US DNO was excluded because there was evidence that it was having a disproportionate impact on the regression estimates.

Figure 5: Results of the regression of total expenditure against the DPCR4 CSV for US and UK DNOs



1.59. The results show a similar story to that for operational expenditure, i.e. the model provides a reasonable fit to the data and the UK DNOs appear to have scope for efficiency improvements.

1.60. The results of the DEA analysis of UK and US DNOs indicate that generally the US DNOs might be more efficient than those in the UK. The results are summarised in Table 10 showing the numbers of DNOs that appear on the frontier and the average DEA scores.

Table 10 - Summary results of DEA analysis of operational and total expenditure using DPCR4 CSV as driver

	Operational expenditure		Total expenditure	
	Number of firms on frontier	Average DEA score	Number of firms on frontier	Average DEA score
All DNOs	4	0.66	4	0.74
UK DNOs	1	0.79	1	0.82
US DNOs	3	0.62	3	0.71

1.61. The overall results show that overall the US DNOs appear to performing better overall than the UK DNOs suggesting that those in the UK have scope for efficiency improvements.

Statistical Tests

1.62. We have conducted a series of statistical tests on the time series panel data models that we have estimated by ordinary least squares (OLS). These tests were selected in co-operation 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:

- Tests to ensure robust inference:
  - Breusch Godfrey test for serial correlation.
  - White test for heteroscedasticity.
- F-test for a constant cost driver coefficient over time.
- Ramsey RESET test for model mis-specification.
- Jarque-Bera test for normality.
- Cook's distance test for outliers.

1.63. These tests are discussed in more detail below. We also refer to the hypothesis test involved with each test and give the result as a "yes" or a "no" which is then used to present the results of these tests in Table 11 later in this appendix.

Tests to ensure robust inference

1.64. When an OLS regression (such as our time series panel data regressions) is run it produces estimates of the standard errors for each of the coefficients in the model. These standard errors are a measure of the uncertainty surrounding the estimates produced. These estimated standard errors can be used to perform hypothesis tests on the coefficients from the model. However, these standard errors will be biased and the results of any hypothesis tests will be misleading if there is:

- Serial correlation: this occurs when the residuals from the regression are not random over time. For example, a positive residual in one period might typically be followed by another positive residual in the next period. We have used the Breusch-Godfrey test to see if there is any serial correlation in the residuals from our regressions.
- Heteroscedasticity: this typically occurs when the variation in the residuals is very different over time. For example, if the residuals were very large in magnitude in some periods compared to others then we might think that the spread of residuals was not constant which would be an indication of heteroscedasticity. We have used the White test to check whether the variation in residuals is constant.

1.65. When either of the above symptoms is detected in a regression, it is possible to "correct" the standard errors of the coefficients so that any hypothesis testing can be conducted without obtaining misleading results. This is known as a "robust" estimation of the standard errors. The two tests are discussed in more detail below.

Breusch-Godfrey test

1.66. The Breusch-Godfrey test examines whether there is serial correlation in the residuals, which would mean that the standard errors of the coefficients are biased.

Hypothesis test:

1.67. The hypothesis that there is no serial correlation is rejected (Yes) if the residuals have serial correlation; otherwise there is not sufficient evidence to reject it (No).

White test

1.68. The White test examines whether the residual variance of a regression is constant (homoscedastic). If there is evidence of variation in the residual variance it implies that the standard errors of the coefficients are biased.

Hypothesis test:

1.69. The hypothesis that the residual variance is constant is rejected (Yes) if the residual variance exhibits significant variation; otherwise there is not sufficient evidence to reject it (No).

F-test for a constant cost driver coefficient

1.70. This F-test examines whether the slope coefficient on the cost driver is constant over time. If the effect of the cost driver is constant over time then time series panel data regressions can obtain better estimates than cross-sectional regressions.

Hypothesis test:

1.71. The hypothesis that the slopes are constant over time is rejected (Yes) if the slopes are not likely to be equal; otherwise there is not sufficient evidence to reject it (No).

Ramsey RESET test

1.72. The Ramsey Regression Equation Specification Error Test (RESET) test is a general test for model mis-specification. For example, the test might identify:

- Omitted variables - the equation does not include all relevant variables (drivers).
- Incorrect functional form - some or all of the variables (i.e. the costs and the driver) should be transformed to logs, powers, reciprocals, or in some other way.
- Correlation between the driver and the residuals, which may be caused, among other things, by measurement error in X.

Hypothesis test:

1.73. The hypothesis that the equation is correctly specified is rejected (Yes) if the equation likely to be mis-specified, otherwise there is not sufficient evidence to reject it (No).

Jarque-Bera test

1.74. The Jarque-Bera test is used to test whether the residuals are consistent with a normal distribution. Normality of residuals is not a necessity, but it is an indication of a well behaved model.

Hypothesis test:

1.75. The hypothesis that the data is from a normal distribution is rejected (Yes) if the data is not consistent with a normal distribution, otherwise there is not sufficient evidence to reject it (No).

Cook's distance test

1.76. Cook's distance is a test for outliers. An outlier is an observation that is different to the others in a dataset and has influence over the entire dataset's characteristics. In terms of regression analysis, variation in the data is necessary to carry out estimation. However, outliers can affect a model's overall fit and standard errors. Nevertheless, it is important not to exclude an outlier unless its values can be attributed to measurement error instead of a chance occurrence that reflects the underlying model. In short, the detection of an outlier provides a basis for investigating the data further, instead of excluding that observation.

Hypothesis test:

1.77. The hypothesis that the observation is not an outlier is rejected (Yes) if an observation is an outlier, otherwise there is no sufficient evidence to reject it (No).

Table 11 –Results of statistical tests on the core regressions

	Jarque-bera test	Cooks d distance test	Ramsay reset test	F-test	Breusch Godfrey test	White test
	Normality test	Outlier test	Model specification	Homogeneity test	Serial correlation	Heteroscadascity
DNOs Linear Model						
Top-Down	No	No	Yes	No	Yes	Yes
Single Group	2005-06 (Yes) 2006-07 (Yes) 2007-08 (No)	No	No	No	Yes	No
Group 1	2005-06 (No) 2006-07 (Yes) (marginal) 2007-08 (No)	No	No	No	Yes	No
Group 2	No	No	No	No	Yes	No
Group 3	2005-06 (No) 2006-07 (No) 2007-08 (Yes)	No	No	No	Yes	No
Faults Overhead	No	No	No	No	No	Yes
Faults Underground	No	No	Yes	No	Yes	No
Faults Quality of Service	No	No	No	No	Yes	Yes
Tree Cutting	No	No	No	No	Yes	No
Inspections & Maintenance	No	No	Yes	No	Yes	No
DNOs LogLog Model						
Top-Down	No	No	Yes	No	Yes	Yes
Single Group	No	No	No	No	Yes	No
Group 1	No	No	No	No	Yes	No
Group 2	No	No	No	No	Yes	No
Group 3	No	No	No	No	Yes	No
Faults Overhead	No	No	No	No	No	No
Faults Underground	No	No	Yes	No	Yes	No
Faults Quality of Service	No	No	No	No	Yes	No
Tree Cutting	No	No	No	No	Yes	No
Inspections & Maintenance	No	No	Yes	No	Yes	Yes
DNO Groups Linear Model						
Top-Down	No	No	No	No	Yes	No
Single Group	No	No	No	No	Yes	Yes
Group 1	No	No	No	No	Yes	Yes
Group 2	No	No	No	No	Yes	No
Group 3	No	No	No	No	Yes	No
DNO Groups LogLog Model						
Top-Down	No	No	No	No	Yes	No
Single Group	No	No	No	No	Yes	No
Group 1	No	No	No	No	Yes	No
Group 2	No	No	No	No	Yes	No
Group 3	No	No	No	No	Yes	No

1.78. There is not sufficient evidence to reject the F-test for a constant cost driver coefficient in all the specified regression models across the different cost activities. This implies that we are justified to assume that the cost drivers have a constant impact over the three years of data in our analysis.

1.79. Similarly, the outlier test does not suggest that any of the DNOs is an outlier in any of the three years of analysis.

1.80. With the exception of Top-Down, Faults Underground and Inspection & Maintenance cost activities in the DNOs regression models, the Ramsey test is not rejected for all the specified regression models across the different cost activities. There is not sufficient evidence to suggest that these models are mis-specified. However, further investigation is required in model specifications for the Top-Down, Faults Underground and Inspection & Maintenance equations in the DNO regressions.

1.81. The hypothesis that there is no serial correlation is rejected. The exceptions are Faults Underground and Faults Overhead for the DNOs linear and LogLog models respectively. We would expect the rejection of this hypothesis because in efficiency terms for instance, it is most likely that a DNO which is efficient in one given year will remain efficient in the next year. Consequently, the coefficient standard errors in the regressions are biased. We correct for serial correlation in the regression by applying the White period robust coefficient variance estimator, which is designed to accommodate arbitrary serial correlation and time-varying variances in the disturbances.

1.82. The hypothesis that the residual variance is constant is rejected in slightly less than one quarter of the regressions. Therefore, the coefficient standard errors are biased in these cases. We correct for this heteroscadascity in the regression by applying the White period robust coefficient variance estimator, which is designed to accommodate arbitrary serial correlation and time-varying variances in the disturbances.

1.83. We test for the normality of the residuals using the Jarque Bera test for each of the specified regression models. In the majority of cases we do not reject the null hypothesis of normality. However, in a number of instances where we have estimated models for a single year, namely Single group (2005-2006 and 2006-2007), Group 1 (2006-2007), and Group 4 (2007-2008) we reject the hypothesis of normality. The rejection of the Group 1 (2006-007) is marginal. We will investigate these results further.

Costs Excluded from the Comparative Benchmarking

1.84. Comparative analysis work represents the starting point for determining our cost baselines. Where comparative analysis is not appropriate because of the nature of the costs (e.g. where costs are only incurred by only one or a just a few of the DNOs) then we will use other methods to inform our baselines.

1.85. In such cases we will use a combination of the average costs for the years 2005-06 to 2008-09 or trend analysis for that period. We will then compare the results of that work to the forecasts presented by the DNOs, as for any costs, before we determine our view of an appropriate allowance for the DNOs.

1.86. Since the December Policy Paper we have had further discussions internally and with the DNOs to resolve which costs should and should be included in the comparative benchmarking. We have resolved the issue for some of those costs but for others we are still considering the most appropriate approach.

1.87. In Chapter 3 we summarised the costs excluded from the comparative benchmarking under three heading. The following tables provide additional details of the cost excluded in 2007-08.

Table 12 - Costs moved to Network Investment (£m)

	Vehicles & Transport	STE/ Plant & Machinery	Total
CN West	3.5	0.7	4.2
CN East	3.7	0.8	4.5
ENW	2.3	0.4	2.7
CE NEDL	2.5	0.3	2.8
CE YEDL	2.3	0.4	2.7
WPD S Wales	1.4	0.7	2.1
WPD S West	4.6	1.1	5.8
EDFE LPN	2.0	0.5	2.5
EDFE SPN	3.3	0.5	3.8
EDFE EPN	4.6	0.9	5.5
SP Distribution	4.4	0.3	4.6
SP Manweb	3.9	0.2	4.1
SSE Hydro	4.8	0.6	5.4
SSE Southern	9.2	1.0	10.1
Total	**52.6**	**8.3**	**60.9**

Table 13 - Costs being reviewed by the IT and Property Consultants (£m)

	IT & Telecoms	Non-Operational Capex IT	Property Management	Non-Operational Office Equipment	Non-Operational Property	Total
CN West	10.9	0.7	5.5	0.0	0.0	**17.1**
CN East	9.8	0.6	4.6	0.0	0.0	**15.0**
ENW	12.8	0.3	7.2	0.0	0.0	**20.3**
CE NEDL	6.4	1.0	2.8	0.3	0.2	**10.7**
CE YEDL	7.1	0.6	3.4	0.6	0.0	**11.7**
WPD S Wales	6.6	1.1	2.3	0.1	0.3	**10.4**
WPD S West	6.7	1.1	3.7	0.4	2.0	**13.9**
EDFE LPN	8.4	4.4	6.1	0.0	0.6	**19.5**
EDFE SPN	7.5	3.4	5.5	0.0	0.7	**17.1**
EDFE EPN	11.8	6.0	7.9	0.0	5.0	**30.7**
SP Distribution	7.3	2.1	4.1	0.3	0.1	**13.9**
SP Manweb	7.9	2.0	4.0	0.6	0.2	**14.6**
SSE Hydro	8.9	0.9	2.5	0.2	0.4	**12.9**
SSE Southern	10.0	0.8	4.0	0.1	2.5	**17.4**
Total	**122.1**	**25.0**	**63.6**	**2.5**	**12.0**	**225.2**

Table 14 - Costs considered unsuitable for Comparative Benchmarking (£m)

	Low Volume high cost Faults	Wayleaves	Insurance	Road Costs	Submarine Cables	Remote Location Generation	Unmetered Electricity
CN West	3.2	3.4	3.8	0.1	0.0	0.0	0.1
CN East	2.8	2.9	3.6	0.1	0.0	0.0	0.1
ENW	2.8	1.6	1.0	0.2	0.0	0.0	0.0
CE NEDL	2.2	1.7	2.3	0.0	0.0	0.0	0.0
CE YEDL	3.9	2.3	2.2	0.0	0.0	0.0	0.0
WPD S Wales	1.1	2.2	2.8	0.0	0.0	0.1	0.0
WPD S West	2.1	2.7	2.8	0.0	0.0	0.8	0.0
EDFE LPN	0.8	0.7	3.7	0.3	0.0	0.0	0.0
EDFE SPN	2.3	1.8	3.3	0.1	0.0	0.0	0.9
EDFE EPN	3.4	3.9	4.9	0.2	0.0	0.0	1.6
SP Distribution	0.7	2.0	2.9	0.0	0.0	0.0	0.0
SP Manweb	0.3	2.4	2.7	0.0	0.0	0.0	0.0
SSE Hydro	1.0	2.5	2.4	0.0	0.2	1.7	1.1
SSE Southern	1.6	2.7	5.8	0.0	2.6	0.0	1.1
Total	**28.2**	**32.8**	**44.2**	**0.9**	**2.8**	**2.6**	**4.8**

Appendix 6 - General reinforcement modelling

1.1. This appendix sets out further details of our methodology for modelling general reinforcement.

Approach to general reinforcement costs

1.2. Since the DPCR4 cost review a number of issues were identified with the previous modelling using customer numbers and units distributed. To address these concerns we have split load related investment assessment into three areas which have exhibited different costs and drivers. These areas are:

- customer specific expenditure (Demand Connections),
- secondary distribution (LV and HV) general reinforcement expenditure, and
- primary distribution (132kV and EHV) general reinforcement expenditure modelling.

1.3. For primary distribution general reinforcement a two stage modelling approach has been taken. However, N-2 schemes are excluded from the model due to their lumpy nature and high cost. These (N-2) schemes will be assessed separately on a scheme-by-scheme basis. EDFE LPN has also been excluded from the model due to the high cost and complexities associated with central London.

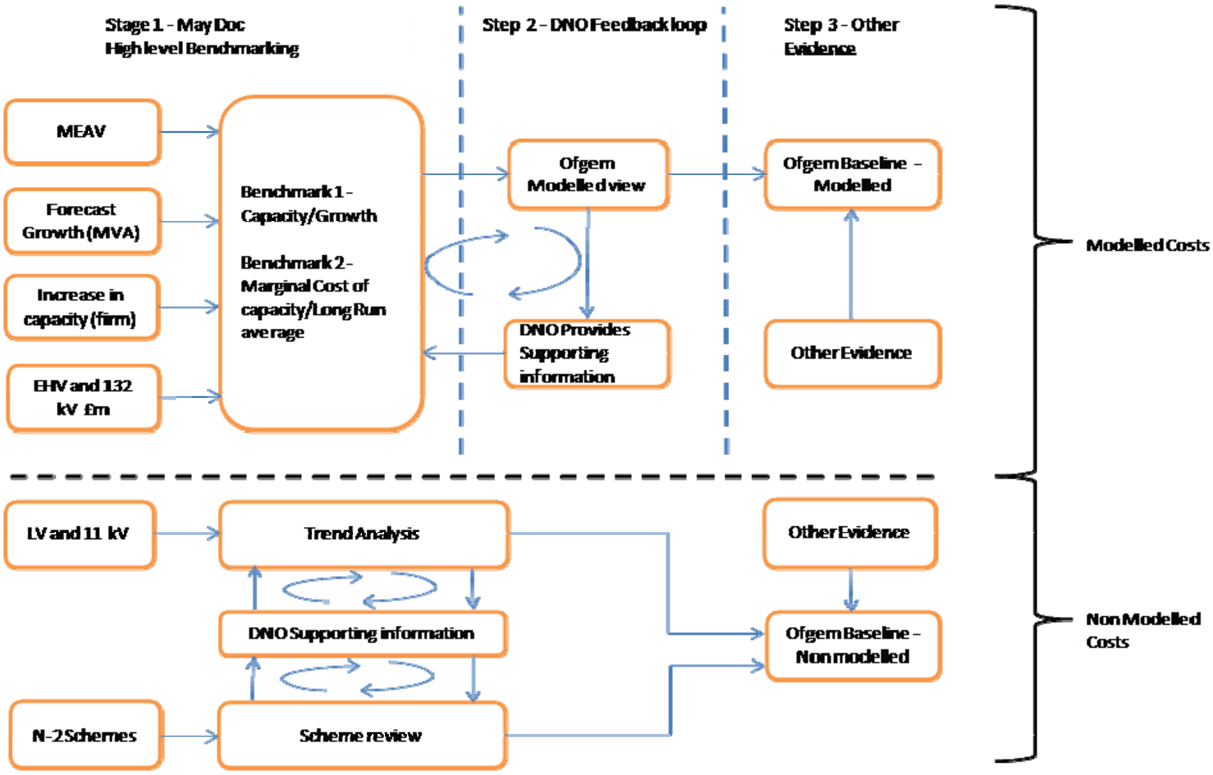
1.4. The primary distribution model addresses two key questions:

- are DNOs forecasting an appropriate amount of additional capacity given forecast demand growth, and
- is capacity being added at an appropriate cost?

1.5. We have decided to review the secondary (LV and HV) general reinforcement using a top down approach considering DPCR5 forecast expenditure against DPCR4 expenditure with support from certain related drivers, such as forecast load growth, and forecast new demand connections.

1.6. The overall process is set out in figure 1 below. The modelling discussed in this appendix relates to step one. Step two and step three of our assessment are discussed in chapter 4 of the main document.

Figure 1 – Approach to General Reinforcement Costs



1.7. The amount of general reinforcement expenditure modelled for each area is set out in table 1 below.

Table 1 - General reinforcement expenditure

DNO	Total General Reinforcement Expenditure Including Indirects £m	132kV and EHV Expenditure Including Indirects £m	N-2 Schemes Including Indirects £m	Other Schemes Removed	Forecast 132kV and EHV Expenditure Modelled £m	Percentage of 132kV and EHV Reinforcement Modelled	LV and HV Expenditure Including Indirects £m
CN West	169.5	145.6	21.3	--	124.3	85%	23.9
CN East	235.3	203.5	39.5	--	164.0	81%	31.8
ENW	138.9	104.1	42.8	--	61.3	59%	34.8
CE NEDL	64.2	42.1	2.7	--	39.4	94%	22.1
CE YEDL	69.2	44.5	18.6	--	25.8	58%	24.7
WPD S Wales	34.9	26.1	--	--	26.1	100%	8.8
WPD S West	41.8	33.4	--	--	33.4	100%	8.4
EDFE LPN	243.4	212.9	--	--	[redacted]		30.5
EDFE SPN	133.9	116.4	--	--	116.4	100%	17.5
EDFE EPN	327.8	288.8	--	--	288.8	100%	39.0
SP Distribution	75.7	42.9	--	7.1	35.8	83%	32.8
SP Manweb	106.1	95.2	--	--	95.2	100%	10.8
SSE Hydro	39.0	22.9	--	--	22.9	100%	16.1
SSE Southern	243.3	127.9	57.3	--	70.6	55%	115.4
Total	1,923.1	1,506.5	182.3	7.1	1,104.2	73%	416.6

132kV and EHV Load Related Expenditure

1.8. The model for 132kV and EHV general reinforcement benchmarks growth (ratio of capacity added to maximum demand growth) on individual schemes forecasted for reinforcement and the cost of adding the forecast capacity required to meet the demand. This model only takes into account growth driving expenditure and the model is, therefore, not affected by negative growth on other areas of the network.

