DPCR5 Methodology and Initial Results Paper

Response by Central Networks

E.ON Central Networks

The photograph on the front cover was taken by employee Andy Icke, who is an Environment Advisor for Central Networks.

Contents

Introduction and Executive Summary

Ofgem's May 2009 consultation on its "Methodology and Initial Results" is a helpful statement of current thinking on a range of issues, some of which are of particular importance given the levels of uncertainty in both the economic and environmental drivers. The paper clearly identifies a number of areas where further work is required to arrive at a satisfactory regulatory framework for DPCR5.

This response is a summary of our views on the issues contained within the paper, many of which are being raised in more detail during bilateral meetings with Ofgem and in the ongoing industry working groups.

One area where we have submitted detailed views is that of cost benchmarking (Chapter 3), where we have some quite serious concerns that we have been working with Ofgem to address. A key "sense-check" is that one would expect networks with the same ownership group, very similar management policies and support processes to have broadly comparable efficiency scores. This is not currently the case for two of the ownership groups, i.e. Central Networks and ScottishPower Energy Networks. Having investigated this further, we believe that the cost benchmarking approach does not properly reflect the operating costs associated with our networks in that it:

a) fails significant statistical tests,

b) appears to be systematically biased towards smaller DNOs,

c) demonstrates a clear statistical relationship between the level of costs excluded and the apparent company efficiency.

We believe that these issues arise because individual regressions, which can be informative in their own right, give a misleading picture due to the compounding of errors when combined. Furthermore, the conclusion is also distorted by the failure to take account of particular costs such as IT&T and property. Our suggestions for complementary top-down benchmarks would solve these issues and ensure a fair representation of costs, reducing the apparent and unlikely efficiency spread between companies.

We welcome Ofgem's positive engagement on these issues, and others we have previously raised, and will seek to continue to work with Ofgem to develop the benchmarking methodology so that it gives a fair view of overall cost efficiency.

With regard to network investment, we are concerned that the approach to regulatory modelling assumes that companies are systematically suggesting unnecessarily high investment forecasts. We are acutely aware of the need to invest effectively and efficiently, and our submission is the result of a great deal of detailed planning for all areas of network expenditure. The plan incorporates the inputs of a wide range of stakeholders, and also contains the largest forecast efficiency stretch of any DNO, which further emphasises the level of scrutiny and challenge we have applied.

In over 60% of cases within the load-related investment plan, the need for network reinforcement exists already, and is therefore not dependent on forecast increases in demand.

For non-load related investment, it was widely understood and acknowledged during the DPCR4 planning process that there would be an increasing requirement for asset replacement activity due to the ageing asset base. We are consequently concerned that Ofgem's initial assessment actually results in a reduction in investment of around 18% on the DPCR4 level, and as such does not provide a robust starting point for our detailed discussions.

We are particularly keen to be actively engaged in the development of low carbon energy solutions for the UK, and have therefore proposed a plan that includes new resources to extend our engagement with distributed generation and smartgrid development, along with some advanced network investment to facilitate generation connections in those locations with abundant resources.

Network losses are a particularly important issue. We are taking a pragmatic approach here, leading work with Ofgem to better understand the problems with the current output incentive and develop a productive way forward, with a view to a methodology that all parties can accept. This does not, however, change our view that there is a need to develop a parallel framework that enhances the future management of carbon emissions. Specifically, the development and application of standards across the industry for lower loss plant would be of universal benefit.

We are disappointed that Ofgem does not believe it appropriate to provide investment in quality of supply improvements for customers. We would also question whether the use of willingness to pay information for 2008/9 can be extrapolated to the whole of the DPCR5, given the current economic conditions. Additionally, we feel that the newly-developed proposals for 'worst served customers' include an ex-post efficiency assessment that is unlikely to benefit those genuinely worst served.

We continue to be very supportive of the development of output measures that reflect the results of network investment activity. We do however believe these must be refined over time in order to ensure their robustness and to avoid any unforeseen, but perverse pressures on network investment decisions.

We support the proposed principles for equalising opex and capex incentives. A basic spreadsheet model from Ofgem would help us to understand these further, and provide more specific comments.

Our proposals for the IQI mechanism would have significantly simplified the approach to managing the undoubted levels of uncertainty, whilst smoothing prices for customers and maintaining incentives for DNOs to manage risk efficiently. We are therefore disappointed that Ofgem has not chosen to develop the suggested approach. However, we broadly agree with Ofgem's proposals for the costs suggested for inclusion in the IQI. Opex-cost baselines in the IQI should be set taking into account a forward-looking view of DNOs' workloads and plans. The use of a purely historical view to determine incentive rates would not be aligned with the underlying principles of the IQI mechanism. Costs excluded from the IQI should include those not currently in DNO plans, but that are required due to a change in policy at DPCR5 (for example, the costs of providing unmetered supplies to substations.)

On balance, our view is that most of the uncertainty faced in DPCR5 is best managed by setting an appropriate cost of capital. This places companies in a position to manage risk efficiently and effectively without exposing customers to unnecessarily volatile charges. The risks best managed outside the cost of capital are pension costs and corporation tax costs.

With regard to pensions, Central Networks has acted very effectively in ensuring that its ongoing commitments are properly contained and therefore the costs included in the plan reflect this efficient approach.

The tax trigger should be limited in terms of scope and materiality, however it should encompass non-legislative events, specifically changes in, or clarifications to, HMRC interpretation of legislation, or new precedents set under case law.

Overall, we feel that the price control process is tackling the right issues and that all parties are currently working in a constructive and open fashion. However, there is still a lot of work to do to resolve some issues that we do not find acceptable at present. We remain confident at this stage that a satisfactory conclusion is possible, and our priorities as a business remain closely aligned with Ofgem's.

Responses to Questions

Overview of FBPQ forecasts

Question 1 *What are your views on the DNO cost forecasts presented in this chapter?*

Capital Expenditure

All DNOs have forecast increases in capital expenditure in DPCR5, which reflects the ongoing and increasing need to replace equipment that was originally installed during the 1960s. This is consistent with the results of the analysis undertaken during DPCR4. It also aligns with the requirement to increase the capacity of the network to maintain the reliability of supplies to customers, and to comply with planning standards that are an obligatory requirement of Distribution Licences. Central Networks' forecasts are typical, with increases in both load-related and non-load related expenditure within the central band of submissions.

Whilst the increases in forecast expenditure are significant, the headline percentage changes highlighted within the document are misleading as the DPCR5 forecast includes a number of new requirements and also includes a forecast of the effects of future price increases. We believe the genuine like-for-like increases to be approximately half those shown at the beginning of Chapter 2.

Network Reinforcement

Ofgem has expressed some surprise at the extent of the network reinforcement forecasts in the light of the current economic climate. Whilst Figure 2.4 in the paper does not reflect our latest submitted forecast of system maximum demand it does illustrate the significant degree of uncertainty surrounding both the severity and duration of the economic downturn and the effect this will have on electricity demand across the UK. The average of the 14 DNO forecasts indicates that the maximum demand is likely to reduce by only a small amount from its current level before showing sustained growth through the DPCR5 period.