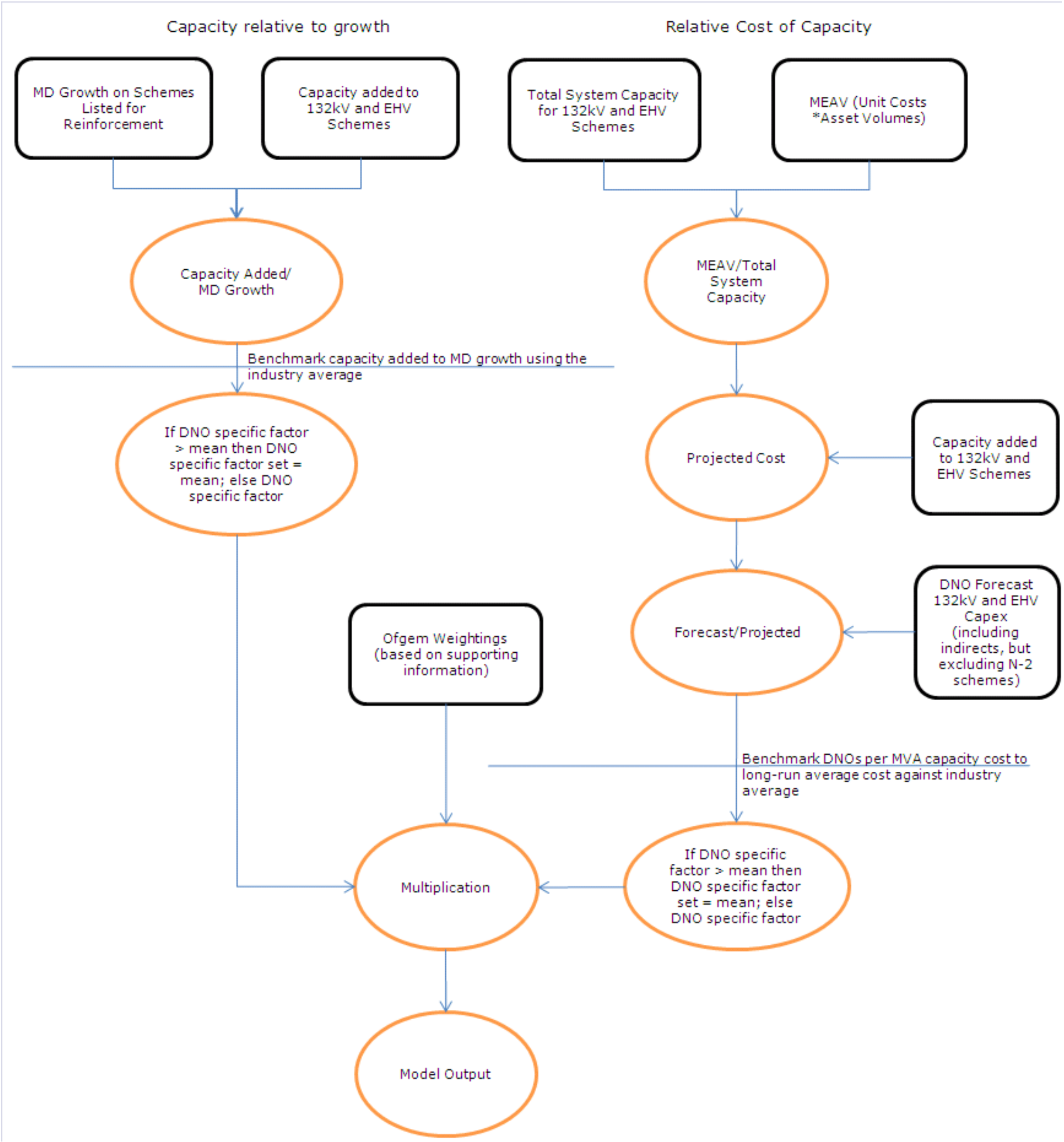
1.9. The model benchmarks DNO forecast 132kV and EHV general reinforcement in two stages:

- Ratio of capacity to be added to forecast maximum demand ('MD') growth on individual schemes listed for reinforcement, and

- Ratio of forecast cost per MVA of capacity to long run average cost per MVA of capacity.

1.10. The stages of the model are illustrated in figure 2 below.

Figure 2 - 132kV and EHV general reinforcement modelling



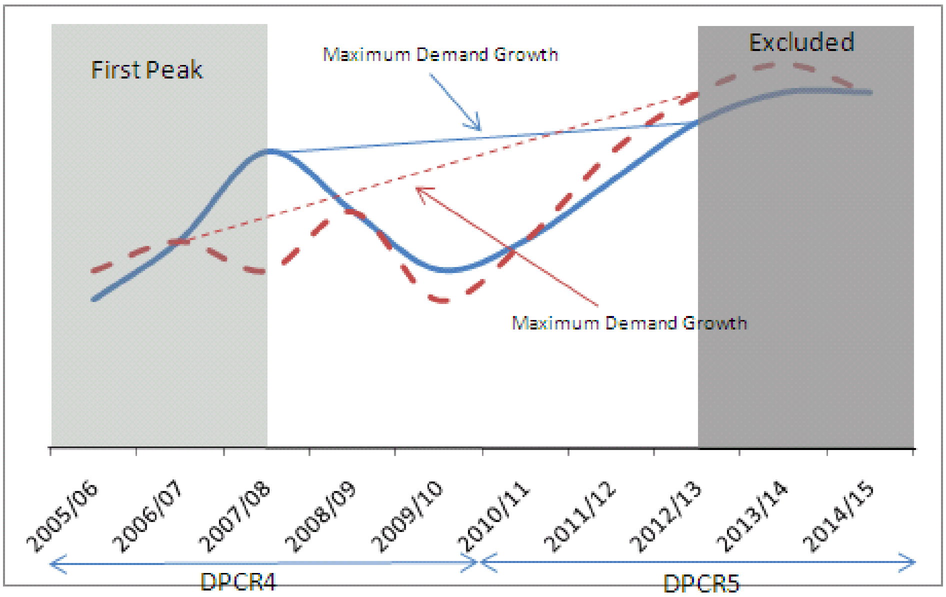
Variables used in the two stage model

Maximum demand

1.11. The growth in MD is calculated for individual schemes as the growth from the peak during the first three years of DPCR4 and the peak in MD at any point from the beginning of DPCR4 to two years before the end of DPCR5. This period was chosen to reflect the time lag between a DNO recording a sustained increase in MD and carrying out the actual investment in reinforcing i.e., for a substation with normal growth this period would encapsulate five years of growth and a two year lead time for investment. The choice of period also assumes that growth occurring prior to the MD peak in 2005-2008 would already have been considered for reinforcement during DPCR4. Where negative growth occurs from DPCR4 to DPCR5 the peak-to-peak method ensures that the MD growth is recorded as zero.

1.12. Figure 3 below illustrates the peak-to-peak method for calculating MD growth on individual schemes. Two examples schemes with possible MD growth patterns are shown in the figure.

Figure 3 – Example of the peak to peak maximum demand growth method



1.13. Only growth on substations or schemes that the DNOs plan on reinforcing are included in the model. Note: if reinforcement is required on a scheme which reached a critical point prior to the start of DPCR4, this will not be picked up in the MD growth figure (this relates to the assumption mentioned in the paragraph above).

1.14. Table 2 below shows: the MD growth used in the model; the N-2 maximum demand removed from the model; and, as a comparison, the MD on all substations with HV secondary voltage. The method for determining growth as described above was used to determine the maximum demand growth for all substations with HV secondary voltage, thus negative growth is not included.

Table 2 – DNOs' forecast maximum demand growth

DNO	Max Demand Growth	Maximum Demand Growth on N-2 Schemes	Adjusted Maximum Demand Growth	LTDS MD Growth on all Substations with HV Secondary
CN_West	105	--	105	259
CN_East	90	--	90	377
ENW	58	--	58	73
CE_NEDL	33	12	21	149
CE_YEDL	55	24	30	253
WPD_S_Wales	20	--	20	34
WPD_S_West	107	--	107	86
EDFE_LPN	[redacted]			
EDFE_SPN	74	--	74	26
EDFE_EPN	173	--	173	158
SP_Distribution	35	--	35	110
SP_Manweb	28	--	28	34
SSE_Hydro	6	--	6	114
SSE_Southern	156	79	77	399
Total	942	115	827	2,071

Capacity

1.15. Capacity added is the forecast firm capacity that will be added to the network through 132kV and EHV general reinforcement. However, a number of schemes were submitted, by various DNOs, where the DNO did not (or could not) provide related MD growth information. Including these schemes in the model would distort the results for other DNOs as it would increase the industry average. As such, the capacity added has been removed from the first stage of the model. The second stage of the model is unaffected by the lack of MD data as it benchmarks on the per MVA cost of capacity.

1.16. Where these schemes have been removed we expect the DNOs to provide supporting evidence to justify their expenditure on the additional capacity.

1.17. There are schemes with expenditure extending outside of DPCR5. Where this occurs, a proportion of capacity (based on expenditure) is removed from the second stage of the model (where the average costs are determined). For example, if £10m is being spent on a scheme, £5m during DPCR5 and £5m during DCPR6, and the scheme is forecasted to add 100MVA of system firm capacity then 50MVA will be removed from the forecast capacity added. This is to prevent the per MVA cost from being under reported. Only two DNO's (ENW and EDFE SPN) are affected by this and the amount of capacity removed is minor (5 MVA and 6 MVA respectively).

1.18. Total substation firm capacity is taken from table LR5 of the February FBPQ. This was chosen as it more comparable with the MEAV valuation, which is based on asset volumes from the February FBPQ and Ofgem's initial view on new build unit costs informed by PB Power.

Table 3 – DNOs' forecast for additional firm capacity[1]

DNO	Total System Firm Capacity	Capacity Growth	Capacity Growth from N-2 Schemes	Capacity on Schemes with No MD	Adjusted Capacity Growth
			(-)	(-)	(=)
CN_West	9,380	2,126	300	949	877
CN_East	13,194	2,795	843	966	986
ENW	13,898	765	4	18	743
CE_NEDL	7,317	773	360	--	413
CE_YEDL	14,234	766	357	--	409
WPD_S_Wales	5,332	300	--	--	300
WPD_S_West	9,077	350	--	--	350
EDFE_LPN	[redacted]				
EDFE_SPN	10,877	964	--	264	700
EDFE_EPN	17,730	2,202	--	996	1,206
SP_Distribution	7,351	466	--	200	266
SP_Manweb	8,091	796	--	45	751
SSE_Hydro	2,421	80	--	--	80
SSE_Southern	19,756	1,107	253	60	794
Total	138,657	13,488	2,117	3,498	7,873

Expenditure

1.19. The expenditure used in the model is the DNOs' forecast expenditure on 132kV and EHV general reinforcement including indirects,[2] but with N-2 scheme expenditure (including indirects) removed[3].

[1] SP Distribution has forecast to add two hundred MVA of firm capacity which is directly associated with the transmission network and will be owned by the transmission company. As such, this firm capacity has been removed from SP Distribution's firm capacity added. This is recorded in the column 'Capacity on Schemes with no MD'.
[2] Expenditure was included on a fully absorbed basis to maintain consistency with the original unit costs used in the modelling.
[3] Capacity from a N-2 scheme that adds to N-1 firm capacity is left in the model. The proportion of the expenditure on this scheme is added to the model.

Table 4 – Forecast expenditure for 132kV and EHV general reinforcement during DPCR5

DNO	132kV and EHV Expenditure Including Indirects £m	N-2 Schemes Including Indirects £m	Other Schemes Removed	Forecast 132kV and EHV Expenditure Modelled	Percentage of 132kV and EHV Reinforcement Modelled
CN West	145.6	21.3	--	124.3	85%
CN East	203.5	39.5	--	164.0	81%
ENW	104.1	42.8	--	61.3	59%
CE NEDL	42.1	2.7	--	39.4	94%
CE YEDL	44.5	18.6	--	25.8	58%
WPD S Wales	26.1	--	--	26.1	100%
WPD S West	33.4	--	--	33.4	100%
EDFE LPN	212.9	--	--	[redacted]	
EDFE SPN	116.4	--	--	116.4	100%
EDFE EPN	288.8	--	--	288.8	100%
SP Distribution	42.9	--	7.1	35.8	83%
SP Manweb	95.2	--	--	95.2	100%
SSE Hydro	22.9	--	--	22.9	100%
SSE Southern	127.9	57.3	--	70.6	55%
Total	1,506.5	182.3	7.1	1,104.2	73%

MEAV

1.20. 132kV and EHV MEAV is calculated as the product of the asset volumes supplied in the February FBPQ (February 2009) and Ofgem's initial view on new build unit costs.

Table 5 - 132kV and EHV MEAV

DNO	132kV and EHV MEAV £m	Total MEAV £m	Proportion of 132kV and EHV MEAV of Total MEAV
CN_West	1,826	9,341	20%
CN_East	2,778	11,039	25%
ENW	2,475	9,543	26%
CE_NEDL	1,405	6,343	22%
CE_YEDL	2,028	8,918	23%
WPD_S_Wales	1,375	4,950	28%
WPD_S_West	1,822	6,777	27%
EDFE_LPN	1,340	6,616	20%
EDFE_SPN	1,917	8,127	24%
EDFE_EPN	3,326	13,502	25%
SP_Distribution	1,469	8,455	17%
SP_Manweb	1,812	6,927	26%
SSE_Hydro	1,129	4,778	24%
SSE_Southern	3,284	12,262	27%

Model stages

Ratio of capacity added to maximum demand growth benchmark ('Capacity to MD Growth')

1.21. In the first stage of the general reinforcement model the ratio of capacity to be added against MD growth is benchmarked against the industry average ratio. This benchmark highlights DNOs that are adding over the industry average capacity to meet their MD growth forecast.[4]

1.22. There are a number of valid reasons why this ratio may be high, such as:

- capacity being added in large chunks due to standard equipment sizes,
- the five year growth window does not capture historical growth which will also be driving the need for investment, and
- the marginal cost of capacity may be very low making it economic to add a relatively large amount of capacity once the decision to reinforce is made.

[4] The ratio provides and indication. There may be numerous reasons why the DNOs are adding capacity above what is indicated by the industry average.

1.23. We would expect the DNOs to provide further supporting information in relation to this.

Ratio of DPCR5 average MVA unit cost of capacity to long-run average unit cost of capacity ('Relative Cost of Capacity') benchmark

1.24. The second stage of the 132 kV and EHV general reinforcement model benchmarks a DNO's ratio for its DPCR5 average cost of adding an MVA of firm capacity to its long-run average cost of an MVA of firm capacity against the industry's average ratio. The long-run average is calculated as the DNO's MEAV of all 132kV and EHV assets divided by the DNO's total system firm capacity.

1.25. By using the DNOs' own long-run costs in the benchmarking process, the DNO's particular network characteristics are taken into account i.e., where a DNO has a sparse network, and hence long lines with more substations, this will be represented in their historical costs and therefore in their ratio of forecast DPCR5 expenditure to their long-run capacity costs.

1.26. The DNO specific ratio is then benchmarked against the industry average ratio. This benchmark indicates whether the DNO's forecast cost for adding additional capacity is high, average, or low relative to its historical cost of adding a MVA of capacity.

Results

1.27. As the two stages of the model are independent, a relatively low ratio, compared to the average, for one stage does not offset a relatively high ratio for the other stage. However, the outputs of each stage need to be considered together to give an overall indication as to the relative level of expenditure forecast for DPCR5 by each DNO.

1.28. For example, consider a DNO that is adding a relatively large amount of capacity, but its per MVA cost is low, then in the second stage of the model it would come out as being below the industry average. However, as it is adding a relatively high amount of capacity in the first stage of the model, the DNO needs to provide supporting evidence for the additional capacity.

1.29. The two stage modelling highlights areas where a DNO will have to provide further evidence to convince us of the investment need. In particular it highlights:

- Which DNOs are adding capacity over what the industry average indicates, and
- Which DNOs' per MVA cost ratio is above the industry average.

1.30. Table 6 shows the results of both stages of the model. Looking at the ratio of capacity added to forecast growth in MD there are six DNOs (ENW, CE NEDL, CE YEDL, WPD S Wales, SP Manweb and SSE Hydro) that are forecasting the installation of higher than the average amount of capacity related to the MD growth they have forecast.

1.31. In addition, while CN's ratio of capacity added to MD growth is not high compared to the industry average it is adding a substantial amount of capacity to both CN West and CN East on schemes where they are unable to quantify MD growth without detailed system studies. If the capacity added for these schemes were included in the model CN's ratios would be well above the industry average.

1.32. The average ratio of 12 implies that on average 12 MVA of firm capacity is added for every 1 MVA of maximum demand growth on the schemes identified for reinforcement.

Table 6 – Model results

DNO	Capacity added relative to		Relative MVA Unit Costs	
	Ratio	% of Average	Ratio	% of Average
CN West	8.3	Very Low	0.35	Very Low
CN East	10.9	Low	0.40	Low
ENW	12.8	Average (+)	0.45	Low
CE NEDL	19.8	Very High	0.50	Average (-)
CE YEDL	13.5	High	0.45	Low
WPD S Wales	15.0	High	0.34	Very Low
WPD S West	3.3	Very Low	0.48	Average (-)
EDFE LPN				
EDFE SPN	9.4	Low	0.69	Very High
EDFE EPN	7.0	Very Low	0.70	Very High
SP Distribution	7.5	Very Low	0.67	Very High
SP Manweb	27.1	Very High	0.53	Average (+)
SSE Hydro	12.8	Average (+)	0.62	High
SSE Southern	10.2	Low	0.50	Average (-)
Average	**12.1**		**0.51**	

1.33. There are four DNOs showing a high or very high ratio of DPCR5 average capacity cost to their long-run cost of capacity (EDFE SPN, EDFE EPN, SP Distribution and SSE Hydro), indicating relatively high unit costs for install an MVA of capacity[5].

1.34. The average ratio of 0.5 implies that the average cost of installing an additional MVA of firm capacity costs half the long-run cost of an installed MVA of firm capacity.

N-2 schemes

1.35. For the February FBPQ each DNO was requested to provide its required N-2 schemes during DPCR5. As stated earlier, N-2 schemes normally have high costs and often arise from regulatory requirements to ensure security of supply.

1.36. We will assess N-2 schemes on a scheme-by-scheme basis with DNOs providing supporting evidence as to the requirement and costing of these schemes. This assessment will feed into Ofgem's baseline view for each DNO. In the case of large N-2 schemes, DNOs may be required by Ofgem to commit to providing output measures for these.

1.37. CN West, CN East, ENW, CE NEDL, CE YEDL and SSE Southern have all reported that they will be undertaking N-2 schemes during DPCR5.