The national economic climate has, of course, influenced our forecast of maximum demand growth but, in practice, local factors at each of our major substations are much more significant in establishing the need for network reinforcement. In many cases (in fact over 60% of the schemes submitted) the need for reinforcement already exists and is not dependent on forecast increases in demand. Elsewhere ongoing local developments allow us to confidently forecast the demand growth that will require network reinforcement. Our reinforcement forecast is actually an aggregation of projects that are based on detailed local knowledge, rather than a global forecast founded on the assessment of future uncertain economic conditions.

Operational Expenditure

The comparison of operational expenditure in DPCR4 and DPCR5 highlighted in table 2.4 is also misleading as forecasts of the effects of future price increases are included. Figure 2.8 clearly shows that Real Price Effects (RPEs) are, by far, the largest factor in the headline increase. The like-for-like comparison across the industry would project a 3% increase from DPCR4 to DPCR5 whilst we are forecasting reductions in operational expenditure of 2% in CN West and 6% in CN East.

Quality of Service

We are disappointed that Ofgem has decided not to fund Quality of Service improvements as we believe that the improvements to Customer Interruptions and Customer Minutes Lost included within the submissions represent good value for money for our customers and a worthwhile improvement in network reliability.

Losses

The variation in the forecast change in losses as a result of non-discretionary expenditure by DNOs shown in table 2.8 is extremely large and suggests that different assumptions have been adopted by different DNOs.

Operational cost assessment methodology and results

Despite determined efforts by DNOs and Ofgem we do not yet have an agreed cost model that we believe gives a reliable view of efficiency, with Ofgem's analysis showing bias according to network scale and excluded costs.

We believe that a single model will never give a rounded view of efficiency and that other distinctly different views are also required to reduce the impact of error.

In addition to the statistical tests that have been carried out , Confidence Interval Analysis is required to understand the degree of certainty that can be applied when judging DNO relative efficiency as being either significantly better or worse than average.

We believe that while Engineering Management and Clerical Services costs support both opex and capex activities, these costs are better considered as part of the group of network investment support costs.

The complexity of the current model makes it difficult for DNOs to replicate the analysis. While we appreciate that Ofgem have shared their data files and scripts we need to find a way to replicate and share work more effectively and are keen to work with Ofgem and other DNOs to this end.

Question 1 *Have we exposed the correct costs to comparative benchmarking?*

The correct costs are to include in benchmarking are those which:

1. The DNO has influence over,
2. Do not introduce distortion such as costs that vary considerably over time or are unique to a certain location,

3. Are treated consistently between DNOs,
4. Are required to get a complete picture of the activity.

Ofgem's proposed exclusion of wayleaves, insurance, submarine cable faults, road costs, remote location generation and high cost low frequency faults are supported by reasons 1, 2 or 3 and so we agree this is a sensible approach.

The fact that substation electricity costs are not treated consistently between DNOs suggests they should not be included in the benchmark; however there should be scrutiny of these figures to ensure that they are compiled on a consistent basis. Would we expect these charges to reflect units distributed for example? Table 14 suggests that the values for unmetered electricity for SSE Southern and SSE Hydro are the same which would not necessarily be expected.

Similarly the distorting impact of atypical costs suggests that these should be excluded from benchmarking and this is discussed further in response to question 5.

The inclusion of the non-load related LV and HV underground cable costs is required to get a complete picture of the faults activity and we also support the inclusion of these costs. We would go further in terms of including a mixture of capex and opex costs together for benchmarking to take account of different policies or reporting which may result in differences between the balance of spend between opex and capex over the long or short term.

To see the long term effect of capital substitution then a long term capital value must be included in the benchmark. Similarly to see the impact of reporting differences, but also the impact that varying capital work has on operating costs there should be a benchmark reflecting the total spend in a year. These have been outlined in our previous paper concerning top-down benchmarking of April this year.

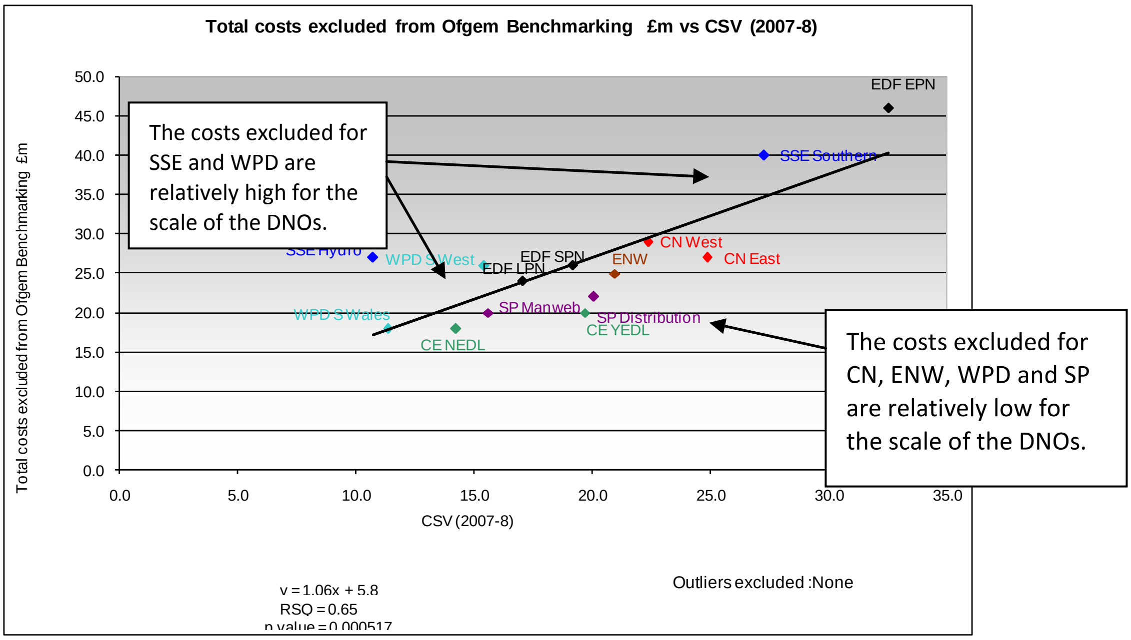
Ofgem also propose to exclude other costs that have been:

- transferred to network investment, or
- are being reviewed by specialist consultants.