LV and HV general reinforcement

1.38. At a high level a correlation between economic growth and LV and HV general reinforcement can be seen. Based on current economic conditions and forecasts we do not consider that economic growth during DPCR5 will significantly exceed that exhibited in DPCR4. Therefore, we consider that LV and HV general reinforcement expenditure during DPCR4 is a good indicator of the expenditure required by each DNO during DPCR5.

Results

1.39. Table 7 shows the forecast expenditure by each DNO during DPCR4 and DPCR5. The overall increase in LV and HV general reinforcement expenditure from DPCR4 to DPCR5 is 13.2 per cent. This increase is predominantly driven by five DNOs: EDFE EPN, EDFE LPN, ENW, SP Distribution and SSE Southern.

[5] Note; while the average cost does not take in all of the factors that affect the cost of installing the extra capacity (such as line length), because the ratio is based on the historical cost of the DNO the type of network is implicitly taken into account.

1.40. The DNOs' forecast changes in demand connections and estimated LV and HV units distributed from DPCR4 to DPCR5 are included in the table, with the majority of DNOs forecasting falls in demand connections and units distributed.

Table 7 – LV and HV general reinforcement forecast expenditure and drivers

DNO	Expenditure £m		Change in Expenditure	Change in Demand Connections	Estimated LV and HV units distributed
	DPCR4	DPCR5			
CN WEST	20.7	21.0	1.3%	(29.3%)	(5.8%)
CN EAST	25.9	26.3	1.3%	15.4%	(3.3%)
ENW	16.5	24.6	48.8%	(24.2%)	(4.8%)
CE NEDL	18.2	19.2	5.6%	(11.0%)	2.0%
CE YEDL	22.0	22.4	1.9%	(7.4%)	0.8%
WPD S Wales	7.2	7.3	1.4%	(25.5%)	2.1%
WPD S West	6.3	6.9	9.5%	(16.3%)	1.7%
EDFE LPN	22.8	30.5	33.8%	1.1%	(4.2%)
EDFE SPN	17.9	17.5	(2.2%)	(9.1%)	(1.5%)
EDFE EPN	26.7	39.0	46.1%	14.8%	(1.8%)
SP Distribution	23.9	28.1	17.6%	(22.5%)	(5.2%)
SP Manweb	10.9	9.5	(13.4%)	(12.8%)	(5.2%)
SSE Hydro	11.5	12.5	8.7%	(18.1%)	(3.2%)
SSE Southern	87.3	95.6	9.5%	(10.6%)	(1.8%)
Total	317.9	360.3			

1.41. Based on the current and forecast economic conditions, the DNOs' units distributed and demand connection forecasts; we consider that there is little evidence to support significant increases in LV and HV general reinforcement allowance in DPCR5, over DPCR4.[6] As such, any DNO which has indicated a requirement for a significant increase in LV and HV general reinforcement will need to provide strong supporting evidence to justify the increase.

[6] While certain areas within a network might be experiencing growth, we do not consider that the number of these areas or their impact would be significantly different for DPCR4.

Appendix 7 - Asset replacement modelling

Approach to asset replacement costs

1.1. One of the main drivers of network investment expenditure is the degradation of assets installed on the distribution networks. Assets generally fall into two camps: those that are allowed to fail in service and those that are replaced before failure. For those assets that are replaced before failure the DNO should assess replacement need based on asset condition information.

1.2. All DNOs are now committed to collecting detailed asset specific condition information for certain asset categories. Some DNOs are more advanced in the data collection process than others.

1.3. Where detailed asset condition information is available this can be used to derive an asset health index for each asset category. Some DNOs have combined asset health indices with assumptions regarding degradation rates to forecast asset replacement volumes. Other DNOs use age based asset replacement modelling in building up their forecast business plans. This usually relies on assuming a mean asset life, and a standard deviation around this life, for each asset category. These are updated as further information about the age of replaced assets and condition information comes to light.

Asset replacement model

1.4. We have developed a model to address the key question:

- Are volumes of replacement being forecast by each DNO consistent with what has been done in the past or with what industry as a whole is planning to do in future?

1.5. To address this question we are using a standard age based asset survivor model. This model can be used to forecast a volume of asset replacement for each DNO. The model has been used extensively by Ofgem and its consultants at a number of previous price controls. Most DNOs also use an equivalent model as a sense check for their condition based forecasts, to produce forecasts where there is a lack of specific condition information and as a long term forecasting tool. The model which we are using has been audited by PB Power.

1.6. The model applies a distribution curve representing the probability of an asset requiring replacement to the DNOs' asset age profiles to derive forecast replacement volumes. The model's outputs are mechanically derived from the input data. We intend to share the workings of the model with the DNOs to avoid any misunderstanding concerning the nature of the calculations and to allow discussion to centre on the outputs of the model and explanation of differences between the model's volume output and the DNOs' forecast business plan submissions.

1.7. We consider this modelling to be a valuable tool in assessing asset replacement expenditure forecasts. However we understand that this modelling has limitations where lives used do not fully take account of factors such as specific DNO issues, type faults, equipment obsolescence etc. Where a DNO considers this to be the case the onus will be on the DNO to present compelling bottom-up evidence of the investment need.

Modelling methodology

1.8. In DPCR4 age based modelling was largely based on benchmarking of the mean asset lives and standard deviations reported by the DNOs. In DPCR5 we have developed the model to calculate lives based on historical and forecast volumes of replacements. In order to do this we are using the "Poisson" distribution to represent asset lives. This defines the standard deviation to be the square root of the mean life. Specifically we are using a variation of the model to calculate:

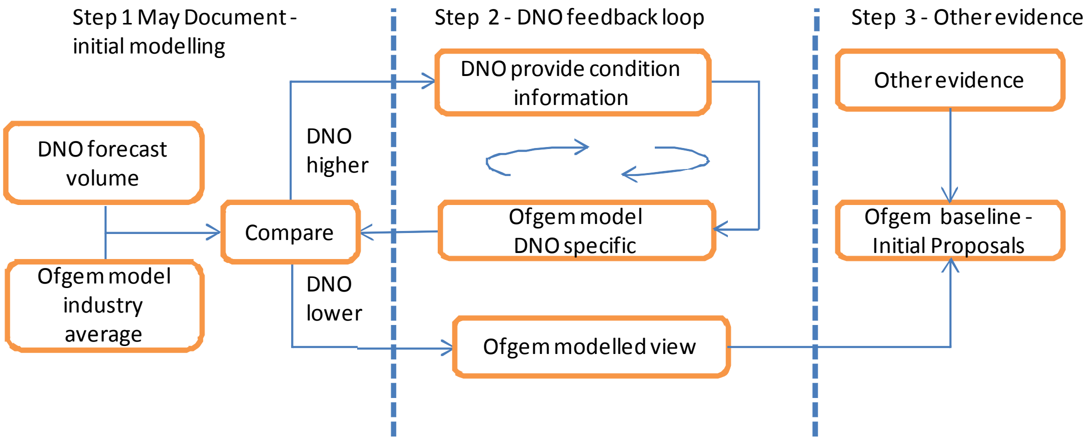
- The lives that when entered into the model using the asset age profile at 2004-05 give output volumes equal to those actually replaced by the DNOs in DPCR4, and

- The lives that when entered into the model using the asset age profile at 2007-08 give output volumes equal to those forecast by the DNOs to be replaced in DPCR5.

1.9. These derived historical and forecast lives can be calculated for an individual DNO or for the industry as a whole. Within our modelling it has been assumed that across the industry asset lives can either be maintained at the levels achieved in DPCR4 or longer lives can be achieved in DPCR5 through improved asset management. We have therefore taken the higher of the lives achieved across the industry in DPCR4 and those forecast for DPCR5. This new set of lives is then inputted into a model along with each DNO's individual asset age profile to give a DNO modelled volume.

1.10. Our overall approach to assessing asset replacement investment needs is shown in figure 1 below. Our asset replacement modelling is represented by stage one in this diagram. As shown this is prior to updating our modelled view with DNO supporting evidence such as condition information and any further evidence.

Figure 1 - Asset replacement assessment methodology



1.11. The modelling in stage one of this methodology is shown in summary in figure 2 below and in more detail in figure 3

Figure 2 - Asset replacement modelling summary

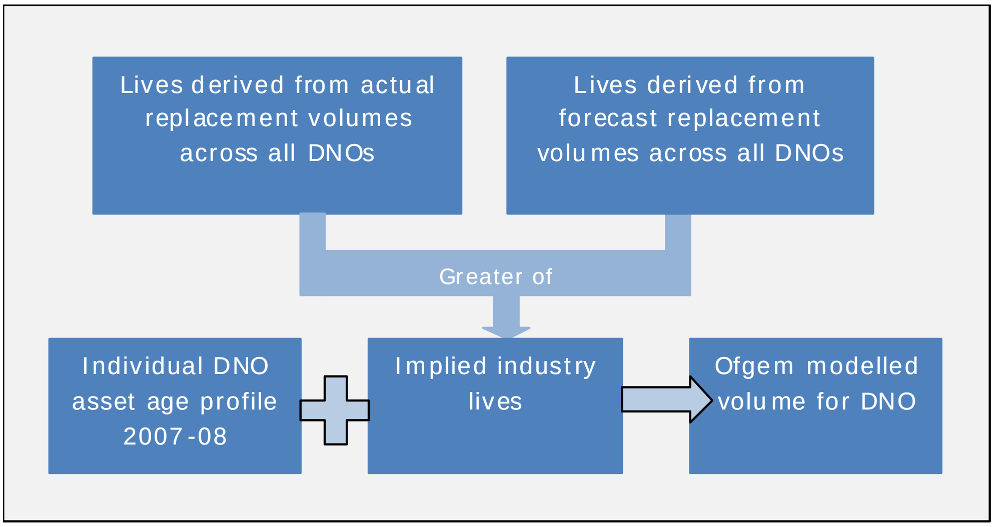
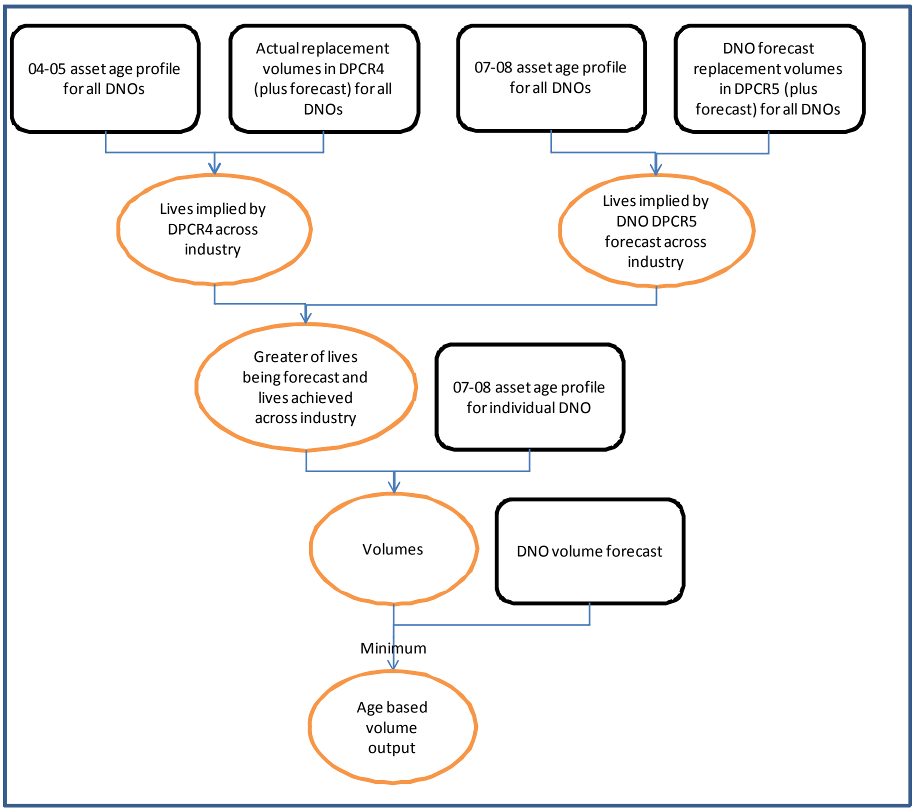
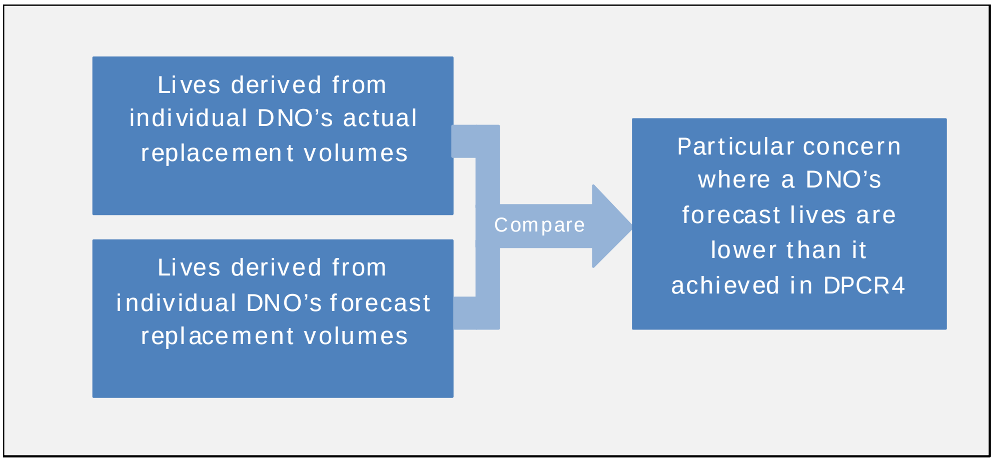


Figure 3 - Asset replacement model



1.12. In addition to the modelling described above we have analysed the lives implied by each individual DNO's implied historical and forecast lives.

Figure 4 – Analysis of DNOs' implied lives



1.13. The modelling described has been used to highlight areas where a DNO will have to provide further evidence to convince us of the investment need. In particular it has highlighted:

- Where DNOs are forecasting lower mean lives in DPCR5 than they achieved in DPCR4,
- Where DNOs are forecasting lower mean lives in DPCR5 than are being achieved across the industry, and
- Where DNOs are forecasting lower mean lives in DPCR5 than are being forecast across the industry.

1.14. The modelling carried out so far gives a purely volume based output. Where the model forecasts different volumes of asset replacement to those in the DNOs' forecasts we will be seeking to understand those differences. We will require DNOs to provide very detailed and robust information such as asset condition information, details of any identified type fault, full details of any work programmes etc. Where evidence provided is not considered to be of a high enough standard we will place more weight on the output of the model.

1.15. We are carrying out a separate unit cost assessment which we will use to derive expenditure allowances from our adjusted volumes. The results of the unit cost assessment will be presented in our Initial Proposals.

1.16. As part of the DPCR5 settlement the DNOs are required to provide a range of outputs that relate to asset replacement requirements, including a measure based on asset health indices and asset fault rates. As part of our assessment of the DNOs' forecasts we will consider the quality of their proposed outputs and the data behind these.

Modelling results

1.17. The modelled volume outputs can be compared with the DNO forecast volumes in two ways:

i. As pure volumes, or

ii. As volumes multiplied by a consistent set of unit costs, thereby giving an indication as to the materiality of the effect of the difference in volumes on expenditure (but without making an explicit assessment of unit costs).

1.18. The second option for the presentation of results has the advantage that aggregation of results across asset categories is more meaningful as the units are consistent. We have used this method in the main document and in Figures 5 to 9 below to apply bands ranging from "very low" to "very high" to categorise the DNOs' volume forecasts.

Figure 5 - DNO asset replacement forecasts - Supports

Supports	LV	HV	EHV	132kV
CN_West	Low	Low	Very high	Very high
CN_East	Low	Average	Very high	Very low
ENW	Very high	Very high	Very high	Very high
CE_NEDL	Average	Low	Very high	Very high
CE_YEDL	Average	Low	Very low	Very high
WPD_S_Wales	High	Very high	Very high	Very high
WPD_S_West	Very high	Very high	High	Very high
EDFE_LPN			Very low	Very high
EDFE_SPN	Low	Low	Very low	Very low
EDFE_EPN	High	Low	Very low	Very low
SP_Distribution	Very low	Low	Low	
SP_Manweb	Very high	Low	Very high	Very low
SSE_Hydro				
SSE_Southern				

Figure 6 - DNO asset replacement forecasts - Overhead lines (OHL)

OHLs	Services	Mains	HV	EHV	132kV
CN_West	Low	High	Very high	Very high	Very high
CN_East	Average	Very high	Very high	Very high	Very high
ENW	Very low	High	Very low	Low	Low
CE_NEDL	Very low	Very high	Low	High	Very high
CE_YEDL	Very low	Very high	Very high	Low	Very high
WPD_S_Wales	Very high	Very high	Low	Average	Very high
WPD_S_West	Very high	Low	Low	Low	Very high
EDFE_LPN				Very low	Very high
EDFE_SPN	Very low	Very low	Very low	Very low	Average
EDFE_EPN	Very low	Very low	High	High	Average
SP_Distribution	Very low	Low	Low	Low	
SP_Manweb	Very low	Very high	Average	Very high	High
SSE_Hydro					
SSE_Southern					

Figure 7 - DNO asset replacement forecasts - Cables

Cables	Services	Mains	HV	EHV	132kV
CN_West	Very high	High	Very high	Very high	Low
CN_East	Very high	Very high	Very high	Very high	Very high
ENW	Very low	High	Low	High	High
CE_NEDL	Very high	Low	High	Very high	Very high
CE_YEDL	Very high	Very high	High	High	Very high
WPD_S_Wales	Very high	Very high	Very high	Very high	Very high
WPD_S_West	Very high	Very high	Very high	High	Very high
EDFE_LPN	Very low	Very low	Very low	Very low	Very low
EDFE_SPN	Very low	Very low	Very low	Very low	Very high
EDFE_EPN	Very low	Very low	Low	Very low	Very low
SP_Distribution	Very high	Low	Very high	Very high	
SP_Manweb	Very high	Very high	Very high	Very high	Very high
SSE_Hydro	Very high	Very low	Very low	Very high	
SSE_Southern	Very high	Very high	Average	Very low	Very high

Figure 8 - DNO asset replacement forecasts - Switchgear

Switchgear	LV	HV	EHV	132kV
CN_West	Very high	Average	Low	Average
CN_East	Very high	High	Low	High
ENW	Very low	Average	Low	Very high
CE_NEDL	Very high	High	Low	Very high
CE_YEDL	Very high	Low	High	Very high
WPD_S_Wales	Very high	High	High	Very high
WPD_S_West	Very high	Low	Average	Low
EDFE_LPN	Very high	Low	Average	Low
EDFE_SPN	Very low	Very high	Very high	Average
EDFE_EPN	Very high	Very high	Very high	Average
SP_Distribution	Very high	Average	Average	
SP_Manweb	Very high	Average	High	Low
SSE_Hydro	Very low	Low	Very high	
SSE_Southern	Very high	Low	Low	Very high

Figure 9 - DNO asset replacement forecasts - Transformers

Transformers	HV	EHV	132kV
CN_West	High	Low	Low
CN_East	Very high	Low	Low
ENW	Low	Average	Very high
CE_NEDL	Very high	Very high	Very high
CE_YEDL	Very high	Very high	Average
WPD_S_Wales	Very high	High	High
WPD_S_West	Very high	High	Very high
EDFE_LPN	Low	Very low	Very low
EDFE_SPN	Very low	Low	Low
EDFE_EPN	Very low	Low	Very low
SP_Distribution	Very low	Very high	
SP_Manweb	Low	Very high	High
SSE_Hydro	Very high	High	
SSE_Southern	Low	High	High

1.19. Alongside this document we have published a spreadsheet which also forms part of this appendix (see associated documents). This spreadsheet gives greater detail regarding the historical and forecast lives calculated. It also gives greater detail of the reductions of pure volumes currently output by the model.

1.20. The additional spreadsheet shows that all DNOs have asset categories in which they have forecast higher replacement volumes than our model. Based on an initial view of unit costs we have provided the DNOs with an initial indication of the asset categories where we consider the reduction will be more material. Where this is the case the DNOs will need to provide additional evidence to convince us of the investment need.

Appendix 8 - Input prices: further details from the CEPA study

1.1. Chapter 6 provided a high level summary of the results obtained from CEPA's analysis of input prices. This appendix provides further details on:

- the assumptions behind their forecasts - both in terms of defining the scenarios and the composition of DNOs' costs, and
- the results of their analysis at a more disaggregated level.

Scenarios developed

1.2. CEPA conducted its analysis for three scenarios of macroeconomic performance. They describe these scenarios as follows:

- Scenario One, Optimistic Case – In this scenario, a sharp fall in GDP during 2008-09 is followed by a swift recovery and a peak in growth during 2011-12. The economy settles around its trend growth rate of the boom years 1998-2007 (2.8 per cent per annum) and economic activity is high throughout DPCR5.
- Scenario Two, Prolonged Crisis – In this scenario the UK economy contracts from 2008-09 to 2010-11. The recovery in 2011-12 is sharp, but the economy settles into a lower trend growth rate (2.2 per cent per annum) due primarily to increased regulation of financial services, and also to a sharp decline in public expenditure necessary to restore balance to the public finances.
- Scenario Three, Deflation Trap – In this case GDP contracts for three successive years and the rate of recovery is much slower than in either of the two alternative scenarios. As the UK economy struggles to adjust to a new economic environment in which financial services are no longer its main source of value-added creation, it settles to a trend growth rate that is half the rate observed during the boom years (that is, 1.4 per cent per annum).

1.3. The report states that these scenarios broadly correspond to V-, U- and L-shaped recessions. The table below contains the GDP growth assumptions in each of these scenarios.

Table 1 - CEPA's GDP growth forecasts (Per cent per annum)

	Scenario 1	Scenario 2	Scenario 3
2008/09	-3.2	-1.8	-1.8
2009/10	-1.5	-3.5	-3.0
2010/11	2.6	-1.3	-2.0
2011/12	3.7	3.7	-1.0
2012/13	3.0	2.6	1.0
2013/14	2.9	2.3	1.4
2014/15	2.8	2.2	1.4

1.4. To complement each of the GDP scenarios, CEPA also created forecasts of RPI inflation that they used for forecasting input price inflation relative to the RPI i.e. real price effects. These RPI forecasts are summarised in the table below.

Table 2 - CEPA's RPI inflation forecasts (Per cent per annum)

	Scenario 1	Scenario 2	Scenario 3
2008/09	0.0	0.0	0.0
2009/10	-2.0	-2.3	-2.7
2010/11	2.7	0.9	-2.5
2011/12	3.4	2.5	-1.2
2012/13	3.0	4.0	0.1
2013/14	2.9	4.4	1.0
2014/15	2.8	4.7	1.5

1.5. These forecasts of RPI played a key role in producing their forecasts of input price inflation. They examined the historical relationship between the relevant input price inflation, and then combined this relationship with the RPI forecasts above to generate their forecasts of input price inflation.

Weightings and data sources used to develop forecasts

1.6. CEPA analysed the February FBPQ data and consulted a specialist engineer to identify the inputs in each area of expenditure and their relevant weights. They also examined which indices could be used as the basis for forecasting inflation in these costs for DPCR5. The tables below present the weights and the indices used for forecasting.

Table 3 - Weights and data sources for operating expenditure inputs

Input	Proportion of costs (%)	Index	Source
General labour	45.0	Private Sector Average Earnings Index (including bonus)	ONS Average Earnings data
Contractor labour (opex)	35.0	Premium to general labour wage inflation	
Materials – general	10.0	BCIS building costs materials index	BCIS
Other	10.0	RPI	ONS RPI index

Table 4 - Weights and data sources for capital expenditure inputs

Input	Proportion of costs (%)	Index	Source
General labour costs	50.0	Private Sector Average Earnings Index (including bonus)	ONS Average Earnings data
Specialised labour costs	15.0	Premium to general labour wage inflation	
Materials – general	10.0	BCIS general building costs index	BCIS
Materials – specialised	15.0	BEAMA Basic materials electrical index	BERR
Equipment/ Plant costs	10.0	ONS Electrical machinery and apparatus	ONS

1.7. For contractor labour (opex) and specialised labour costs, the study forecasted inflation in these costs by applying a premium to general wage inflation. The size of this premium depended on the scenario. The table below provides the premiums for each of their scenarios.

Table 5 - Wage growth premium for contracted and specialised

	Premium (% per annum)
CEPA Scenario 1	0.0
CEPA Scenario 2	-0.5
CEPA Scenario 3	-1.0

1.8. They expect a smaller premium in scenarios two and three as they expect a longer recession to weaken the bargaining power of contractors. The report provides more details on the reasoning behind these premiums.

Disaggregated results

1.9. The table below presents the CEPA forecasts for these different cost components over the DPCR5 period.

Table 6 - CEPA forecasts of average real input price inflation (Per cent per annum) for the DPCR5 period (2010-11 to 2014-15)

	Scenario 1	Scenario 2	Scenario 3
General labour costs	1.1	0.9	2.3
Specialist labour	1.1	0.4	1.3
Materials – general	1.3	1.2	1.8
Materials – specialised	0.9	0.6	3.6
Equipment/ Plant costs	-1.9	-1.9	-2.2
Other	0.0	0.0	0.0
Opex	0.9	0.7	1.7
Capex	0.9	0.6	1.8
Total	0.9	0.6	1.8

Appendix 9 - Ongoing efficiency

1.1. Chapter 6 presented the initial results of our analysis of productivity and unit cost trends from the EU KLEMS database. This appendix provides further details on the methodology we used and results for all sectors in the database.

Approach

1.2. The methodology that we have used builds on the approach developed by Ofgem's consultants - Reckon LLP - at the gas distribution price control. Their report calculated labour productivity growth adjusted for the effect of capital substitution[7]. Reckon have updated this approach in a study for Ofwat where they calculated growth in labour unit costs and growth in a measure of operating expenditure per unit of output using the EU KLEMS dataset[8]. Ofwat will use this report as part of the evidence that will inform the efficiency assumptions made in its draft and final determinations in July and November this year.

1.3. This appendix provides an outline of the methods we have followed to generate the figures presented in chapter 6. Further details can be found in the Reckon reports referenced above.

Method

Calculating productivity trends

1.4. The Reckon reports demonstrate how productivity trends at constant capital can be calculated using the standard definitions of the growth in total factor productivity (TFP). These definitions can be found in the EU KLEMS overview paper which provides a description of the methodology that they used[9].

1.5. The formulae below provide these standard formulae for TFP growth calculated on a value added (VA) and gross output (GO) basis.

[7] Reckon (2007) "Gas distribution price control review: Update of analysis of productivity improvement trends" (www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/Reckon%2027Sep2007%20Report.pdf)
[8] Reckon (2008) "PR09 Scope for efficiency studies" (www.ofwat.gov.uk/publications/commissioned/rpt_com_scopeefficiencyreckon.pdf)
[9] Marcel Timmer, Mary O'Mahony and Bart van Ark, The EU KLEMS Growth and Productivity Accounts: An Overview, University of Groningen & University of Birmingham, March 2007 (http://www.euklems.net/data/overview_07ii.pdf)

Growth in TFP (VA) =	*Growth in the volume of VA*
	*-(share of capital in VA * growth in the volume of capital)*
	*-(share of labour in VA * growth in the volume of labour)*
Growth in TFP (GO) =	*Growth in the volume of GO*
	*-(share of capital in GO * growth in the volume of capital)*
	*-(share of labour and intermediate inputs in GO * growth in the volume of labour and intermediate inputs)*

1.6. To calculate productivity trends assuming constant capital we set the growth of capital equal to the growth in the relevant output measure (VA or GO). This allows us to calculate productivity trends that are not attributable to changes in capital intensity. The formulae below show how the relevant productivity measures can be calculated once this assumption has been made and the formulae have been rearranged.

$$\textit{Growth in labour productivity (VA) at constant capital} = \frac{\textit{Growth in TFP (VA)}}{\textit{Share of labour in VA}}$$

$$\textit{Growth in labour and intermediate input productivity (GO) at constant capital} = \frac{\textit{Growth in TFP (GO)}}{\textit{Share of labour and intermediate inputs in GO}}$$

1.7. These formulae were used to calculate the productivity trends presented in chapter 6. The section below discusses how these productivity trends were used to calculate the unit cost trends that were also presented in chapter 6.

Calculating unit cost trends

1.8. Unit cost trends can be calculated by combining a productivity trends with a relevant input price trends. The formulae below set out how we converted the productivity growth trends discussed above into unit cost trends.

Growth in unit labour costs (VA) at constant capital (relative to the RPI)	=	*Growth in wages* *- Growth in RPI* *- Growth in labour productivity (VA) at constant capital*
Growth in unit labour and intermediate input costs (GO) at constant capital (relative to the RPI)	=	*Growth in wages and price of intermediate inputs* *- Growth in RPI* *- Growth in labour and intermediate input productivity (GO) at constant capital*

1.9. The input price trends used to calculate growth in these unit costs were the relevant trends in each of the EU KLEMS sectors. For example, unit labour costs in the chemicals sector was calculated by combining the productivity trend in this sector with the wage trend in the sector.

Results for all sectors in the EU KLEMS dataset

1.88. Chapter 6 only presented the results of our preliminary analysis for a subset of the sectors in the database. We present below the results for all the sectors in the "basic" EU KLEMS where sufficient data existed. We also present the EU KLEMS code for each sector.

Table 1 - Compound annual growth rates for productivity and unit costs adjusted for constant capital (1970-2005)

Comparator sector	EU KLEMS sector code	Gross output measures		Value added measures	
		Labour and intermediate inputs productivity growth	Unit labour and intermediate inputs costs (relative to the RPI)	Labour productivity growth	Unit labour costs (relative to the RPI)
Agriculture, hunting, forestry and fishing	AtB	1.1%	(1.7%)	3.6%	(1.3%)
Mining and quarrying	C	(2.3%)	6.0%	(6.8%)	11.9%
Total manufacturing	D	0.6%	(0.4%)	2.1%	(0.2%)
Manufacture of food, beverages and tobacco	15t16	0.1%	(0.8%)	0.6%	0.4%
Manufacture of textiles, textile products, leather and footwear	17t19	0.8%	(1.1%)	2.2%	(0.6%)
Manufacture of wood, wood and cork products	20	0.2%	(0.3%)	0.8%	0.9%
Manufacture of pulp, paper and paper products; publishing and printing	21t22	0.4%	0.2%	1.0%	1.2%
Manufacture of chemical, rubber, plastic and fuel products	23t25	0.8%	(0.1%)	3.9%	(1.1%)
Manufacture of coke, refined petroleum products and nuclear fuel	23	(0.1%)	1.3%	(1.2%)	3.1%
Manufacture of chemicals, chemical products and man-made fibres	24	1.4%	(1.5%)	5.6%	(2.6%)
Manufacture of rubber and plastic products	25	0.9%	(0.7%)	2.7%	0.2%
Manufacture of other non-metallic mineral products	26	0.9%	0.3%	2.4%	0.5%
Manufacture of basic metals and fabricated metal products	27t28	0.7%	(0.1%)	2.3%	0.1%
Manufacture of machinery not elsewhere classified	29	0.4%	(0.0%)	1.0%	0.2%
Manufacture of electrical and optical equipment	30t33	1.6%	(2.0%)	5.0%	(2.7%)
Manufacture of transport equipment	34t35	1.0%	(0.6%)	3.2%	(1.7%)
Manufacturing not elsewhere classified; recycling	36t37	(0.8%)	0.9%	(2.8%)	5.3%
Electricity, gas and water supply	E	1.3%	(1.8%)	6.6%	(3.9%)
Construction	F	0.3%	1.3%	0.8%	1.6%
Wholesale and retail trade	G	(0.0%)	1.0%	0.2%	1.5%
Sale, maintenance and repair of motor vehicles and motorcycles; retail sale of fuel	50	0.7%	0.6%	1.5%	1.1%
Wholesale trade and commission trade, except of motor vehicles and motorcycles	51	(0.5%)	1.2%	(1.0%)	2.6%
Retail trade, except of motor vehicles and motorcycles; repair of household goods	52	0.3%	0.8%	0.6%	0.8%

		Gross output measures		Value added measures	
Comparator sector	**EU KLEMS sector code**	**Labour and intermediate inputs productivity growth**	**Unit labour and intermediate inputs costs (relative to the RPI)**	**Labour productivity growth**	**Unit labour costs (relative to the RPI)**
Hotels and restaurants	H	(0.5%)	2.7%	(2.3%)	7.0%
Transport and storage and communication	I	1.5%	(0.7%)	3.1%	(0.7%)
Transport and storage	60t63	1.2%	(0.5%)	2.6%	(0.3%)
Post and telecommunications	64	2.4%	(1.5%)	4.6%	(2.1%)
Finance, insurance, real estate and business services	JtK	(0.8%)	1.7%	(1.9%)	3.4%
Financial intermediation	J	(0.5%)	1.3%	(1.1%)	2.5%
Real estate, renting and business activities	K	(0.9%)	1.9%	(2.1%)	3.6%
Real estate activities	70	(2.3%)	3.0%	(12.3%)	14.1%
Renting of machinery and equipment, and other business activities	71t74	(0.3%)	1.4%	(0.7%)	2.3%
Community, social and personal services	LtQ	(0.5%)	1.4%	(0.9%)	2.1%
Public administration and defence; compulsory social security	L	(0.5%)	1.5%	(0.9%)	2.3%
Education	M	(1.0%)	1.2%	(1.6%)	1.9%
Health and social work	N	0.1%	1.4%	0.2%	1.4%
Other community, social and personal services	O	(0.5%)	1.4%	(1.4%)	2.7%

Appendix 10 - Customers

1.1. This section sets out the methodology we propose to use to derive the CI and CML benchmarks, how we propose to set the CI and CML targets for DPCR5 and the associated incentive rates and bandwidths around the targets.

CI Benchmarking methodology

HV

1.2. We are continuing to use the most recent three years' data and will extend this to four years once we have all of the 2008-09 data.

1.3. We are using the L0 band definition of 100.1 metres as set out in paragraph 1.55 of appendix 7 to the December paper.

1.4. We are taking into account customer density on each feeder.

1.5. We are using the following weightings on fault rates in the benchmarking:

- Underground bands (UG) - 80 per cent own; 20 per cent industry
- Mixed bands (MA) - 60 per cent own; 40 per cent industry
- Mixed bands (MB) - 40 per cent own; 60 per cent industry
- Mixed bands (MC) - 20 per cent own; 80 per cent industry
- Overhead bands (OH) - 0 per cent own; 100 per cent industry

LV

1.6. We are comparing LV performance at the total level and will be looking to refine the reporting of LV interruptions data in DPCR5 in order to capture more accurately and consistently this information. We will be working with industry to modify the relevant regulatory instructions and guidance and will consult on the proposed amendments.

EHV/132kV

1.7. We are using data from 2002-03 onwards adjusted for customer numbers for the respective years to set the EHV and 132kV benchmarks.

CI target setting

1.8. Where a DNO's own current average performance or their base case performance is less than or equal to the 2014-15 benchmark then we propose to take the lower of these values to set their target. This applies to six DNOs as set out in table 1 below. For these six DNOs their targets for DPCR5 are the lower of their base case or current average performance – there is no effective glidepath nor startpoint.

Table 1 - Using the lower of DNO base case or DPCR4 average performance to set 2014-15 targets

DNO	DNO base case	DPCR4 average	2014-15 benchmark	2014-15 target
ENW	49.4	50.8	50.8	49.4
WPD S West	71.9	73.9	73.7	71.9
EDFE LPN	34.0	33.0	33.0	33.0
SP Distribution	58.7	59.3	58.7	58.7
SP Manweb	41.7	42.3	42.3	41.7
SSE Hydro	69.8	68.3	68.3	68.3

1.9. Where this is not the case we have sought to dampen the impact of volatility in fault rates by taking a longer run average for fault rates. We have then combined this with the more recent customers per fault information, given that this is one of the metrics that DNOs will have targeted to improve during DPCR4. These revised averages have then been compared with the 2014-15 benchmarks. Where the revised average is less than the 2014-15 benchmark we have concluded that the 2014-15 benchmark is attainable. This is the case for two DNOs as set in table 2 below. For these DNOs their current average performance sets the startpoint.

Table 2 - Taking account of revised DPCR4 average in setting 2014-15 targets

DNO	DNO base case	Revised DPCR4 average	2014-15 benchmark	2014-15 target
CE NEDL	63.8	62.8	63.6	63.6
EDFE EPN	72.7	68.2	70.1	70.1

1.10. For the remaining DNOs we have looked at the smallest gap between either their current or revised averages and the 2014-15 benchmark and, where the gap is less than the half a per cent per annum improvement factor included in the December benchmarking methodology then the 2014-15 benchmark becomes the 2014-15 target. Where the gap exceeds the annual improvement factor we have limited the required improvement to the half per cent per annum level. This is set out in table 3 below.

Table 3 - Taking account of gap closure in setting 2014-15 targets

DNO	DPCR4 average	Revised DPCR4 average	2014-15 benchmark	Smallest gap as a % of benchmark	2014-15 target
CN West	111.2	105.0	103.1	1.9%	103.1
CN East	75.6	75.3	70.6	6.6%	73.0
CE YEDL	73.5	68.0	67.1	1.4%	67.1
WPD S Wales	77.8	79.4	73.0	6.5%	75.4
EDFE SPN	82.9	81.6	77.6	5.1%	79.0
SSE Southern	71.1	74.3	70.5	0.9%	70.5

1.11. For these six DNOs we have taken the lower of DPCR4 average or revised DPCR4 average performance for the startpoint. Where the targets tighten over DPCR5 we have applied the same format for calculating the glidepath as was set out in the December paper i.e. the gap divided by five.