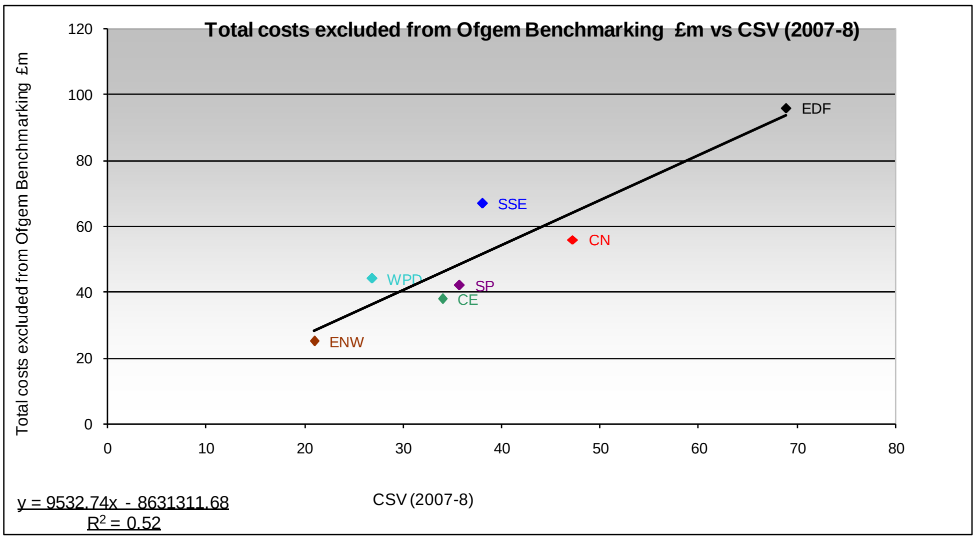
Together these make up the majority of the total costs that have been excluded.

While these cost exclusions do not initially seem unreasonable some investigation shows that the exclusions are affecting the results of the benchmarking.

Using CSV as a proxy for network scale we can see that the costs excluded from benchmarking for each DNO are not equal when normalised for network scale (below).

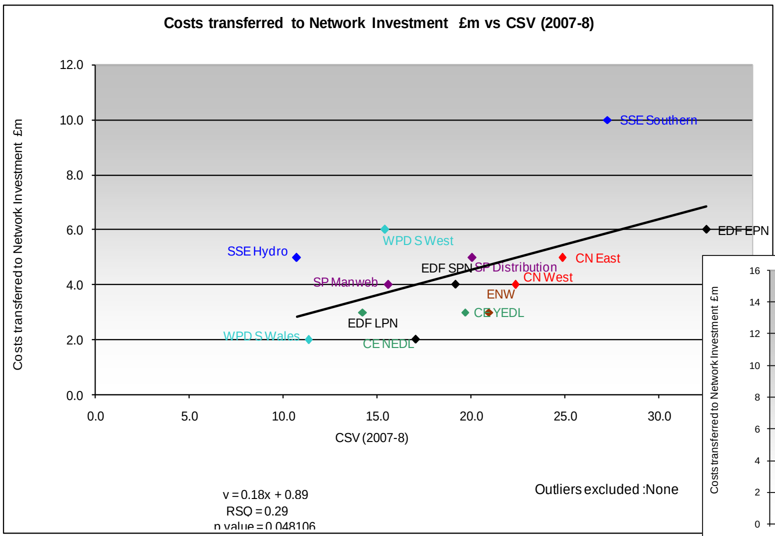


This becomes even clearer when examined on a group basis, below.

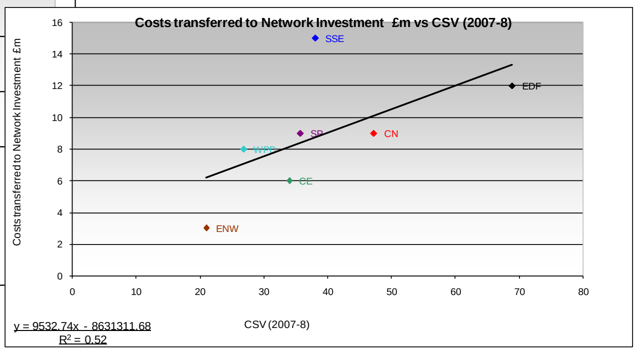


A similar picture can be seen when looking at the individual components:

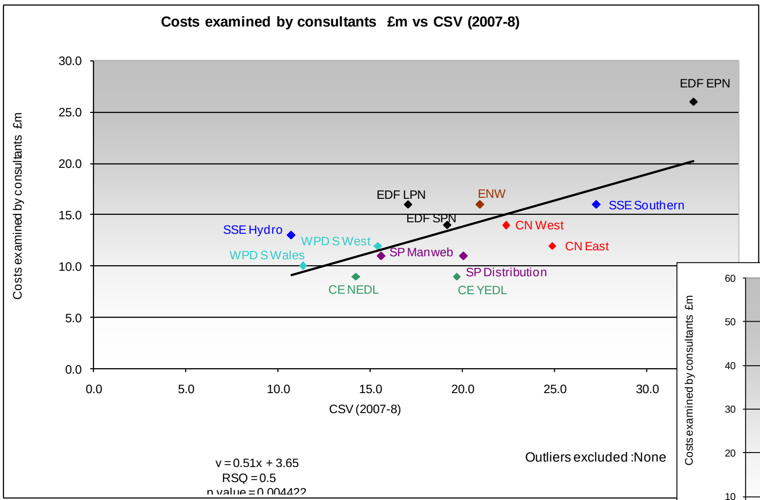
Costs Transferred to Network Investment



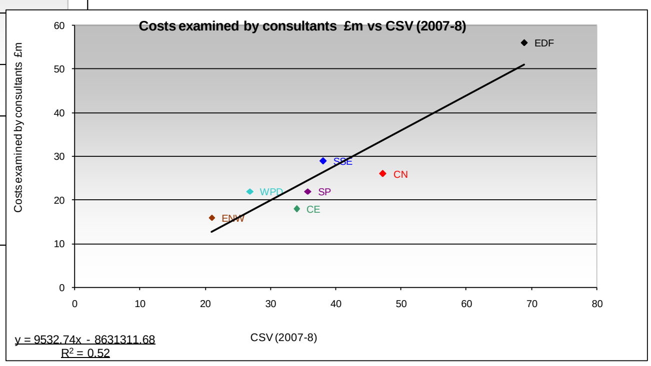
By DNO (left) and by DNO group (below)



Costs Considered by Specialist Consultants



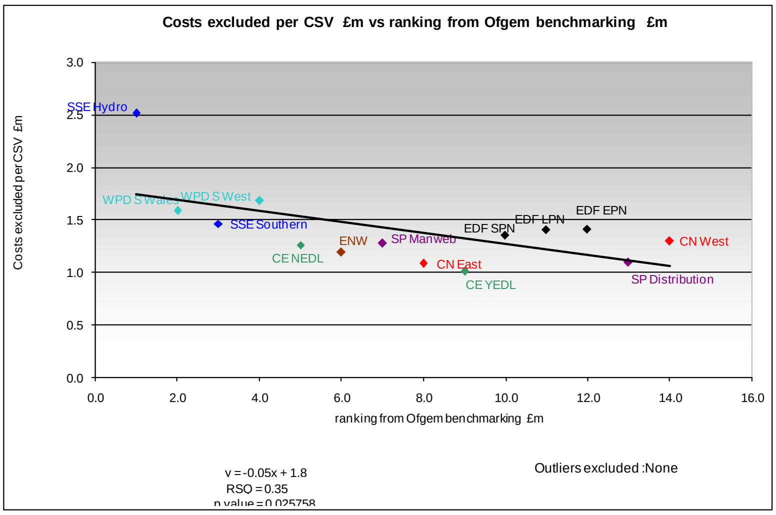
By DNO (left) and by DNO group (below)



In both these cases Central Networks' costs are low relative to network scale whereas the costs for Scottish and Southern Energy Power Distribution are high relative to network scale.