CML Benchmarking and target setting methodology

Table 4 - How the December unplanned CML 2014-15 targets were chosen

DNO	DPCR4 average	2009-10 target	2014-15 benchmark	December paper 2014-15 target
CN West	89.7	80.4	79.7	79.7
CN East	65.5	61.4	57.3	57.3
ENW	48.7	51.2	47.7	47.7
CE NEDL	58.2	59.8	55.4	55.4
CE YEDL	68.0	57.6	60.6	57.6
WPD S Wales	39.9	61.0	57.9	39.9
WPD S West	43.2	55.4	59.5	43.2
EDFE LPN	39.1	43.4	38.5	38.5
EDFE SPN	83.8	60.9	58.3	58.3
EDFE EPN	62.4	65.3	55.0	55.0
SP Distribution	66.1	47.1	50.6	47.1
SP Manweb	53.9	51.1	49.8	49.8
SSE Hydro	58.6	82.1	74.8	58.6
SSE Southern	64.8	69.6	58.4	58.4

Table 5 - How the May unplanned CML 2014-15 targets have been chosen

DNO	DNO 2014-15 base case	DPCR4 average	2014-15 benchmark	2014-15 target
CN West	89.7	89.7	79.7	79.7
CN East	65.5	65.5	58.9	58.9
ENW	48.2	48.7	47.7	47.7
CE NEDL	58.4	58.2	55.4	55.4
CE YEDL	68.9	68.0	60.6	60.6
WPD S Wales	40.6	39.9	59.6	39.9
WPD S West	42.7	43.2	58.2	42.7
EDFE LPN	39.6	39.1	38.5	38.5
EDFE SPN	87.1	83.8	59.1	59.1
EDFE EPN	62.6	62.4	55.0	55.0
SP Distribution	54.4	66.1	50.6	50.6
SP Manweb	53.7	53.9	49.7	49.7
SSE Hydro	59.3	58.6	74.8	58.6
SSE Southern	64.8	64.8	58.4	58.4

Table 6 - How the startpoints have been calculated

	December		May	
DNO	DPCR4 average	2009-10 target	DPCR4 average	DNO 2009-10 base case
CN West	89.7	80.4	89.7	89.7
CN East	65.5	61.4	65.5	65.5
ENW	48.7	51.2	48.7	48.1
CE NEDL	58.2	59.8	58.2	59.3
CE YEDL	68.0	57.6	68.0	68.5
WPD S Wales	39.9	61.0	39.9	40.6
WPD S West	43.2	55.4	43.2	42.7
EDFE LPN	39.1	43.4	39.1	39.1
EDFE SPN	83.8	60.9	83.8	86.6
EDFE EPN	62.4	65.3	62.4	62.1
SP Distribution	66.1	47.1	66.1	54.2
SP Manweb	53.9	51.1	53.9	53.9
SSE Hydro	58.6	82.1	58.6	59.3
SSE Southern	64.8	69.6	64.8	64.8

Table 7 - CI incentive rates per customer

DNO	2007-08 incentive rate per customer in 2007-08 prices	WTP incentive rate per customer	Difference	50% of difference	DPCR5 incentive rate per customer
CN West	£ 5.98	£ 4.02	-£ 1.96	-£ 0.98	£ 5.00
CN East	£ 7.85	£ 4.02	-£ 3.83	-£ 1.91	£ 5.93
ENW	£ 10.68	£ 4.02	-£ 6.66	-£ 3.33	£ 7.35
CE NEDL	£ 8.53	£ 4.02	-£ 4.51	-£ 2.25	£ 6.27
CE YEDL	£ 8.42	£ 4.02	-£ 4.40	-£ 2.20	£ 6.22
WPD S Wales	£ 8.88	£ 4.02	-£ 4.86	-£ 2.43	£ 6.45
WPD S West	£ 8.90	£ 4.02	-£ 4.88	-£ 2.44	£ 6.46
EDFE LPN	£ 18.06	£ 13.46	-£ 4.60	-£ 2.30	£ 15.76
EDFE SPN	£ 5.65	£ 4.02	-£ 1.63	-£ 0.81	£ 4.83
EDFE EPN	£ 6.14	£ 4.02	-£ 2.12	-£ 1.06	£ 5.08
SP Distribution	£ 15.56	£ 4.02	-£ 11.54	-£ 5.77	£ 9.79
SP Manweb	£ 16.00	£ 4.02	-£ 11.98	-£ 5.99	£ 10.01
SSE Hydro	£ 15.94	£ 4.02	-£ 11.92	-£ 5.96	£ 9.98
SSE Southern	£ 8.46	£ 4.02	-£ 4.44	-£ 2.22	£ 6.24

Table 8 - CML incentive rate per customer

DNO	2007-08 incentive rate per customer in 2007-08 prices	WTP incentive rate per customer	Difference	50% of difference	DPCR5 incentive rate per customer
CN West	£ 0.08	£ 0.07	-£ 0.01	-£ 0.01	£ 0.08
CN East	£ 0.10	£ 0.07	-£ 0.03	-£ 0.02	£ 0.09
ENW	£ 0.14	£ 0.16	£ 0.02	£ 0.01	£ 0.15
CE NEDL	£ 0.11	£ 0.07	-£ 0.04	-£ 0.02	£ 0.09
CE YEDL	£ 0.11	£ 0.07	-£ 0.04	-£ 0.02	£ 0.09
WPD S Wales	£ 0.15	£ 0.07	-£ 0.08	-£ 0.04	£ 0.11
WPD S West	£ 0.15	£ 0.07	-£ 0.08	-£ 0.04	£ 0.11
EDFE LPN	£ 0.20	£ 0.06	-£ 0.14	-£ 0.07	£ 0.13
EDFE SPN	£ 0.08	£ 0.07	-£ 0.01	-£ 0.01	£ 0.08
EDFE EPN	£ 0.09	£ 0.07	-£ 0.02	-£ 0.01	£ 0.08
SP Distribution	£ 0.21	£ 0.07	-£ 0.14	-£ 0.07	£ 0.14
SP Manweb	£ 0.19	£ 0.04	-£ 0.15	-£ 0.08	£ 0.12
SSE Hydro	£ 0.20	£ 0.12	-£ 0.08	-£ 0.04	£ 0.16
SSE Southern	£ 0.12	£ 0.07	-£ 0.05	-£ 0.02	£ 0.09

Table 9 - Upper and lower bounds around the 2009-10 and 2014-15 CI targets

	2009-10		2014-15	
DNO	**Upper bound**	**Lower bound**	**Upper bound**	**Lower bound**
CN West	125	75	130	76
CN East	93	56	95	51
ENW	71	42	67	32
CE NEDL	89	53	85	42
CE YEDL	83	50	87	47
WPD S Wales	107	64	104	47
WPD S West	101	60	97	47
EDFE LPN	44	27	42	24
EDFE SPN	102	61	100	58
EDFE EPN	104	62	93	48
SP Distribution	74	45	79	38
SP Manweb	57	34	58	26
SSE Hydro	111	67	101	36
SSE Southern	106	64	96	45

Table 10 - Upper and lower bounds around the 2009-10 and 2014-15 CML targets

	2009-10		2014-15	
DNO	**Upper bound**	**Lower bound**	**Upper bound**	**Lower bound**
CN West	105	56	106	53
CN East	80	43	81	37
ENW	67	36	61	35
CE NEDL	78	42	77	33
CE YEDL	75	40	81	40
WPD S Wales	79	43	65	15
WPD S West	72	39	64	21
EDFE LPN	56	30	54	23
EDFE SPN	79	43	79	39
EDFE EPN	85	46	76	34
SP Distribution	61	33	73	29
SP Manweb	66	36	70	29
SSE Hydro	107	57	89	28
SSE Southern	90	49	84	33

Appendix 11 - Network outputs

Further details of network output measures proposed by the DNOs

1.1. Table 1 below summarises the outputs each DNO has proposed for General Reinforcement (EHV and 132 kV) and Asset Replacement.

Table 1 - Summary of DNOs proposed outputs - General Reinforcement (EHV and 132 kV) and Asset Replacement

DNO	Proposed Output General Reinforcement (EHV and 132 kV)	Proposed Output Asset replacement (all voltages)
CN	Reduction in the number of substations loaded at greater than 110%. Reduction in the number of substations where the ratio of MVAh (above firm)/MVA (firm) is greater than 2.5	Asset Health Indices Asset Fault Rates
ENW	Count of overloaded nodes	Asset Health Indices Asset Fault Rates
CE	Composite Risk Indices (CRI) proposed for primaries (based on % over firm, time over firm, historical load growth, number of customers, transfer capacity) Number of P2/6 Non compliances	Health Indices Service life Extension (SLE) - high level metric comparing cumulative planed expenditure and output of a age based model) Faults rates (as a general indicator)
WPD	Number of primary substations at each utilisation level (loading as % of firm) in 10% bands.	Asset Health Indices Asset Fault Rates
EDFE	Nominal 132kV and EHV intact system utilisation factor: i.e. SMD / aggregate transformer capacity (based on cyclic rating) at each voltage level	Primary Distribution Asset and Secondary Distribution Asset Health Indicator (composite health indices normalised based on unit cost)
SP	Composite Index for primaries (based on % over firm, time over firm, historic load growth, number of customers) Number of ER P2/6 Security of Supply non-compliances – addressed.	Asset Health Indices Asset Fault Rates
SSE	Count of trips resulting from overloading of a primary substation.	Asset Health Indices Asset Fault Rates

Other areas of Investment

1.2. A number of the other areas of investment are covered by existing outputs or incentives (or proposed incentives). Areas of investment not covered are:

- LR3 - Diversions,
- LR4 - LV and HV general reinforcement,
- LR6 - Fault Level,
- NL7 - Major Sys Risks,
- NL8 - Operational IT and telecoms, and
- NL9 - Legal and Safety.

1.3. Table 2 below highlights the range of outputs proposed by the DNOs for these areas of investment. In a number of cases the outputs proposed are tier three e.g. number of flood defences installed.

1.4. At present we are primarily focussing on output measures to capture what the DNO achieves through asset replacement expenditure and expenditure on general reinforcement. These categories of expenditure account for 78 per cent of forecast core network investment in DPCR5.

1.5. We will consider the outputs proposed by the DNOs in assessing their appropriate levels of network investment but at this stage we are not proposing to introduce formal output measures relating to the other areas of investment. For these other areas of investment Ofgem intends that outputs should be further developed during DPCR5 to enable benchmarking between DNOs where possible and if required for future settlements.

Table 2 - Summary sample of DNOs proposed outputs - Other areas of Investment

Building Block	Suggested Outputs
LR1 – Demand Connections	Number of New Connections Level of spare capacity provided by upstream reinforcement Change in net demand
LR3 - Diversions	Volume of requests to move equipment Volume of negotiated settlements Lengths of Diversion by voltage
LR4 – LV and HV	Limit on number of distribution transformers where demand is greater than 125% of cyclic rating Number of voltage complaints resolved Number of circuits up-rated Count of number of overloaded nodes Customers/demand/time at risk due to an unplanned outage
LR6 – Fault level	Number of switchboards replaced due to fault levels
NL7 - Major Sys Risks	Increased security for high GVA areas Number of sites with improved flood defence Estimated reduction in the proportion of customers at risk of flooding.
NL8 - Operatnl IT & Telecoms	Removal of all BT21CN affected circuits by Number of RTUs replaced Extension of distribution remote control
NL9 - Legal & Safety	ESQCR proximity - Volumes of non-compliances resolved Volume of information distributed to publicise electrical hazards Asbestos removal - Removal of poor condition asbestos from primary substations
NL10 - Environmental	Oil pollution - Length of fluid-filled cables with fluid leak mitigation work completed Noise complaints addressed within timescales Transformer Bunding - Number of sites where mitigation works have been undertaken Volume of OHL in AONBs and National Parks that is undergrounded

Further details of Ofgem's proposed output measures

EHV and 132 kV General reinforcement Load Index (LI)

1.6. Ofgem's proposed methodology is for all DNOs to assign a Load Index to each EHV and 132 kV substation. The Load Index (LI) will be similar to the more conventional Health Index (HI) but instead of condition the Load Index will reflect the requirement for reinforcement based on the three key drivers of substation reinforcement:

- current demand as percentage of firm (n-1) capacity,
- current duration over firm or the integral of time over firm and MVA over firm, and
- forecast load growth.

1.7. The LI will indicate both the likely timeframe in which a substation will require reinforcement and the relative loading risk on each substation. An example of this is shown in table 3 below. The exact scale and banding will be developed with the DNOs over the coming months.

Table 3 - Example of LI definitions

Load Index (LI)	Time frame for reinforcement	Level of relative risk
LI 1	Not foreseeable	Very low
LI 2	>10 years	Low
LI 3	5 – 10 years	Medium
LI 4	3 - 5 years	High
LI 5	<2 years	Very High

1.8. The data for all three drivers is readily available as DNOs have highlighted these as being the key factors used in assessing the reinforcement requirements of their networks. In addition similar data is already collected as part of the existing RRP load related risk tables or is published by the DNOs in their Long Term Development Statement (LTDS)[10].

1.9. The need to reinforce a substation will be driven both by the absolute level of each individual driver and the interdependency of the factors. Therefore in order to assign a LI a logic table is required to take the different combination of the drivers and equate them in a consistent way to form a LI.

[10] LTDS - Information published by the DNOs including detailed network information and development proposals to help anyone potentially connecting load or generation to identify opportunities and constraints on the network.

1.10. Table 4 below contains an <u>example</u> of a logic table to show how logic tests could be structured to assign LI bands one and two. This would need to be repeated for all five LI bands.

Table 4 - Example of LI logic table

Load Index	Driver	Logic		
LI 1	Demand/Firm Capacity (%)	<100%	OR	100% -105%
	Average forecast Growth (% p.a.)	time to over firm is > 5years		<0%
	Duration over Firm (hr/year)	N/A		10 hours
LI 2	Demand/Firm Capacity (%)	<100%	OR	100% -105%
	Average forecast Growth (% p.a.)	time to over firm is < 5years		<0%
	Duration over Firm (hr/year)	N/A		10 hours

1.11. The exact format and the structure of the logic table will need to be developed with the DNOs over the coming months. The starting assumption will be that the same logic table could be applied to all DNOs or at least form the basis of a starting point for development. There may be valid reasons for modifying the table for individual DNOs based on:

- different levels of manual transfer between substations,
- different network topologies,
- different approaches to network operation, and
- different trigger points for investment and approach to risk.

Asset replacement Health Index (HI)

1.12. All DNOs have proposed the use of HI for asset replacement. Although DNOs have implemented HI in different ways and are at different stages of maturity it is Ofgem's view that a common method of reporting and presenting HI is appropriate.

1.13. Like the proposed LI we propose to use a banding of 1-5 as shown in table 5 below.

Table 5 - Example of HI definitions

Health Index	Time frame for replacement	Level of relative risk
HI 1	Not foreseeable	Very low
HI 2	>10 years	Low
HI 3	5 – 10 years	Medium
HI 4	3 - 5 years	High
HLI 5	<2 years	Very High

1.14. DNOs would be required to map their existing internal HI to the common methodology. Where a DNO believes this is not appropriate the DNOs would need to provide an alternative approach.

1.15. Where a full set of condition data is not available the DNO may need to make assumptions about the condition of assets, such as an assumption regarding the relationship between age and condition. DNO will need to make this clear where this is the case.

Asset replacement fault rates and volumes

1.16. DNOs currently report asset fault rates in their Medium Term Performance (MTP) submissions. This reporting could be modified to provide the data requirements for output measure fault rate reporting. Ofgem will work with the DNOs to refine the current MTP reporting requirements.

1.17. In the short-term asset fault rates can show significant volatility between years. In order to give a more stable output measure fault rates can be considered over several years, for example taking a 5 year rolling average.

1.18. Fault rates for some assets (particularly overhead lines) can be altered greatly by exceptional events such as extreme adverse weather conditions. Fault rates could be reporting both including and excluding defined exceptional events.

1.19. In order to assess the effectiveness of refurbishment works fault rates for overhead lines can be split between those on refurbished lines and those on non-refurbished lines.

Reporting templates and graphical summary

1.20. Tables 6 and 7 below show an example of a common template for the DNOs to submit the outputs for general reinforcement and asset replacement.

Table 6 - General Reinforcement Reporting Template

LI	Number of Substations		
	Year 0	Year 5 (no intervention	Year 5 (with investment)
LI1			
LI2			
LI3			
LI4			
LI5			
	Percentage of Customers Supplied		
LI1			
LI2			
LI3			
LI4			
LI5			

Table 7 - Asset replacement HI

	Year 0					Year 5 (no intervention)					Year 5 (with investment)				
Asset Cat	HI 1	HI 2	HI 3	HI 4	HI 5	HI 1	HI 2	HI 3	HI 4	HI 5	HI 1	HI 2	HI 3	HI 4	HI 5
Asset 1															
Asset 2															
Asset 3															
Asset 4															
Asset 5															

1.21. Figures 1 and 2 below show an example of how the LI and HI profiles could be presented graphically to provide a high level summary.