To determine whether this is affecting the benchmarking results, the cost exclusions are normalised by network scale and compared to the benchmarking results given in the methodology and initial results paper. The average of all the results given in Table 9 of Appendix 5 (with the exception of the last column which replicates the DPCR4 analysis and driver) is used to determine the average Ofgem benchmarking result and the associated rankings.

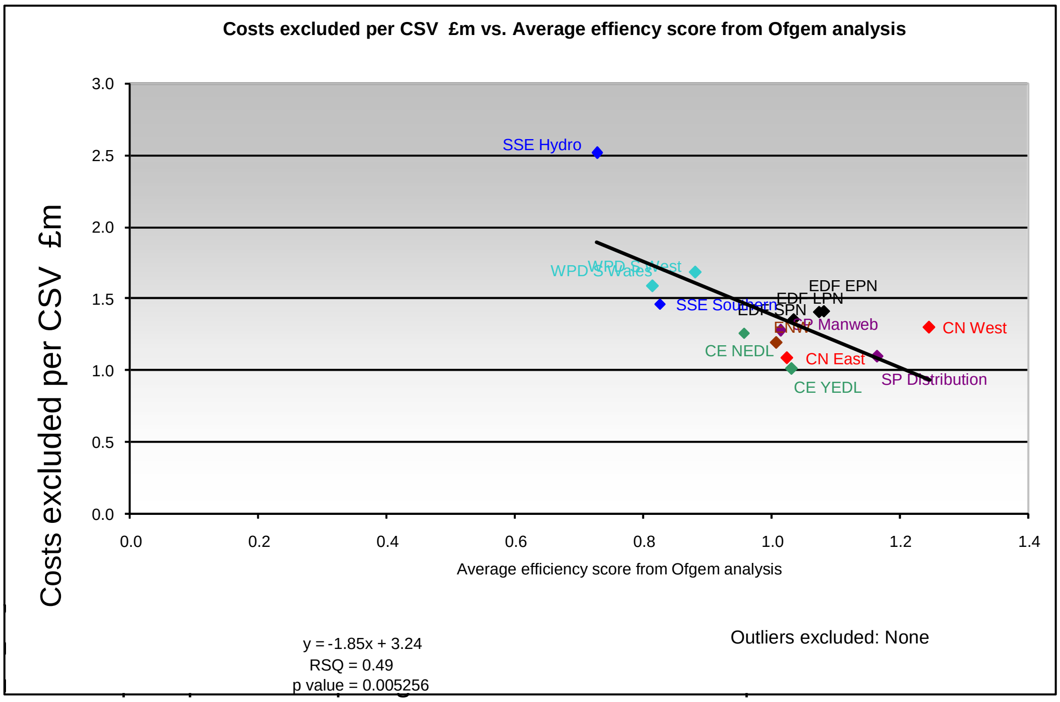
When comparing the results using either rankings or average efficiency rating it is clear that there is a relationship between the costs excluded and the overall result. (See below.)



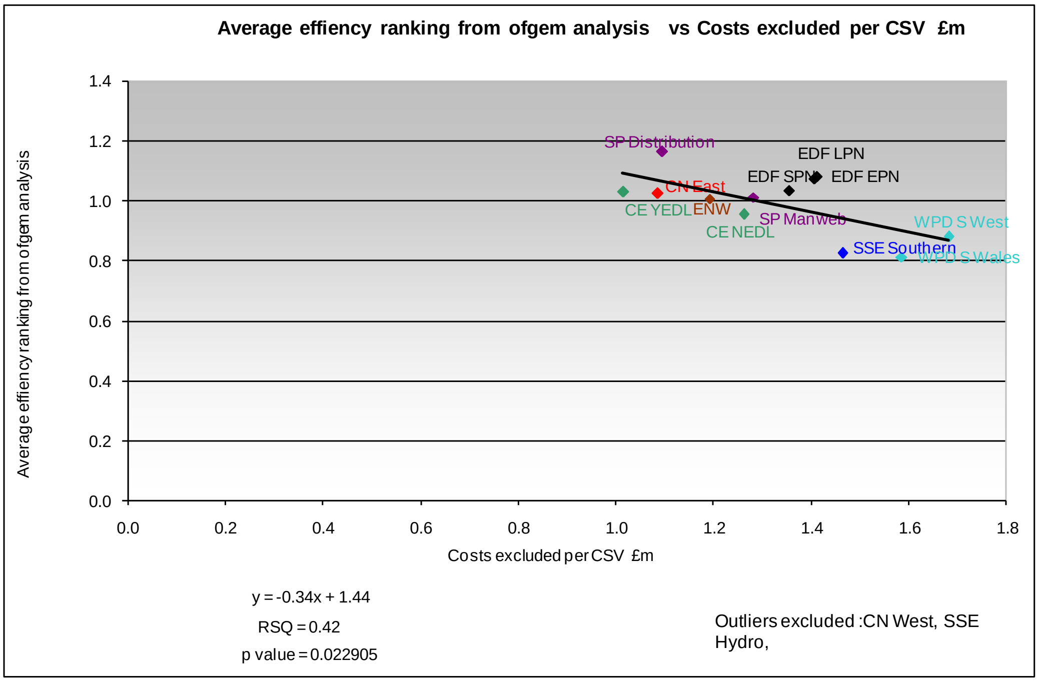
While the R squared for this chart is relatively low this is partly due to the rankings limiting the x values to integer values.

The p value suggests that the hypothesis that there is no correlation between these values can be rejected with a confidence level of over 97%.

Using the actual efficiency score gives a stronger correlation and suggests that 49% of the difference in average efficiency score from Ofgem's analysis can be explained by the differences between DNOs in cost exclusions (graph normalised for scale).



of the efficiency result. For this reason, the chart below has been redrawn to show the efficiency score as the dependent variable.



This analysis demonstrates that the costs included or excluded from the analysis have a significant effect on the results obtained. This may be why the range of the results from Ofgem's benchmarking is wider than that put forward by Central Networks as the cost exclusions exaggerate the positions of both the DNOs that are considered more and less efficient.

This also demonstrates the sensitivity of the analysis to error as only excluding a relatively small proportion of costs has a very large impact on the results. We believe that other factors with a seemingly small impact may exert undue leverage on the results such as differences in allocation of costs and the exclusion of outliers.

We believe that individual regressions, which can be informative in their own right, when combined can give a misleading picture because errors (e.g. partial misspecification of driver or failure to remove outliers) become compounded.

We have other concerns over the validity of the cost model as the resultant efficiency ratings appear to be influenced by DNO scale whether this is measured in terms of CSV, opex spend or capex spend. Further details are given in the answer to question 6.

We believe that individual regressions, which can be informative in their own right, when combined can give a misleading picture because errors (e.g. partial misspecification of driver or failure to remove outliers) become compounded.

This also raises concerns over the difficulty of combining individual activity level efficiency ratings together to obtain an overall rating. It would be difficult to include the efficiency ratings for the activities such as vehicles and transport, Property and IT together with the core result in a way that would resolve the issue as the core result would remain distorted by the cost exclusions.

This supports our view that top down benchmarking should encompass a wide range of costs to get a fuller picture. It also shows that adjustments and exclusions that may be considered to each have a minor impact can produce a compound result which has significant impact. This suggests the need for benchmarks that differ from each other in terms of the adjustments and exclusions that are applied so that any error in these does not affect all the different views of efficiency.

Question 2 *Do you agree with the assumptions we have made for our core analysis?*

We agree with most of the assumptions that have been made for the core model, specifically that:

- Related margins should be included.
- Pensions should be excluded.
- The labour cost adjustment should be limited to EDF LPN.
- No singleton adjustment should be made.

However there are some assumptions that we do not agree with which are:

- Excluding costs for alliance contracting.
- Calculating the regional cost adjustment for EDF LPN using ONS data.
- Including severe weather event costs within the benchmarking.

Alliance contracting cost exclusion

The premise behind this adjustment is that as EDF have greater visibility of their alliance contractor costs they are bound by the RRP reporting rules to present these contractors' indirect costs within the relevant activity rather than these elements being combined into the contractors' costs of the associated direct activity.

This creates an imbalance in the way costs are treated that results in EDF having higher indirect costs than a DNO that outsources work without the visibility afforded by an alliance structure. This effectively is the same situation as for any DNO which chooses to insource direct activity work as they also bear higher indirect costs rather than these costs being included in the contractors costs for direct work.

While there are good arguments to try and normalise for these differences such an adjustment needs to be applied to all DNOs rather than EDF alone. Insourcing differences are not the only cause of different levels of indirect costs between DNOs however and the degree of direct work under taken will also impact these costs. It makes little sense to normalise for insourcing without normalising for workload and so we suggest the way to deal with these issues is to:

1. Create a combined adjustment which normalises for both workload and insourcing;
2. Create a benchmark which considers total costs for the year and therefore the issue of whether these indirect costs appear on the opex or capex side becomes irrelevant.

We have put forward proposals to Ofgem of how both these options may be achieved.

The way in which the adjustment has been implemented is questionable as while we would expect it to improve EDF's score, we are surprised at the impact that it has on the scores of all other DNOs where costs should remain the same. It would be useful to see the detail of this implementation.

Calculating the Regional cost adjustment for EDF LPN

Contractors' costs regional adjustment

We are still of the opinion that large contractors do not factor London weightings into their charges and therefore the regional adjustment for EDF LPN should either be applied to direct staff costs only or should only be applied to contractors costs to a lesser degree. The application of a regional adjustment to contractor's costs is further complicated by the difficulty in determining the proportion of contractors' costs which relate to labour, suggesting that this approach may not be workable.

Use of ONS data

We believe the assumption in the core result to limit regional cost adjustments to the London area is correct. However, we believe the ONS data does not give a good view of real differences in wage levels between London and the rest of the UK due to the difficulties in:

- Matching occupation codes to DNO roles,
- The prevalence of international organisations in London, and
- The sample sizes used.

We believe it is better to determine an adjustment based on the demonstrable difference in wages and to create an adjustment that is based on the likely level of London weighting included in salary costs.

We have tried to assess the degree to which EDF LPN costs should be adjusted to account for higher wages in London, using a method reflecting likely levels of London weighting that also includes an estimate of the proportion of the activity that could not sensibly be relocated to a lower cost area. Applying this to DNO staff only suggested an adjustment for EDF LPN as low as £2.5m on a cost base calculated using the DPCR4 opex plus faults method.

Another estimate simply removes 8% percentage of labour costs (half way between the 6% Unite estimate and the 10% difference indicated in the GDN review) and 5% of contractor costs with no factoring in of the necessity for work to be located within London. This results in an adjustment in the region of £4.4m (based on 2007-8 costs applied to a DPCR4 opex plus faults cost base).

Given that some consideration of the necessity of a London location should be factored in which would reduce the adjustment further, we believe a regional labour and contractors' adjustment higher than this value is unjustified. The £7.2m adjustment suggested in the methodology paper appears to reflect the problems with using an ONS data approach.

To get another view on the scale of the adjustment, updating the regional allowance for EDF LPN determined at DPCR4 for inflation suggests that the allowance would be around £8.8m in 2007-8 prices. This allowance was intended to capture the additional costs of working in London and as such represents both the effects of higher wages and working in a highly urban environment. We don't believe the impact of working in London has increased dramatically in the last 5 years so it would be a useful crosscheck to combine the urbanity adjustment estimate with the regional labour cost estimate and compare this with the DPCR4 value.

This adjustment should be applied in a similar way to DPCR4, i.e. costs should be removed from EDF LPN for benchmarking and then added back in for allowance setting.

Severe weather atypical events

See response to Question 5.

Other proposed adjustments

Urbanity

We agree that extremely urban networks do result in higher costs, as we have found this to be the case around Birmingham. Here, the additional costs arise from the built-up nature of the environment. The concentration of the usual utility networks leads to substations and cable routes that are more complex to access and there are often additional services such as trams, underground trains which add further complexity to operations in these areas. While each DNO has some urban areas the degree of urbanity in London and Birmingham goes beyond the normal range and some definitive measure needs to be devised to distinguish zones. Zones of high urbanity may be defined in terms of business district GVA, though there may be merit in using energy density or population density measures to assist in identifying zones.

Extreme Sparsity and Interconnected Networks

We also believe there may be merit in the proposed adjustments for extreme sparsity and for the additional cost of interconnected networks. The assumptions, methods and calculations should be made available for scrutiny by all interested parties to ensure these adjustments are appropriate.

Question 3 *What are the appropriate cost drivers for each of the cost groupings?*

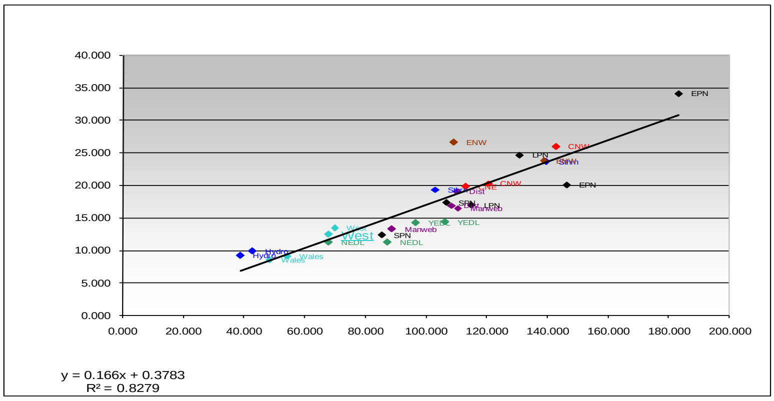
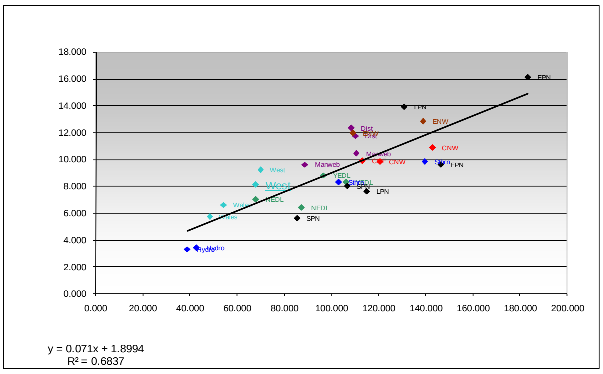
Ofgem's proposed drivers and cost groupings are reproduced below.