Figure 1 - General Reinforcement graphical summary of LI profile

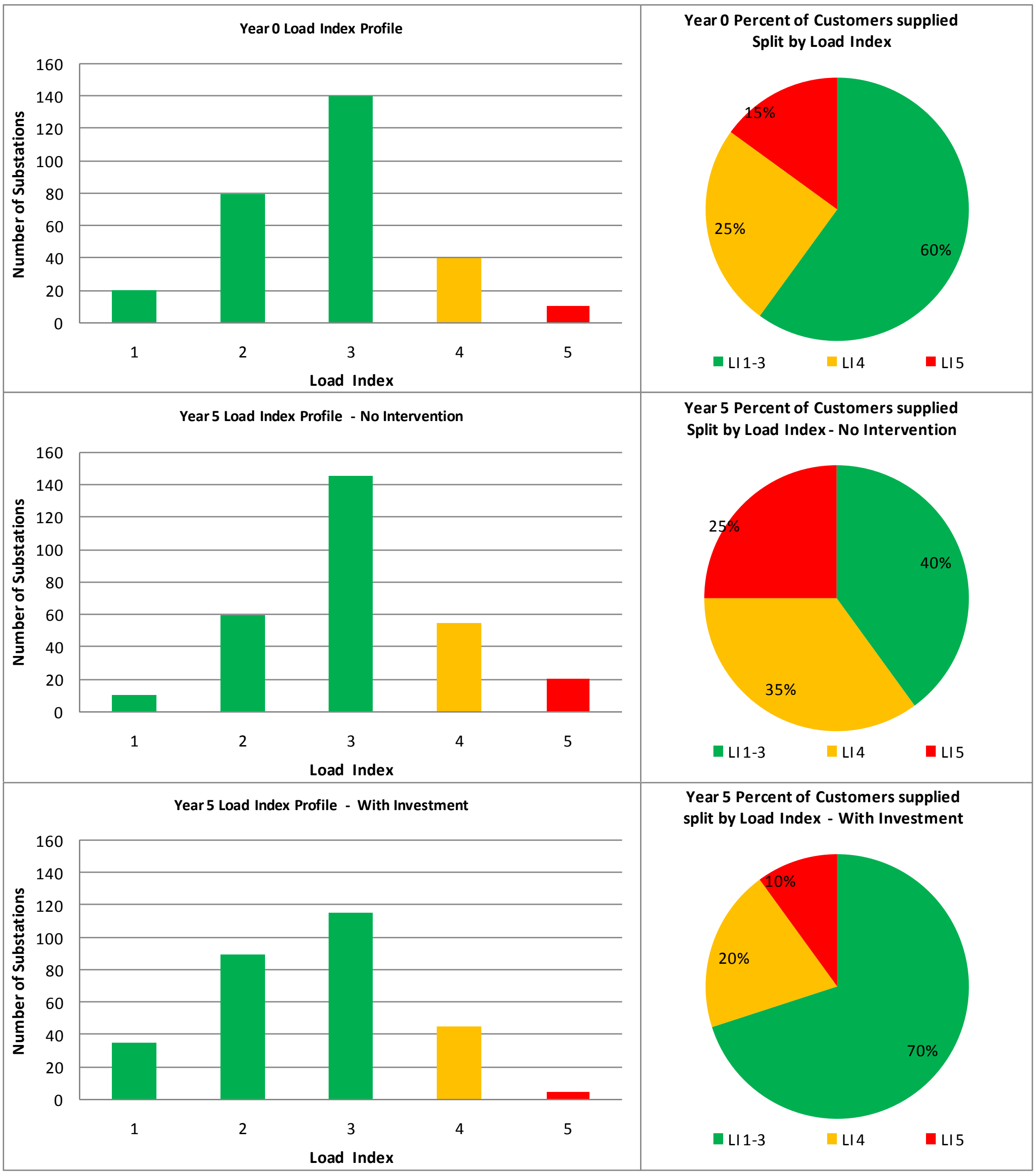
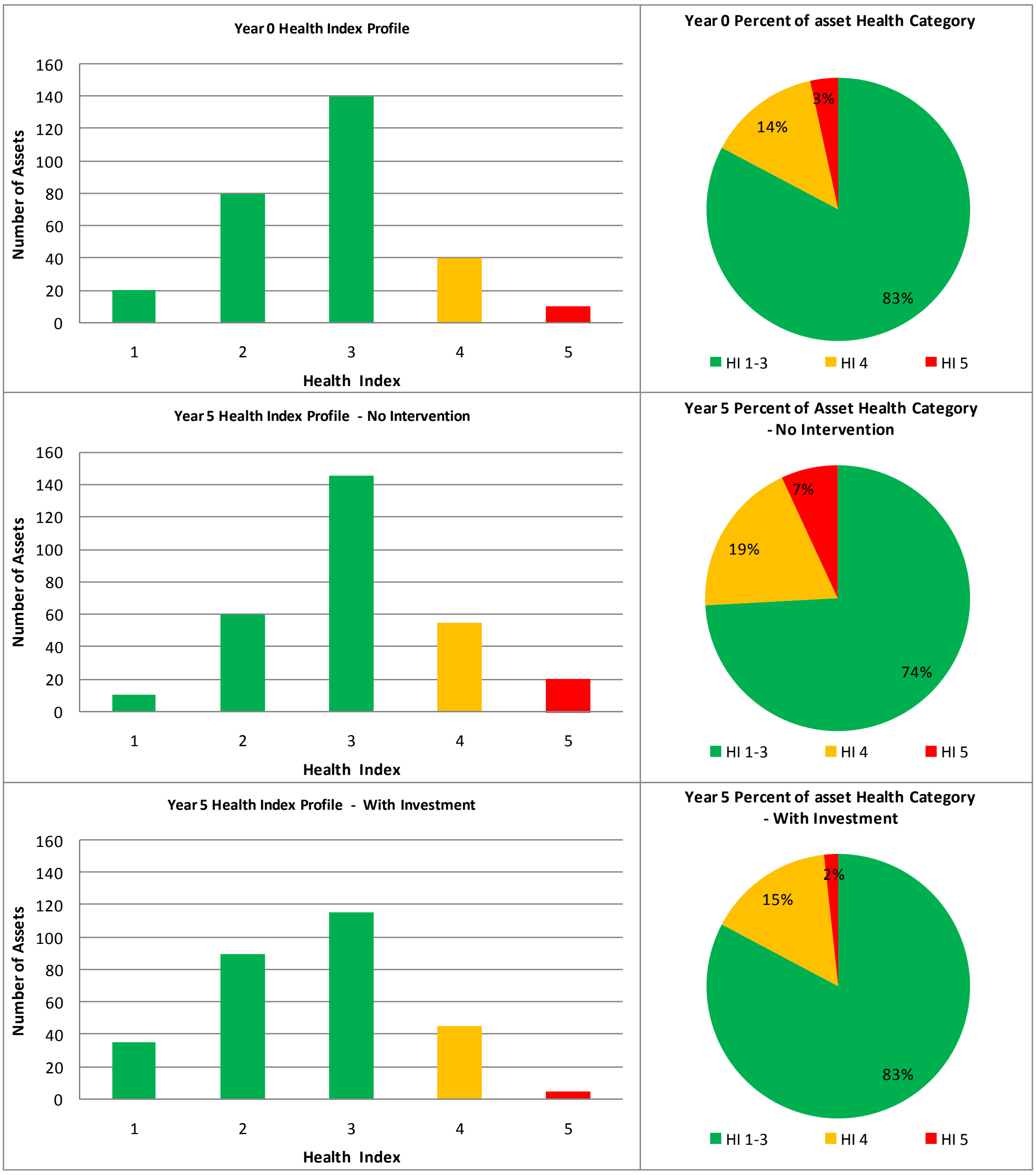


Figure 2 - Asset Replacement graphical summary of HI profile



Appendix 12 - RAV application issues

Chapter summary

Our overall approach to computing RAV additions is explained in chapter 9. This appendix sets out the background to our approach and deals with some detailed application issues.

Question 1: Views are invited on the approach to RAV additions and the range of costs to be capitalised.
Question 2: Views are invited on which approach to these costs is equitable over the long term as between DNOs and consumers and should be adopted?

RAV Methodology

Background

1.1. In DPCR4, RAV additions were computed as 100 per cent of capex, 23.5 per cent of direct opex, 52.57 per cent of indirect opex and 57.7 per cent of total pension costs (excluding pension administration costs paid directly by the DNO that are included in indirect opex). In practice, the methodology created boundaries that were difficult to monitor and resulted in costs not being reported consistently across DNOs.

1.2. In developing the methodology for setting RAV additions our objectives have been to:

- ensure that economic trade-offs are not distorted between opex and capex solutions,
- address the boundary issues for cost reporting,
- remove mismatching in the treatment of total connection costs and contributions,
- reducing the perverse incentive to out-source rather than in-source because of the different RAV treatment of direct and indirect costs,
- ensure that DNOs are not discouraged from applying non-network solutions which are compatible with tackling climate change, such as contracting with DG and DSM,

- review the apparent disincentive to provide relevant excluded service costs which currently penalises DNOs for providing additional levels of services above their price control forecast and options for recognising a return (profit), and

- resolve the treatment of captive insurance costs and margins.

Options for computing RAV additions

1.3. To address this we had considered two potential options for computing RAV additions. To apply a fixed percentage to total costs (totex) of the distribution business using the four building blocks or exclude business support costs. The building blocks are (i) Network Investment, (ii) Direct Opex (including non-op capex) costs, (iii) Engineering Indirect costs and (iv) Business Support costs. For the reasons explained in the costs incentives chapter, our preference is for the second option. This has merit in that it resolves the majority of boundary issues and allows the retention of a strong incentive rate for business support costs to be managed efficiently.

1.4. In determining the range for allowing totex to RAV, we have reviewed:

- the DNOs' own accounting policy treatment (as shown in the annual RRPs) which range from 58 to 76 per cent with an average of 65 per cent,

- how they recorded these costs in their tax returns for computing capital allowances, which ranges from 42 to 78 per cent with an average of 67 per cent, and

- the average additions from applying the DPCR4 rules, which range from 61 to 66 per cent with an average over the first three years of DPCR4 of 64 per cent.

1.5. The appropriateness of the percentage will also be considered in our review of financeability. However, on the assumption that sole use connections costs become an excluded service and are excluded from RAV, we consider that the capitalisation rate applying the DPCR4 RAV methodology on a totex basis is likely to be around 64 to 66 per cent. This range on the preferred basis of treating business support and pension deficit as 100 per cent opex is around 79 to 82 per cent. We have observed through the RRP and tax return data that up to 49 per cent of the Business Support building block may be capitalised by different DNOs. This option may, in our view, still leave some boundary issues and distortions to incentives relating to business support costs. However, we consider that these issues are outweighed by maintaining strong incentives to manage costs in this area.

1.6. At DPCR4, normal pension funding costs and pension administration costs (including the PPF Levy) entered RAV at 57.7 per cent. Dependent on our ongoing review of the treatment of pension costs, we are reviewing whether it is appropriate that normal ongoing pension service costs should follow the employment costs in each building block into RAV. Forecasts of future pension deficit repair payments are potentially so big in some DNOs that they may distort the financial profile. These arise from past decisions and fluctuations in market conditions, and are not connected with future investment activity. We are reviewing whether they should also flow into RAV, or be funded on a pay-as you-go basis and, if so, over what period. The final treatment will be determined as part of the review of pension costs.

1.7. We will determine the mechanism for implementing the ex post adjustment due for DPCR4 in DPCR5 at Initial Proposals.

1.8. In DPCR4, the treatment of pension administration costs (including the PPF Levy) depended on whether they were paid directly by the DNO or by the trustees (funded through a levy on normal contributions). In the former case they were reported as part of Human Resources costs and entered RAV at 52.57 per cent, and, in the latter case, as part of pension costs and entered RAV at 57.7 per cent and, as such, were subject to true up. This treatment is inconsistent and for DPCR5, we intend to treat these costs the same as ongoing pension service costs. In DPCR4, the amounts are small and the treatment matches the way the allowances were determined. As such, we do not propose to revise their treatment when finalising DPCR4 RAV additions.

1.9. Views are invited on whether there should be a separate treatment of normal pension costs and/or deficit repair pension costs and on how and if they should flow into RAV.

Other Issues affecting RAV

1.10. Other issues being addressed affecting RAV are the treatment of excluded service costs and related party margins of affiliated captive insurance entities. Our current thinking and options to mitigate the apparent disincentive to provide relevant excluded service cost, which currently penalises DNOs for providing additional levels of services above their price control forecast, are reviewed in appendix 17.

Captive insurance affiliates

1.11. At DPCR4, the treatment of related party margins arising from captive insurance affiliates (captives) has been an ongoing issue, which has not been closed out in the RRP guidance. This principally revolves around the rule in the Final Proposals that related party (RP) profit margins should be disallowed where the RP’s external turnover does not exceed the 75 per cent threshold and whether it is inappropriate to apply this to captives; and the need to look through the captive to identify only those elements applicable to the distribution business. It arises because of the long-term nature of captive insurers' business. Our understanding is that these are set up with the intention of matching premiums and claims on an efficient and economical basis over many years and price control periods and there are tax efficiencies.

1.12. In DPCR4, profit margins have been disallowed in accordance with the normal RAV computation rules and any losses resulting from an excess of claims over premiums in any given year have been allowed as additional costs. However, there have been issues with computing profits and losses, as it is not always easy to identify movements in IBNR and technical reserves. This is particularly so when a captive insures more than a distribution business and those that cover an entire regional grouping.

1.13. In completing their RRPs for annual cost reporting not all DNOs have the information to make the annual "profit/loss" calculation on a timely basis. This is required to adjust RP margins for calculating RAV additions, due to the timing of captive's annual accounts sign-off; and the issue of clearly identifying only the costs and reserve movements applicable to the distribution business.

1.14. In the Initial Consultation, we undertook to review the treatment. At DPCR4, the amounts have not been material at an individual DNO level. We consider that there are three options:

- do nothing and continue as in DPCR4 but amend the instructions to exclude reference to an ex post review, or
- collect additional information to review and consider an ex post adjustment to eliminate only super–profits, say dividend distributions, or
- more radically, exclude captives from the related party margin rule and treat as any third party because of their reputed relevance to delivering efficient costs.

1.15. To close out the issue for DPCR4 and for DPCR5, we propose that the most appropriate route given the statement in the RRP Instructions for an ex post adjustment is the first option. We have not undertaken any work to measure effectively whether they actually deliver efficient cost over the long term or are just a financing vehicle to spread risks in the short-term, that do not materially benefit consumers. Although the amounts are not material at an individual DNO level the second option maintains the general rule on the disallowance of RP margins rather than introduce an ex post adjustment which may be beset with computational issues. The third option assumes that there is a level of efficiency in the arrangements. Should either of the last two option be adopted then to protect consumers the risks and rewards should all be borne by DNOs and any losses from claims occurred in any year in excess of premiums would be disallowed.

1.16. Views are invited on which approach to these costs is equitable over the long term as between DNOs and consumers and should be adopted.

General RAV computation rules

1.17. We propose to retain our generally applied rules for allowing costs/activities as RAV additions subject to necessary revision for changes because of the DPCR5 settlement and any tidying up where necessary, with the objective of resolving any boundary issues. These rules are set out in appendix 1 to the DPCR4 Final Proposals and, subject to the proposed amendments as noted, it is intended to published draft in the Initial Proposals document.

RAV Calculation 2008-09 and 2009-10

1.18. In the Initial Proposals, RAV additions for 2008-09 and 2009-10 will be based on DNOs' forecasts. These additions will be revised following receipt of the final annual 2008-09 cost reporting pack and will be incorporated in Final Proposals. In the event actual 2009-10 RAV additions turn out to be materially different to the estimate used, we would alter the revenue in the 2015-20 price control.

Regulatory depreciation

1.19. The current policy for depreciating the RAV is to use asset lives of 20 years, with a smoothing over 15 years in equal instalments for the "catch-up" depreciation between the difference between the shorter life for post-Vesting assets once Vesting assets[11] are fully depreciated.

1.20. We have considered the responses to the Policy Paper and have noted concerns that changes to the proportion of expenditure allocated to the RAV or an extension to the regulatory asset lives at successive reviews would bring an increase in future uncertainty. Some respondents have suggested that changing the regulatory asset lives increases the level of regulatory risk and that were we to do this they should be compensated for by a higher cost of capital. Whilst we do not agree with them, we are minded to retain the current regulatory treatment. This view is subject to a review of any long-term financeability issues that may be caused by having regulatory asset lives markedly shorter than actual asset lives and we will confirm our view or propose an alternative at Initial Proposals. Any potential change would only be relatively minor. Scottish DNOs are potentially facing a large reduction in their depreciation allowance as Vesting assets become fully depreciated (the so-called depreciation "cliff-face") from 2009-10. The English & Welsh DNOs faced this cliff-face at previous reviews, which was resolved as noted above by accelerating depreciation to 20 years with a catch-up. We are minded to extend the same treatment to them.

[11] Vesting assets comprise all assets held by a business at Vesting (i.e. legal changeover for privatisation), value based on flotation values.

Appendix 13 – High impact low probability events

Introduction

1.1. In August 2007, a joint BERR/Ofgem discussion paper was presented to the Energy Emergencies Executive Committee 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 high impact, low probability (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.

1.2. As a result of this paper, an Electricity Networks Association Working Group was established to give further consideration to this issue and recommend a way forward to the Energy Emergencies Executive Committee. The 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, in 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. It also suggested a hurdle rate that would justify proceeding with these investments.

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

Ofgem's approach

1.4. Ofgem has been actively involved in this work since the initial discussion paper to the Energy Emergencies Executive Committee. However, we have had concerns about providing a higher level of network security (i.e. higher than that required by the distribution licence) to a particular customer group and how this might be funded. Nevertheless, we made specific provision for DNOs to submit HILP proposals in their initial FBPQs and their final submissions in February of this year.

1.5. Further, in order to properly address our concerns about different treatment for 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 of network security being proposed. We are also continuing to discuss this issue with DECC.

FBPQ submissions

1.6. In the August 2008 initial FBPQ submissions, HILP investments were proposed in five of the fourteen licence areas totalling £98.7m. Although there have been minor modifications, these proposals have, with the exception of one company, been brought forward to the February submissions. They now total £63.9m, a reduction of 35 per cent compared with the previous submissions. The table below summarises the submissions. Scottish Power has also proposed HILP investments of £6.3m for specific parts of their networks that are not CBDs.

Table 1 - NL7 Submissions – Major System Risks - HILP

	August '08 FBPQ	February '09 CBD/Other*	CBD Change %
CN West	5.6	5.6/0.0	-
CN East	0.0	0.0	-
ENW	4.8	4.7/0.0	-2%
CE NEDL	4.0	0.0	Reduced to zero
CE YEDL	12.8	0.0	Reduced to zero
WPD S Wales	0.0	0.0	-
WPD S West	0.0	0.0	-
EDFE LPN	68.9	50.8/0.0	-26%
EDFE SPN	0.0	0.0	-
EDFE EPN	0.0	0.0	-
SP Distribution	1.0	1.1/3.7	+10%
SP Manweb	1.6	1.7/2.6	+6%
SSE Hydro	0.0	0.0	-
SSE Southern	0.0	0.0	-
All companies	**98.7**	**63.9/6.3**	**-35%**

* Non-CBD proposals

1.7. 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.

Next steps

1.8. Ofgem will continue to progress this issue both with the companies and government, taking into account stakeholders' views where possible. We are aware that there may be alternative ways to enhance network security other than those proposed to date. These should be explored.

1.9. We are committed to resolving this issue in a timescale that will allow us to include our assessment as part of our Initial Proposals baselines.

Appendix 14 - Taxation methodology statement

Approach

1.1. This appendix explains in detail our approach to taxation and the tax trigger mechanism.

Applicable tax regime

1.2. We will maintain our policy of applying the UK standard tax rules that have passed into legislation at the time of the Final Proposals.

1.3. All capital allowances will be assumed claimed at rates in line with applicable legislation; and claimed in the year the expenditure is incurred.

Tax losses

1.4. These have not been an issue for DNOs in the past and are not envisaged to be an issue in DPCR5. However, in line with our treatment in GDPCR, should tax losses arise we do not propose to give affected DNOs negative tax allowances, but we will log up any tax losses as calculated on a regulatory basis and deduct them from expected tax allowances when the timing differences that led to the loss reverse.

Modelling of capital allowances

1.5. For DPCR5, in order to mitigate the issue that in DNOs' view the DPCR4 methodology did not adequately replicate their tax liabilities to their detriment, we have considered three distinct options for the allocation of expenditure into the various capital allowance pools:

- The generic approach which involves using our view of how this allocation should be made,
- The common approach which relies on an 'average' actual allocation based on the information we receive from the DNOs moderated with our view of where capex should go according to the standard tax rules, and
- The specific approach, which uses the actual DNO-specific tax pool allocation policy.

1.6. We have reviewed our approach following discussions with DNOs and have collected additional data to enable us to evaluate moving closer to the DNOs' own allocations based on their own underlying expenditure profiles. We consider that the application of the capital allowance rules should in theory result in a consistent approach. In practice, we recognise that for historic reasons there are variations in treatment of similar items. This may arise in part from the differences in the FBPQ terminology and definitions compared to the DNOs own accounting for expenditure. Different approaches exist which, we understand have been agreed with HMRC over time and amending a previous and consistently applied and agreed treatment may be difficult. Applying a common approach has merit in that it aligns the tax treatment of all DNOs' cost categories (as defined in the FBPQ) and follows our consistent approach (in the financial model) of applying the same treatment to each element of costs making up the overall revenue allowance, e.g. WACC, debt, across licensees, pensions.

1.7. We are minded to revise our methodology to follow, where practical, the common treatment to attributions followed by DNOs moderated by our interpretation where there are significant discrepancies in treatment, for which we are still seeking explanations. Most DNOs were party to an agreement with HMRC, which in effect created a separate "deferred revenue" capital allowance pool for defined replacement and fault costs. However, two DNOs were not party to that agreement and they do not allocate any expenditure to this pool. By applying the common approach, we consider that this should result in the DPCR5 allocations being closer to the DNOs' own treatment but on an industry normalised basis.

1.8. We will use four main capital allowance pools – General, Long Life, IBA and Deferred Revenue and the relevant rates of annual writing down allowance. These reflect the relevant legislation in place at the DPCR5 review and take into account the legislative changes to the capital allowances regime since DPCR4. We will reflect the phasing out of IBAs. Some expenditure has been identified as non-qualifying (NQ) for capital allowances, principally easements being interests in land.

1.9. Where identified expenditure qualifying for either Research & Development Allowances or on environmentally beneficial technologies will be allowed at the enhanced rates. Following discussion with the DNOs, we have concluded that environmental remediation costs are not a factor in electricity distribution and no DNO is aware of any expenditure on this that would affect allowance setting.

1.10. All other expenditure not qualifying for capital allowances nor treated as non-qualifying will attract a 100 per cent deduction.

1.11. The annual allowance for deferred revenue will be 2 per cent straight-line, based on the average economic lives of all DNOs relevant assets at 51 years. At DPCR4, we assumed 2.5 per cent (40 years) straight line. We have observed DNOs have revised the economic lives of these assets and accept that it is appropriate to match this.