Table 3.1 - Cost Drivers used for core regressions of cost groupings

Drivers		**Base Regressions**	**Alternative Regressions**
LV & HV Underground Faults (including Non-Load LV & HV Underground Capex)		Total LV & HV Underground Faults	
LV & HV Overhead Faults		Total LV & HV Overhead Faults	
Non-Q of S Faults		Number of Customers	
Inspections & Maintenance		Asset Hours Work Driver for Inspections & Maintenance	
Tree Cutting		Spans Cut	
Group1	Network Design, Project Management, System Mapping	Total Network Investment spend (£m)	MEAV, Volume/Unit Cost
Group2	Engineering Management & Clerical Support, Control Centre, Call Centre, Stores and Health & Safety & Operational Training (excluding apprentice costs)	Total Direct Costs [less non-operational capex] (£m)	MEAV
Group3	Network Policy, HR & Non- Operational Training, Finance & Regulation and CEO etc.	Network MEAV	DPCR4 CSV
Single Group	As for Groups but amalgamating the three groups of costs into a single regression.	Composite Driver of drivers for Group1, Group2 and Group3	
Top Down	Single regression of all the above costs.	Composite Driver of drivers for Single Group, Faults, I&M and Tree Cutting	

Our comments on the proposed drivers and groupings are as follows:

Group	**Comment**
Faults costs groups	The costs and drivers appear reasonable here, with the proviso that exceptional event faults and costs should be excluded as these are likely to distort the analysis. (See our response to question 5 for further details)
I&M	The Asset hours work driver is an improvement on CSV if this can be made comparable between DNOs. I notice however from table 11 that this model currently fails three of the statistical tests relating to model specification, bias in panel data and heteroskedasticity. We believe that benchmarking on future costs from the FBPQ may help give an alternative view of efficiency which is subject to less distortion.
Tree cutting	Spans cut is a practical driver for current use due to the limited data available, however we are aware of reporting issues around SP's data which reflects spans managed rather than cut, which needs to be corrected for. Comparative analysis of the differences between DNOs suggests they are exposed to different infestation rates and types of vegetation which will result in very different costs to clear a span. As we

	are not yet in a position to normalise for these differences, this is likely to affect the benchmarking results. We believe in the longer term we should move towards a metric reflecting cost per tree cut. In the mean time a lesser degree of emphasis should be placed on the results from this benchmarking due to the known uncorrected distortions.
Group 1 Network Design, Project Management, System Mapping	We believe that Total Network Investment spend is a useful driver for investment related indirect costs. However, we believe EMCS costs should be included in this group. While EMCS costs support both opex and capex activities we have not yet found a way to determine the relative proportions of these and given the large variation in the detailed EMCS costs between DNOs this looks unlikely. Our analysis suggests that including EMCS within this group of costs improves the model for group 1 costs without worsening the model for group 2 costs (see charts below). Below – EMCS, ND&E, PM and system mapping costs vs. total network investment 2006-7 and 2007-8. This excludes CNE for 2007-8 as an outlier  When EMCS costs are excluded the R squared value falls from 0.83 to 0.68 (below) ND&E, PM and system mapping costs vs. total network investment 2006-7 and 2007-8. This excludes CNE for 2007-8 as an outlier.  While we believe total network investment spend is a adequate driver,

	we also support the logic behind using a metric which determines the investment made by the DNO by multiplying the volumes of assets added by their modern equivalent asset values or an average unit cost, our analysis to date has not given statistically valid results. We would like to see the detail of Ofgem's proposed metric and see whether the issues we found have been resolved.
Group 2 Engineering Management & Clerical Support, Control Centre, Call Centre, Stores and Health & Safety & Operational Training (excluding apprentice costs)	As previously stated, we believe EMCS may be better associated with the indirect costs that support network investment. The use of total direct costs as a driver could be useful in picking up differences in workload between DNOs though we consider that network scale is the major driver for these costs. Therefore we support the core and alternative drivers suggested by Ofgem.
Group3 Network Policy, HR & Non-Operational Training, Finance & Regulation and CEO etc.	We agree that the costs for HR and non-operational training and finance and regulation are proportional to network scale whether this is determined using MEAV or CSV. Network Policy is probably more of a fixed cost per DNO. As this is a relatively small proportion of the costs, however, it is acceptable to add these into this cost grouping. Similarly, no satisfactory drivers have been found for the costs within the CEO etc. group so we believe that these costs should be benchmarked by network scale as a default option.
Single Group	This uses a Composite Driver of drivers for Group 1, Group 2 and Group 3 This composite driver has been created by including each element in proportion to the percentage of the costs that are related to each driver. We have concerns that the composite approach may increase the error within the benchmarking as differences in policy or cost allocation may affect the proportions for each driver.
Top Down	This uses a Composite Driver of drivers for Single Group, Faults, I&M and Tree Cutting There are similar concerns about this composite in that it is a composite driver which includes other composites. The potential for distortion is magnified still further. This may be the reason why this model fails three of the statistical tests. Whilst Ofgem refer to this as Top-Down benchmarking, this benchmark is created in a way designed to reflect the results of the bottom up analysis in a single regression. This does not give a different and independent view from the bottom up analysis. We believe that the likely influences on costs at a top down level will be network scale and workload and therefore a simpler composite may provide a more useful alternative view.

Question 4 How should we determine baselines for the costs excluded from comparative benchmarking?

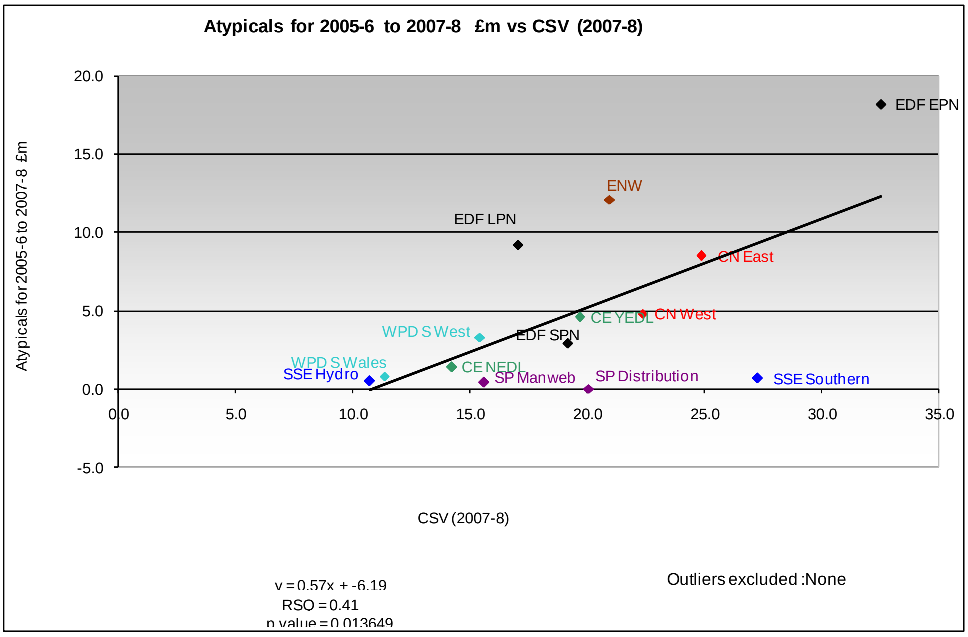
Our answers to this question are summarised in the table below:

Excluded Costs	**Comment**
Costs subject to specialist analysis Property and IT	We would expect the specialist analysis to include a view as to what average or upper quartile costs for each DNO would be.
Costs Transferred to Network Investment – Vehicles and Transport, small tools and equipment.	In the answer to Question 1 we have shown that it may be necessary to include these costs in the top down benchmarking analysis as excluding them appears to have a direct influence on the efficiency results. Therefore, the costs associated with these activities may be included in the results from the top down benchmark and not require base costs setting separately. If included in a top down benchmark, these costs would need to be adjusted to normalise for capex workload and the degree of insourcing. The costs could be benchmarked by the number of direct FTE as a crosscheck, though there would be reluctance among DNOs to use FTE as a driver.
Non Op Capex	A four year average would be a good way to determine baseline costs for this activity as previous levels of investment are unlikely to be a good predictor of future requirements, nor is there a "correct" level of this expenditure that DNOs should aspire to. This would appear to be a case where there is little alternative other than an examination of the FBPQ costs and assumptions.
Other Indirect costs excluded – Wayleaves, Insurance, Road Costs, Submarine Cable faults, Remote location generation.	As these cannot be reasonably validated by benchmarking, this may be another case where baseline costs may need to be based on FBPQ costs following scrutiny and challenge where appropriate.
Unmetered electricity	Unmetered electricity relates to items such as street lighting and electricity used within substations. This is not expected to vary greatly according to the underlying economy. It may be suitable to use an average value from the last three or four years to set annual allowances.
High value, low volume fault costs.	Again, an average cost over 4 years may not be a suitable way to determine baseline costs due to the site and incident specific nature of these costs. There may also be a high variation in whether the repair work is classified as opex or non load capex for these items. It is likely that the FBPQ projections were made on the basis of longer term analysis or additional information that is not available via the RRP and if the FBPQ methodology is

	considered rigorous then the cost projections should be accepted as baseline costs.

Question 5   How should we treat atypical costs in the price control settlement?

The atypical costs per DNO vary widely and do not follow network scale as shown below.

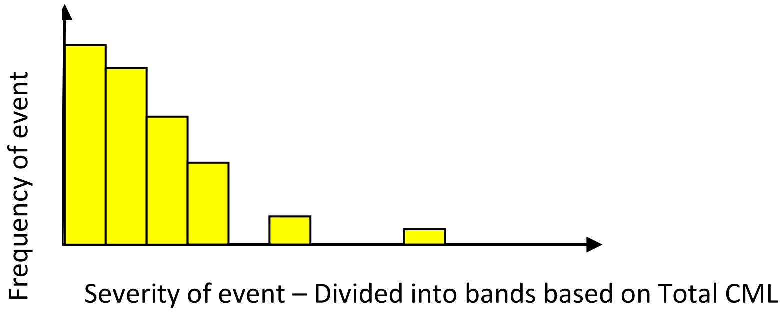


As these costs represent non-recurring costs that do not reflect business as usual it is normal practice to exclude these from benchmarking.

Severe weather

A significant component of atypicals relates to severe weather events. While cost data for severe weather events is limited to a few years we have a better bank of IIS data for exceptional events and may be able to use this information to determine the appropriate long term averages. Firstly it will be necessary to determine whether CIs or CMLs per event give a useful correlation with event costs. It is expected that CMLs would represent both the scale and the duration of the event better than CIs which may be high for lightning events. Events for the last 10-15 years could then be categorised using total CMLs as an indication of severity and therefore cost, which could then be used to determine the likely long term average cost for exceptional events.

Example of the kind of frequency distribution chart that could be compiled for exceptional events



Other atypical costs

The other atypical costs would not necessarily be expected to normalise over time and should be subject to careful scrutiny.

Question 6 What weight should we give to the benchmarking relative to other considerations?

The weight given to the benchmarking should reflect the confidence that can be placed in the results. At the moment, little confidence can be placed in the results from the methodology and initial results paper as

- The majority of the models are influenced by the costs which have been excluded and network scale. This suggests the model is, in econometric terms, not correctly specified.
- While there are many variations of the same model there are insufficient distinct top down models to view efficiency from a variety of standpoints e.g. including long term opex-capex tradeoffs or normalising for workload and reporting differences in a single year.
- Even well specified benchmarking models are still subject to error which may be more significant than the differences in efficiency between DNOs.

Incorrectly specified cost model

The shared modelling files for each activity show that the correlations between individual activities and drivers have low r squared values. This is likely to be similar for the activity groups used in the bottom up benchmarking and are the building blocks of Ofgem's top down model. Many of the models fail the statistical tests as shown in table 11 of Appendix 5 which raises questions as to whether the cost models are acceptable.

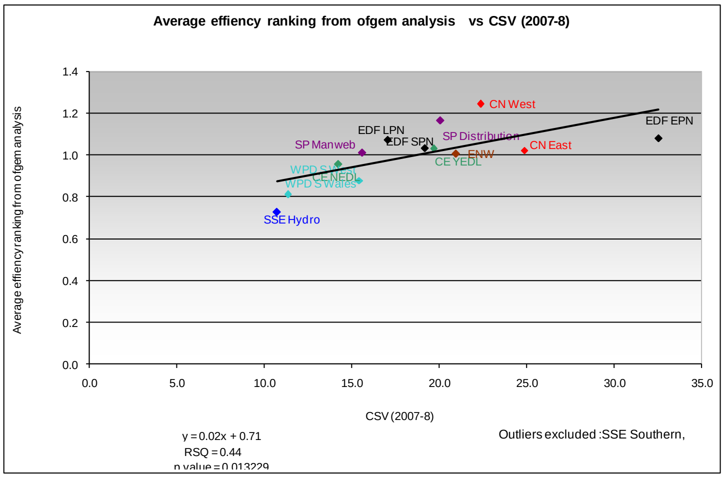
There are other indicators that the model is not correctly specified. For example, the efficiency result for a correctly specified model should not be related to:

- the costs that have been excluded (see answer to question 1),
- the scale of the DNO,
- its capex spend, or

- the actual value of the opex spend.