1.12. Based on our current analysis of data which is still under review and liable to change, we propose using the following attribution basis of the key building blocks to the capital allowances pools:

Table 1 – Cost allocation to capital allowance pools

	General pool	Longlife	IBA	Deferred Revenue	Revenue	Non-Qualifying
DNOs party to non-load agreement						
Load Related	0.5%	91.8%	2.9%	2.1%	0.0%	2.7%
Non-Load Related	4.7%	39.8%	3.5%	52.0%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	0.2%	0.0%	6.8%	93.0%	0.0%
Fault repairs and restoration	0.0%	0.0%	0.0%	65.0%	35.0%	0.0%
Tree cutting	0.0%	10.0%	0.0%	11.0%	79.0%	0.0%
Non Operational Capex	89.2%	2.0%	3.1%	0.1%	0.0%	5.5%
DNOs not party to non-load agreement						
Load Related	0.0%	98.3%	1.7%	0.0%	0.0%	0.0%
Non-Load Related	5.0%	88.9%	6.1%	0.0%	0.0%	0.0%
Other Network operating costs (inc I&M)	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Fault repairs and restoration	0.0%	77.5%	0.0%	0.0%	22.5%	0.0%
Tree cutting	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Non Operational Capex	78.1%	0.0%	0.0%	0.0%	0.0%	21.9%

Opening capital allowance pool balances

1.13. The opening capital allowance pool balances brought forward from DPCR4 have been calculated based on the licensees' own accounting policies / tax allocation rules. We had a concern since there have been substantial revisions to opening tax pools throughout the period from 2002-03 and there are usually several open tax years. As such, the pool balances reported in the RRP/FPBQ may not necessarily be a completely reliable indicator of the actual tax pools likely to be agreed with HMRC.

1.14. We are reviewing those balances against available evidence and evaluation of open issues with HMRC, where they exist, and subject to any adjustments we consider appropriate, will apply the balances reported in the FBPQ. We do not intend to adjust opening plant and machinery pools for the 2009 Budget announcement that there will be a one-year increase in first year allowances (from 20 per cent to 40 per cent) for qualifying assets purchased in 2009-10.

Capitalised indirect costs

1.15. In DPCR4, the RAV rules were applied as a proxy to attribute capitalised overheads. This treatment did not properly reflect DNOs' own treatment and hence their tax allowances. For DPCR5 we propose to apply individual DNOs capitalisation treatment of indirect costs and to these we will apply the attribution to capital allowance pools set out the table above. However, we are currently seeking further information to confirm the DNOs' own treatment of these costs follows the same treatment as the related capex.

Modelling the tax deductibility of pension cost

1.16. The tax treatment at DPCR4 was that all cash payments by the licensee into a pension scheme are 100 per cent deductible in the year incurred. Since then there has been a revision to the legislation such that large irregular payments will be spread over the current and up to three future years in accordance with the legislation, dependent on their magnitude[12]. We will also reflect this in computing the DPCR4 pension ex post adjustments.

1.17. For modelling and allowance setting, we will assume that all pension payments attributable to the distribution business (including that related to excluded services, but not necessarily distributed generation or metering) are paid in the year in which the allowance is given (to take account of the spreading of deficit repair costs).

1.18. In so far as, they are separately identifiable, pension deficit payments related to DG or metering will be taken into account.

Tax treatment of ex post adjustment of pension costs

1.19. The DPCR4 Final Proposals (FP) set out that, to the extent that pension contributions differ from pension allowances these would be offset against any future pension costs in determining future pension allowances. Any such adjustments would be net of tax, to the extent that the over or under payment has reduced or increased tax payable. In DPCR4, 57.7 per cent of actual pension contributions have been included in the RAV. That means that future revenues are affected by any over- or under-funding relative to the allowance. Any adjustments for over- or under-funding must not double-count this impact.

1.20. The ex post adjustment of the pension costs can be viewed in three parts:

a. the 57.7 per cent element treated as RAV additions in DPCR4 will be remunerated through future revenues in DPCR5 and beyond, as reflected in the future regulatory depreciation building block of the revenue calculation;

[12] The irregular payments rules to be applied are where payments in any one year which exceed 210% of that of the previous year will be spread over current and future years based on the magnitude of the increment. This applies as follows:

First 110%	110% of payment in current year (CY)
Excess (over 110% of prior year) is:	Tax relief obtained:
Less than £0.5m	All in CY
Between £0.5m and £1m	Half in CY and half in CY+1
Between £1m and £2m	One third each in CY, CY+1, CY+2
£2m or more	One quarter each in CY, CY+1, CY+2, CY+3

b. the amount reflected by regulatory depreciation in DPCR4 on the excess or shortfall added to, or subtracted from, RAV in DPCR4 at (a) ; and

c. the 42.3 per cent treated as opex.

All amounts will be net of any tax relief.

1.21. A draft simplified pension true-up model was circulated to DNOs after DPCR4 showing the general mechanics of computing the necessary adjustments set out above. This model assumed a constant 30 per cent rate of taxation and was prepared before the introduction of the irregular payment rules. As those rules do not affect any DNO in DPCR4 and spread tax relief into DPCR5, we propose to ignore these rules in calculating the true up. We will review whether the change in tax rate from 1 April 2008 to 28 per cent has any material influence on the adjustment.

Corporation Tax instalments

1.22. All DNOs are large companies under tax legislation and are required to pay their tax liabilities for any given year in instalments commencing in the current year. We will assume that the annual charge to CT is paid in quarterly instalments. This does not currently cater for DNOs' actual payments at the commencement of the period or for subventions, or additional payments (or receipts) from settling earlier years' tax liabilities.

1.23. It is proposed to ignore subventions for surrendered tax losses and to model CT payments as if they were settled as normal CT instalments of a single entity (ignoring ay group tax affects), i.e. part in the current year and part in the following year (50 per cent in each year).

1.24. Where appropriate we will use the forecast of the quarterly instalment payments due for the immediately preceding year that fall to be paid in DPCR5, these will be confirmed against the latest tax returns. It is not normal practice to take into consideration payments relating to settling open prior years. Likewise, we will not claw back the benefit of any refunds that are forecast to be received in DPCR5. We will assume that all liabilities modelled are paid in the appropriate period(s).

Interest (payable and receivable)

1.25. Interest receivable/payable will be modelled by applying the nominal rate of interest (of the debt element of WACC) to net debt (as defined in the tax clawback paper (see below). The amount will be on an accruals basis. Interest will be treated for tax purposes as fully deductible / taxable in the period in which it arises. The only exception to this will be in respect of the tax clawback (see below).

Tax treatment of incentives

1.26. In DPCR4, some incentives were pre and some post tax. For DPCR5, these will all be incentives on a consistent basis pre-tax basis. It also reflects the standard tax treatment of increases or decreases in actual revenues.

Treatment of IQI adjustments

1.27. In DPCR4, the incentive mechanism applies to RAV additions whether above or below the level of the allowance. As specifically set out in paragraph A1.23 of the DPCR4 Final Proposals the resultant revenues is intended to be on a pre-tax basis (i.e. it is not intended that they give rise to further revenues in respect of the tax charge in the revenues). Therefore, in the model, the adjustment will exclude any tax effects from changes to DPCR5 revenues, i.e. they are not being grossed up for computing the tax allowance.

Treatment of excluded services

1.28. Excluded service costs and revenues, including contestable sole use connections, are all assumed to match the way the price control is currently set and excluded services do not affect the setting of regulated base demand revenues. Accordingly, we propose to ignore these in assessing the tax allowance.

Tax Trigger

Background

1.29. As explained in chapter 11, we are proposing a symmetric sharing mechanism, subject to a trigger that activates once an explicit materiality threshold is reached to avoid adjusting for relatively small changes.

1.30. Our view is that any trigger would be restricted to specific legislative changes, i.e. to the rate of corporation tax applicable to large companies or to the rate(s) of tax relief for capital expenditure. These legislative changes must be both transparent and measurable by. Following consultation and further consideration, we acknowledge that there could be other legislative changes outside DNOs control (see below) that directly affect the tax burden that may need to be addressed.

1.31. In their responses, DNOs have suggested that the definition of legislative change should include:

- Any change in legislation that alters the cash tax charge for the DNO in the current price control period, and should specifically include changes in the relevant legislation whether introduced in a Finance Act, other Act of Parliament, Statutory Instrument or other legislative instrument,

- Changes in, or clarifications to, HMRC interpretation of legislation,
- New precedents set under case law, and
- Changes in accounting standards that have a knock-on effect on the quantum or timing of taxation.

1.32. The first point corresponds with our views on legislative changes and is measurable by us. We do not agree with the others as they may add unnecessary complexity and are likely either to fail the measurable test, or be quite specific and unlikely to meet the materiality threshold. However, we will review with DNOs under what conditions some of their other proposals can satisfy the transparent and measurable by us criteria. We do not consider that changes in accounting standards to be one where the risk and rewards should be passed to consumers, as it is not directly a change in tax legislation, neither is it measurable by ourselves. In addition, the adoption of reporting under IFRS is not mandatory and thus any impact of that decision is a discretionary choice of licensees or their ultimate controllers. For those licensees that have adopted IRFS we have yet to observe any material impact on the quantum or timing of their tax burden.

1.33. In our view, it is important to distinguish between legislative changes that affect the DNO on a stand-alone basis and those legislative changes that arise solely because of the DNO's membership of a group. We recognise that DNOs are generally part of a group, and do not seek to penalise them for being so. We regulate individual licensees as standalone entities and not groups; therefore, we propose to exclude legislative changes that affect DNOs solely because of their group structures, as this is something the ultimate controller of the group can influence.

1.34. An example of such exclusion would be the legislation proposed in the 2009 Budget on the "worldwide debt cap". This is aimed at restricting the deduction for tax relief of interest charges where a group has a lower interest charge (because it is has lower debt) than the UK entity. It is understood that the impact, in certain circumstances, has the potential to restrict the allowability of net external finance interest in the UK entity to that of the worldwide group. From discussions with DNOs, it is not currently possible for them to evaluate the potential impact or to quantify the effect on their tax burden until the full draft legislation is published; generally, few DNOs expect to be affected.

Proposed mechanism

1.35. The trigger mechanism is to be symmetrical and measurable and will be calculated by re-running the DPCR5 financial model to assess the impact on the tax allowance component of revenues on the basis of the average annual effect over the remainder of the price control period of:

- changes in the relevant legislation whether introduced in a finance act, other act of parliament, statutory instrument or other legislative instrument, and

specifically EXCLUDING

- changes in, or clarifications to, HMRC interpretation of legislation, or
- new precedents set under case law, and
- any changes that alter the cash tax charge for the DNO in the current price control period that arise specifically because of the DNO being a member of a group of companies. That is, the tax legislation will be applied as if the DNO were a standalone entity. For example, the potential restriction of interest as deductible as a result of the licensee being a member of any group of companies or partnerships will be not be a trigger event, and
- for the avoidance of doubt, any changes in accounting standards that have a knock-on effect on the quantum or timing of taxation will not be considered as a trigger event.

1.36. The trigger point is under review and will be set at Initial Proposals. It is currently estimated to be a change or changes that yield a greater than 0.5 to 1 per cent[13] increase or decrease in the total base revenue of an individual DNO, on the basis of the average annual effect over the remainder of the price control period. The trigger weakens the later in the price control period it is activated.

1.37. Consequent upon the prescribed legislative changes above, the DPCR5 model would be re-run to calculate whether the new outcomes activate the trigger. No adjustment will be made to any other assumptions used in the model. This is to ensure that any adjustment is calculated on a like-for-like basis.

1.38. Where a number of changes are enacted in a single act, those changes should be considered in total as a single adjustment rather than separately.

1.39. In practice, it is expected the trigger to be activated mainly from changes in the main rate of corporation tax or changes to the rates of capital allowances, or the allowability of expenditure as tax deductible.

1.40. Whenever the materiality threshold is breached then a tax cost allowance adjustment will be made. The options on which we seek views are whether the DNOs should retain the risk and rewards for all amounts below the threshold; or for the entire amount rather than the excess over the materiality trigger.

[13]The amount will be reviewed at Initial Proposals

Timing of revised revenues

1.41. As explained in chapter 11 in setting the timing of revised revenues, we need to balance the interests of DNOs and consumers. In considering the options, we must take account the timing of legislative changes, that affect the timing of tax instalment payments and when DUoS charges are revised.

1.42. In recent years, HM Treasury has usually signalled major changes in the rate of tax or allowances in advance, but this may not always be the case. Therefore, for the avoidance of doubt, it is important to define when the trigger event occurs. Given the uncertainty around the timing of announcements, and considering that some items included within the definition of legislative changes may not be announced in advance at all, a sensible date would be the one upon which the tax change came into effect and not the date of the announcement of any change. DNOs pay their tax liabilities in quarterly instalments, two in the current tax year and two in next tax year, so any change to their cash outflow is deferred.

1.43. DNOs' revenues are set three to four months in advance of the price control period (subject to any reference to the Competition Commission). DNOs are also required to publish updated forecasts every six months, which take into account under- and over-recoveries from the current and previous years. Currently DNOs have to submit indicative charges three months before the next financial year commences and final charges six weeks in advance. Revenues have often been smoothed (profiled) over the price control period to avoid significant volatility from year-on-year changes.

1.44. In balancing the need to avoid year-on-year volatility in charges and to protect consumers, we consider that there should be a delay between the trigger being activated and the implementation of revised revenues. However, any delay should not adversely affect DNOs financeability or one of the reasons for the trigger is defeated. The delay period could be longer dependent on the point in the price control period in which the trigger is activated and its magnitude. There are a number of options:

- a case-by-case basis to retain flexibility as has applied to other re-openers in DPCR4, e.g. ESQCR, Traffic Management Act (TMA). The disadvantage is that this does not provide regulatory certainty,

- log up all amounts until the next price control and adjust on a NPV neutral basis. This defeats the purpose of aiding financeability or if a reduction, delays reducing DUOS costs to a different generation of consumers,

- adjust in the regulatory financial year following the trigger event. If this option was chosen, then a condition could be inserted to state that this is subject to there being at least three months before the regulatory year end,

- adjust the DPCR5 revenues at the outset if the trigger event occurs at least 3 months before the start of the price control period, but after Final Proposals have been published, or

- if the event is, say three years into a price control adjust at the next price control on a NPV neutral basis. This has the same drawback as the third option.

1.45. There may be a number of trigger events occurring within one price control period, which may require more than one re-opener. If multiple events occurred and depending on their timing it may be impractical to process and amend future revenues within the price control period. Views are invited on whether there should be multiple re-openers or only the first trigger should be adjusted for in DPCR5 with subsequent triggers being adjusted ex post.

Appendix 15 - IT

1.1. The review of DNOs' IT costs is limited to the non-operational information technology (IT) activities as defined in the RRP guidelines i.e. excludes IT equipment used exclusively in the real time management of network assets such as RTU units and communication equipment receivers at the control centre. Ofgem appointed Mouchel Management Consultants to undertake the review. The following text has been provided by Mouchel.

1.2. The three pronged approach to assessing IT is:

1. Benchmarking IT costs
2. Undertaking a Qualitative review – Practices
3. Undertaking a Qualitative review – IT systems

1. Benchmarking IT Costs

1.3. Mouchel Management Consulting has been appointed to undertake the IT Benchmarking as part of DPCR5. Mouchel has a team of consultants with over 40 years of experience in successfully completing IT benchmarking studies. Mouchel complies with the European Benchmarking Code of Conduct.

1.4. Ofgem requirement: ‘Benchmarking IT costs: this will involve identifying key functional components of non-op IT e.g. desktop, server, application development, hardware etc and benchmarking the DNOs against each other and suitable external benchmarks. As part of this assessment Mouchel will be expected to assess each DNO’s performance on the key underlying costs drivers such as use of contractors, integrators, offshore developers, outsourcing etc’

The IT Benchmarking Process

1.5. There are six stages involved in IT benchmarking within DPCR5, namely; discovery, peer group selection, gap analysis, data validation and findings. These stages and key activities are shown below:

Initiation	Discovery	Selection& Normalisation	Benchmarking & Gap Analysis	Present Findings	Report& Presentations
Terms of Reference Scope Agree benchmarking approach Success Criteria Contractual Requirements Outline Deliverables	Kick Off Terms& Conditions Scope of Network Services Topology and Volumes Technology Architecture Service Targets Charges (Fixed and Variable)	Select Peer subset Agree best for benchmarking Normalise for material differences	Same 'basket of measures' for benchmarking Benchmark comparisons Identify differences Gap analysis and supporting evidence	Prepare initial findings presentation Present findings, conclusions and recommendations Identify matters arising Process matters arising	Prepare draft report Issues draft report to sponsors for improvement Issue final report Undertake presentations

1.6. **Discovery -** involves collecting relevant IT information from operating companies (who provide the IT services to DNOs) to fit our model of inter-related technology zones (as shown overleaf). We process the information from each operating company through our IT Benchmarking model to create key performance indicators (KPIs). An example of a KPI is the help desk cost per incoming call. These KPIs then become the basis for comparison with best practice peers that have been through exactly the same process beforehand. Our data collection questionnaires and models are the result of almost 20 years of continuous development and are time-proven and reliable.

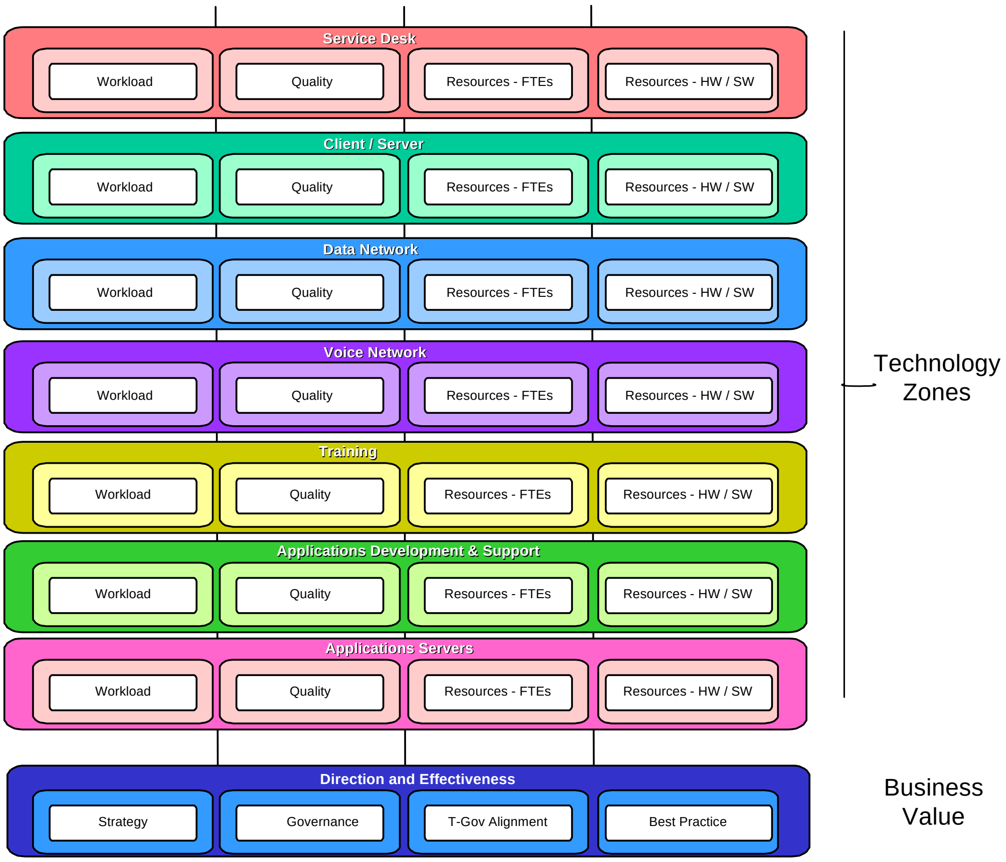
1.7. **Peer group selection –** based on the average operating company size, topology and service targets we take five similar sized organisations and create a best practice peer benchmark group. We select the peers from our extensive databank of over 250 UK organisations. For the DPCR5 study we also create an average of the seven operating companies in order to provide a DNO industry benchmark.

1.8. **Gap analysis -** involves comparing each operating company against both the industry average and best practice benchmark group. The resultant charts illustrate where industry average and benchmark unit costs are above or below the respective operating company values. This gap analysis can signify that an operating strength or an improvement opportunity exists. Note that there may be mitigation of certain values based on recent hardware investment or higher service targets.

1.9. **Data validation -** this is a workshop which reveals a number of high level KPIs to operating companies and shows where they stand to each other, the industry average and similar sized best practice benchmark. In addition, the key cost drivers that underpin unit costs are also identified.

1.10. **Findings -** this is the report of the findings to Ofgem after any final data verification has taken place following the data validation workshop. Further information defining local strengths and opportunities for improvement will be presented on-site to each operating company. Copies of these local PowerPoint reports will also be forwarded to Ofgem.

1.11. It is very important that there is an understanding of the context of reported numbers in that operating companies are at different stages all consolidation, technology refresh and so one. Contextual supporting information provides greater clarity on the operating companies' position and enables true improvement projects to emerge from behind the empirical evidence.



1.12. The above illustration shows the Mouchel Technology Zones used for IT benchmarking.

1.13. Mouchel will also use external reference material such as from the Gartner Group to cross-check our results. This form of benchmarking may be at a higher level.

2. Qualitative review - Practices

1.14. Ofgem requirements – 'Qualitative review - Practices: to complement and reinforce the benchmarking exercise, Mouchel is required to undertake a review of the efficacy of the DNOs' IT policies and practices judged against industry best practice. This will involve assessing the DNO's performance on areas such as procurement, project management (the whole cycle from design through to implementation), corporate IT strategy, use of contractors, offshore developers, effectiveness of outsourcing (where applicable) etc. The review would be expected to include reviewing key IT documents e.g. policies and project papers as well as direct interviews with DNO staff.'

1.15. We note that efficacy and effectiveness are very closely related. Efficacy is the capacity to produce an effect while effectiveness is producing an effect in real life. For example, in medicine, effectiveness relates to how well a treatment works in practice, and efficacy measures how well it works in clinical trials. Both are useful and relevant to IT.

1.16. The primary measurement of IT effectiveness is the impact of IT in reducing the unit cost of doing business. For example, this could be an IT investment (partly) leading to a reduced cost per invoice processed. Evaluating at this level requires significant effort and time.

1.17. However, over the last 10 years there has been an increasing focus by organisations to move IT from a somewhat reactive culture to a more proactive culture and operation with improved effectiveness. This is evidenced by the take-on of IT frameworks such as ITIL, CoBIT, TOGAF and so on.

1.18. All organisations are at different stages of maturity with regards to these frameworks. At Mouchel, we use the Skills Framework for the Information Age (SFIA) as a useful 87 point template which embodies competencies and services from most of the popular IT frameworks in use.

The overall IT Effectiveness Assessment Process

1.19. In essence are four activities required to assess IT effectiveness, namely; discovery, evidence review, evidence completeness and findings.

1.20. **Discovery -** involves collecting relevant IT documents, policies, procedures and supporting information from operating companies using a predefined list of IT documents and the SFIA checklist.

1.21. **Evidence Review -** involves cataloguing the evidence items from each operating company and reading the material.

1.22. **Evidence Completeness -** involves assessing the evidence for completeness and quality with regards to industry best practice.

1.23. **Findings -** this is reporting the findings by way of an Effectiveness Appraisal. This will include examples of best practice from operating companies to Ofgem and the operating companies at the data validation workshop and in the study report. Further information defining strengths and opportunities for improvement will be presented during an on-site presentation to each operating company.

3. Qualitative review – IT systems

1.24. Mouchel is required to undertake a review of the costs and functionality of the systems utilised at the DNOs and the forecasts for development or replacement of those systems in the remaining DPCR4 and DPCR5 periods. We are expected to assess the DNOs' systems in operation and identify key functional differences and compare these to the costs incurred. We are expected to review the expected benefits from the forecast replacement of IT systems and provide an assessment of the efficacy of replacement when forecast.

The overall IT Systems Review Process

1.25. In essence are four activities required to assess forecast IT systems changes, namely; discovery, systems forecast review, benefits review and findings.

1.26. **Discovery -** involves collecting relevant forecast information that has been submitted by operating companies to Ofgem on future systems changes

1.27. **Systems Forecast Review -** involves reviewing the material (including commentaries and discussions) from each operating company and understanding the reasons for potential change

1.28. Benefits Review - involves assessing the benefits from forecast changes to IT systems during the DPCR5 period.

1.29. **Findings -** this is the report of the findings to Ofgem and also presenting local information to each operating company during an on-site presentation.

In conclusion

1.30. The three work-packages are inter-dependant in so far as:

1.31. Good value IT services (IT benchmarking) are influenced by good design and practices (IT Effectiveness) which together provide confidence in future systems forecasts being accurate and benefits oriented.

Appendix 16 - Property cost review

The following text was provided by Drivers Jonas.

1. Introduction

1.1 Drivers Jonas was appointed by Ofgem in January 2009 to support its DPCR5 DNO property cost review.

1.2 The ultimate objective of the Drivers Jonas study is to advise Ofgem as to the correct revenue allowance allocation that DNOs should be granted for the DPCR5 review period.

1.3 We have been asked by Ofgem to prepare this interim Methodology Report as part of its planned update for the DPCR5 process as a whole.

1.4 This Report describes our Scope of Services, the Drivers Jonas team, and our Methodology. Although it is too early to report on specific findings, we have noted a number of emerging themes which we also reported to Ofgem earlier in March.

2. Scope

2.1 The prime aim of this study is to provide a robust view of the allowances for the non-operational property management activity each DNO should be allocated for the DPCR5 period. Buildings covered by this review include offices, training centres, call centres and depots but exclude operational sites such as substations.

2.2 The scope of Ofgem's study was outlined in its December 2008 Terms of Reference and is extracted below.

Assessment of property costs - the contractor will undertake an assessment each DNO's property costs for the last three financial years (2005-08) and develop a forecast for 2009-15. This will comprise three elements:

(a) Assessment of work space deployment – the contractor will determine whether the DNO is utilising its property portfolio efficiently by comparing relevant work space metrics within the DNOs and against appropriate external comparators. The contractor should also assess the effectiveness of the DNO's working arrangements against industry best practice e.g. workstation allocation, occupancy levels, working patterns etc

(b) Assessment of the costs of work space - the contractor will determine whether the costs of the DNO's property estate is efficient in terms of:

- unit costs e.g. cost per FTE compared within the DNOs and appropriate external comparators e.g. water companies

- rents paid on freehold or leasehold property (or equivalent charges for property owned by another part of the same group) compared to market rates in the same geographic region

(c) Assessment of facilities management (FM) costs - the contractor will assess the efficiency of DNO's FM costs by comparing appropriate unit cost measures between the DNOs and against appropriate external comparators.

3. Drivers Jonas Team

3.1 The lead consultant is Drivers Jonas, a multi-disciplined commercial property consultancy.

3.2 The Drivers Jonas team also includes two key sub consultants. The first, Investment Property Databank (IPD), is market leader in performance analysis of real estate, analysing around 70 million square meters of space annually across a range of asset classes and industry sectors. The access to its benchmark data adds significant weight and credibility to the ultimate recommendations for scale of property cost allowance.

3.3 The second sub consultant, Adryan Bell, is a recognised authority on new ways of working and efficiently using space.

4. Methodology

4.1 Our methodology mirrors the three elements specified in Ofgem's brief and is described below.

(a) Assessment of workspace deployment

4.2 In order to assess workspace deployment, space utilisation and working arrangements, we will undertake two audit activities, one based on desk analysis and a second based on site visits.

4.3 To complete the desk analysis, we have issued a Data Template to DNOs in order to collate their space data. This will allow each building to be benchmarked against relevant industry standards for "space per person" and "space per workstation" metrics in accordance with IPD's International Total Occupancy Cost Code, the most commonly used cost standard. Space will be measured on the following bases:

- Total net internal area (NIA) at individual building level.
- Total NIA of sub-let space
- Total NIA of vacant space
- Total Number of Full Time Equivalent staff (FTEs)
- Total Number of workstations

4.4 A total of twenty-seven site visits have been arranged with DNOs. These cover a wide range of building types including:

- Offices
- Depots
- Shared buildings
- Training centres

4.5 Buildings have been selected based on an analysis of DNO Template returns with the intention to identify good and poor performance. Thus we have examined cost and occupation data and focussed on those properties which have either particularly high or low metrics when compared to benchmarks – for instance, high running costs per m^2 (assumed poor performance) or high FTE density (assumed good use of space).

4.6 Having validated this information with the DNO's, we will provide analysis that allows properties to be benchmarked against appropriate external comparators and also the distribution network.

(b) (c) Assessment of Workspace costs and FM costs

4.7 We have grouped together the analysis of property costs and FM costs as the methodology is very similar for both cost types.

4.8 We have again used a Data Template, based on IPD's cost structure. This will enable us to provide Ofgem with:

- Historic analysis of costs per FTE and area metric for the DNOs against appropriate external comparators;
- Analysis of current performance regarding cost per FTE and area metric for each of the DNOs;
- DNO's performance compared against good practice in the private sector.

4.9 As part of the analysis we will also consider each DNO's Estate Strategy. This will review the quality and suitability of buildings in context of the DNO's wider business strategy. This will identify changes in:

- FTEs (including location);
- Buildings (acquisition / disposal);
- Increases / decreases in area;
- Other investment / divestment, included future capital requirements;
- Working practices;
- Procurement policies.

4.10 We will align these changes to rental growth projections and predicted operating costs.

4.11 We will also reflect other economic indicators in discussion with Ofgem, for instance RPI and rental growth which will need to accord with its general treatment of inflation in the DPCR5 review process.

4.12 This work will culminate in the development of a model which will show the predicted property activity allowance allocation for the defined periods.

Templates Issued

4.13 As noted above, the initial source of data will be obtained from Data Templates issued to DNOs. Three Templates have been designed, submitted and returned to Drivers Jonas:

Template 1 – Estate strategies and working practices

4.14 Template 1 captures the following information:

Estate Strategy - describes the portfolio, current standards and desired changes;

FM & Property Services - covers management and procurement, and future changes;

Surplus Space - cost impact, and mitigation strategy;

Working practices - how these optimise the use of space;

Business strategy - how this impacts on the Estates strategy; and

Accounting Issues – covers the impact of intra-group accounting, and use of notional charges.

Template 2 – Cost / staff / area / property details

4.15 Template 2 captures the following information:

Space details – Full Time Equivalents, Gross Internal Area and Net Internal Area;

Property details – Address and building usage;

Financial data – costs for: Real estate, Building operation, Business support, Management and Capital.

Template 3 – Seven year date forecast to 2015

4.16 Template 3 captures the following information:

Financial forecasts – in the same format as the Financial data contained in Template 2, without inflation;

Inflation forecasts – separately provided for each year and each cost heading;

Space / property / FTE data – forecast changes in number of buildings, space usage, numbers of staff

Interaction with DNOs

4.17 In February we met representatives from all DNOs, together with Ofgem, in a workshop-format designed to explain our brief and show drafts of the three Templates we wished to use.

4.18 We received useful feedback from all who attended, were able to answer questions and queries, and revise the draft Templates where appropriate.

4.19 We believe this early interaction has helped in the smooth running of the data collection process to date. Overall we have enjoyed a good response from DNOs who have been able to return Templates broadly within the timescales set out.

4.20 The interaction continues with individual queries being addressed to DNOs as we review the data supplied.

4.21 In addition to the site visits to review use of buildings and working practices, we will also be holding discussions to validate cost and metrics data and discuss early results.

5. Findings to date

5.1 For this Interim Report it is premature to form a view of the recommended cost allocation for each DNO.

5.2 However, a number of themes have emerged which are worthy of note:

- The quality of Estate Strategies varies considerably – some are well thought out, others very limited. To some extent, this may reflect the lack of clarity within Corporate Plans about the future direction of the business and its potential impact on space needs over time;
- There are few specific policies relating to flexible working practices or space standards, but most DNOs do seem to permit varying degrees of flexible working by staff;
- There is wide variation in interpretation as to what constitutes the ideal tenure model – some favour leaseholds to provide exit opportunities; others see freeholds as more flexible and secure;
- Responsibility for property also varies – some DNOs have direct control and can influence location, efficiency and costs, whereas in others the owning company controls the estate;
- Where owning companies centrally control and manage property, we anticipate that transfer pricing will be an issue when analysing DNO Template returns, especially real estate costs;
- FM activities are mainly outsourced using short-term contracts; the actual property management function varies in accordance with who controls the estate;
- Most DNO estates appear to have a significant proportion of 'heritage' buildings, often 60s / 70s, which are often reported as being in poor condition. This contrasts with newer buildings which, by definition, provide much better working conditions and more efficient layouts;
- Restrictions on recycling capital is cited by some DNOs as a reason not to make more fundamental changes in their estates;
- Data quality for rents on freehold properties (notional rents) is currently patchy, and in its current state will not provide for meaningful comparison within the DNO

group (as they have different property ownership strategies) and the wider marketplace;

- Unit costs for rates payments may not be relevant when compared to the wider market due to the DNOs benefiting from "Cumulo Rates" in many cases;
- Data quality for FM costs (and other unit costs) appears more robust (subject to final validations being returned), and will provide for analysis at DNO level and compared to the wider marketplace;
- Space data currently appears robust, and where provided there are validation queries pending with the DNO;
- The split of office to depot space (required for accurate analysis) has been requested, and has been supplied by most DNOs so far;
- Property descriptive data is currently robust and will be able to be used to distinguish between building types and will inform the analysis when considering drivers of results; and
- In arriving at a forecast revenue allowance, we will need to convert the IPD-based cost structure into the property definitions used by Ofgem.

Appendix 17 – Excluded services

1.1. In DPCR4, revenue forecasts for excluded services[14] were treated as a proxy for cost levels and those amounts were accordingly deducted from base demand revenues and the related cost allowances in the main price control settlement. Subsequently, there has been an annual adjustment for some categories of excluded services to deduct (or add) the difference between forecast and actual revenues from the total of non-fault opex costs allowed into RAV. To date, in DPCR4, the total reduction to RAV concerned has been £152m.

1.2. The existing methodology does not incentivise DNOs to provide these services since additional activity, beyond the forecast level, is effectively penalised. This may be particularly relevant to the provision of separate charging for reactive power. If the DPCR4 basis is retained in DPCR5, the disincentive effect may be aggravated owing to possible changes in the percentage level of costs admitted to RAV.

1.3. We have been reviewing the options for excluded services in DPCR5 with a view to revising the DPCR4 treatment to place an incentive on DNOs to provide high service levels and to improve transparency in respect of costs, revenues and margins. There are several options for DPCR5:

- The simplest would be to retain the current DPCR4 approach of using forecast revenues as a proxy for cost levels with a true-up each year.
- One variant on the DPCR4 methodology would be to use an all-DNO averaging approach to forecasting revenues.
- Another variant on the DPCR4 approach would be to carry out a partial true-up each year to provide some incentive for DNOs to carry out additional activity. This should mean that benefits would be shared between DNOs and customers.
- An alternative would be to apply a form of "cost plus" price control for excluded services such that allowed revenues would be ascertained from costs properly incurred plus an allowed return on the resources expended.

1.4. The first option retains the status quo and does not mitigate the issue. For the second option we would use averaged data from all DNOs to forecast revenue levels and hence costs. Those DNOs with above average activity levels would have an incentive to maintain these and those with below average levels would be encouraged to increase activity to generate more revenues. These additional revenues would be taken into account at subsequent price controls for the benefit of DUoS customers. There could be issues in applying a weighted average where some

[14] ES1,3 4,7,8 and 9 as set out at Appendix 1 to special condition A2 of the electricity distribution licence

DNOs do not currently provide a specific excluded service, e.g. charging for reactive power.

1.5. For the third option as we would only apply a partial true-up DNOs would retain some benefit from providing additional services.

1.6. For the fourth option, we would probably apply a similar process to that used in DPCR4 to notionally separate excluded services costs out of overall DPCR5 allowances in the first instance:

- Estimate amount of overall costs related to excluded services (using cost and revenue reporting data from DPCR4 to challenge/normalise).
- Deduct that amount from the additions to RAV (and the IQI) and show it as projected Excluded Services costs for DPCR5.

1.7. We would then consider the level of allowed revenues for each category of excluded services in each regulatory year to be perhaps:

100% of opex & capex costs which have been recorded against an auditable cost centre dedicated to that excluded service + ½ X | 100% of opex and capex costs which have been recorded against an auditable cost centre dedicated to that excluded service X agreed return (margin) |

1.8. The formula would allow DNOs a return at an appropriate cost of capital on the average value of capital employed during the year.

1.9. In that scenario there would be no claw back of revenues in excess of the original price control estimates subject to the formula above being applied. DNOs would need to set up dedicated cost centres that would have to be exclusive – i.e. they would have to be able to show that none of the costs could be double counted and included in totals being reported for distribution activities under the main activity headings in the RRP. The allocation of costs for particular services could be based on apportionment provided the system used was set down and reviewable. All Excluded Services revenues in excess of the allowed amount for each category - i.e. where costs had not been appropriately recorded would be subject to a RAV reduction.

1.10. This approach separates revenue restrictions for excluded services from estimates made before the start of the price control period and would have the following advantages:

- DNOs would not be penalised for providing additional levels of services and a level of return (profit) would be recognised.

- DNOs would be incentivised to collect and report accurate cost and revenue information for excluded services – as visibility improves costs for consumers may be reduced through improved organisational efficiency and peer comparison.

1.11. The potential disadvantage with this approach is that it may not incentivise DNOs to provide an accurate forecast of their excluded services revenues in the DPCR5 process and does not provide a specific mechanism to correct the position if there is a significant underforecast.

1.12. At this stage, this alternative to the DPCR4 basis has not been developed further as it may depend on DNOs' ability to amend their systems to identify the relevant costs; this has not been previously required. We will explore this option with DNOs. Views have been solicited previously on the treatment of excluded services but respondents have agreed it should be reviewed and proposed only a limited alternative to the current treatment. Views are invited on how the above option might be achieved, or any other alternative options. Should we decide to amend the DPCR4 treatment, our proposals will be set out in the Initial Proposals document for DPCR5.

1.13. In addition, we are reviewing the definitions of excluded services, e.g. revenue protection costs. We will clarify the differences between each of the excluded services, de minimis activities and the main distribution business. In DPCR4, this has not always been clear and there have been varying interpretations of the licence conditions, for example in respect of reporting proceeds from the sale of scrapped system assets. Generally, de minimis activities fall outside the definition of distribution business and are subject to a financial ceiling as set out in the licence conditions. Excluded services are broadly activities ancillary to the distribution of electricity and/or that generate revenue from the use of system assets, such as from revenue protection and separate charging arrangements for reactive power usage.

1.14. If we introduce a different treatment for excluded services from that used in DPCR4, then we will clarify the treatment of indirect costs attributable to excluded services (as well as for DG, metering and de minimis activities).

Treatment of connections

1.15. We are considering treating sole use connections as an excluded service with no relationship to the main distribution regulatory asset value (RAV). We will develop these proposals over the next few months.