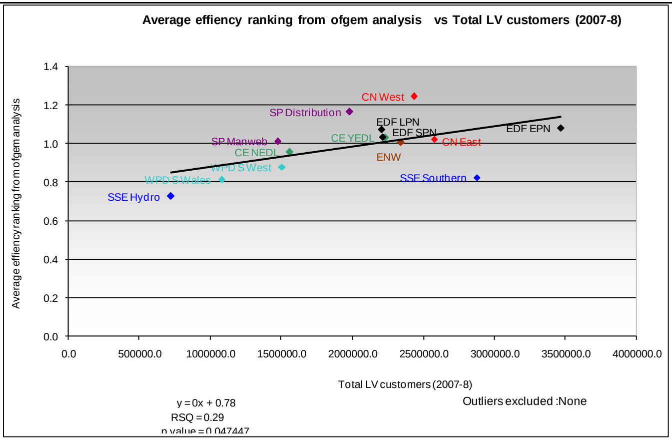
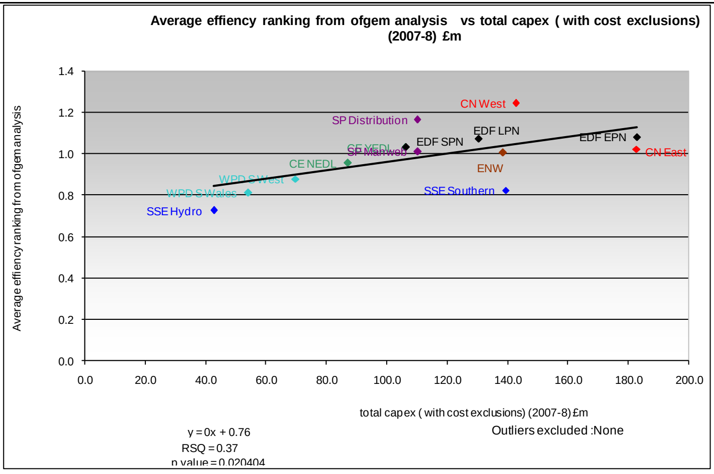
However, in addition to the relationship demonstrated in the response to question 1 between the excluded costs and the efficiency results there appears to be correlation to these items.

Network Scale, Capex and Opex spend

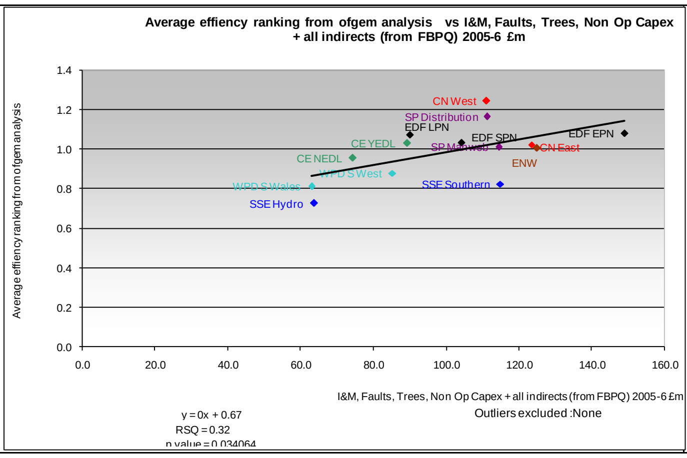


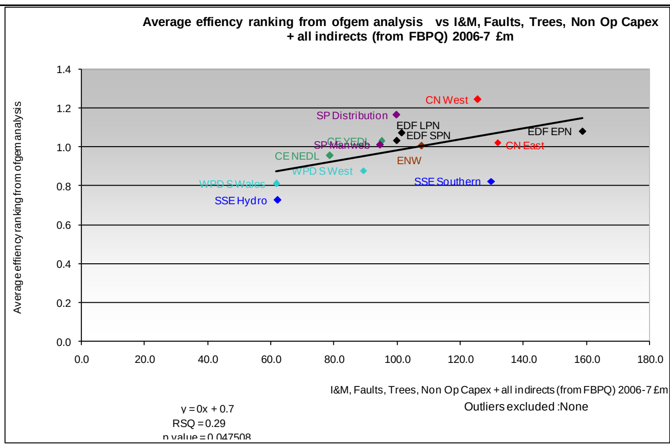
The average efficiency score is related to network scale expressed as CSV or in terms of number of customers, such that larger DNOs are more likely to have worse efficiency scores.

Similar relationships can be observed between the efficiency rankings and number of LV customers, Opex or Capex spend indicating bias in the cost model (next page).

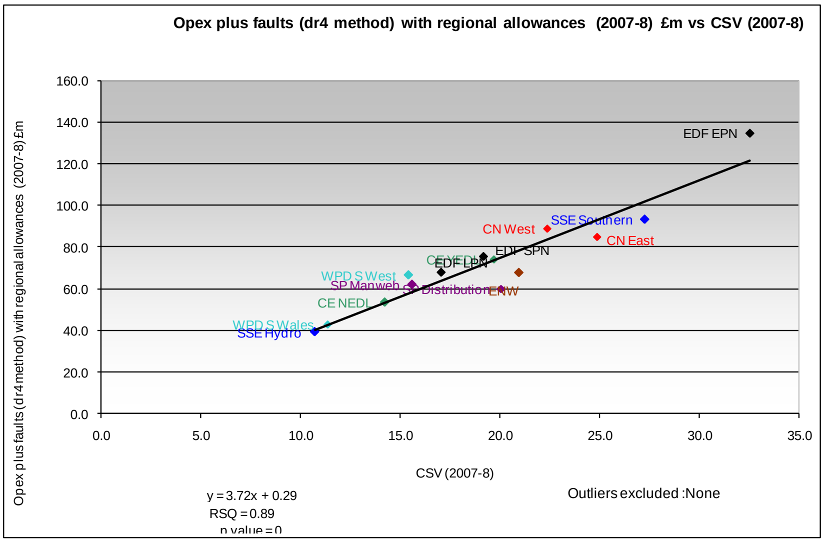
Total LV Customers	Total Opex spend
	

Capex Spend

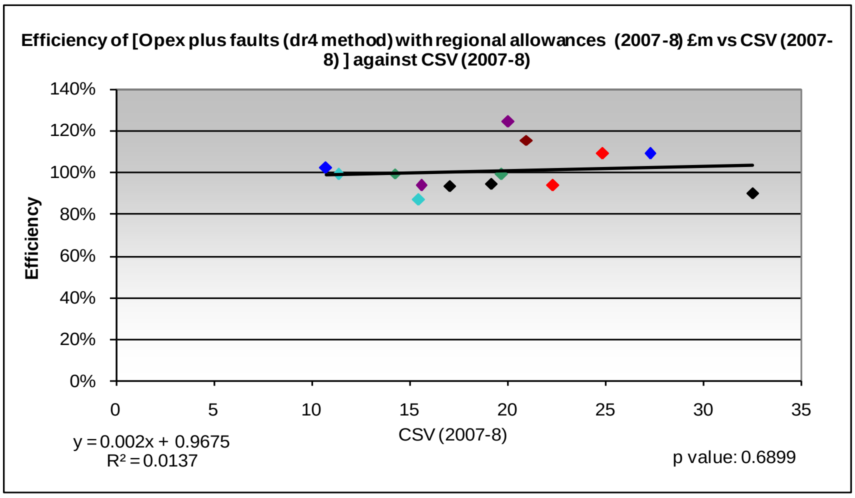




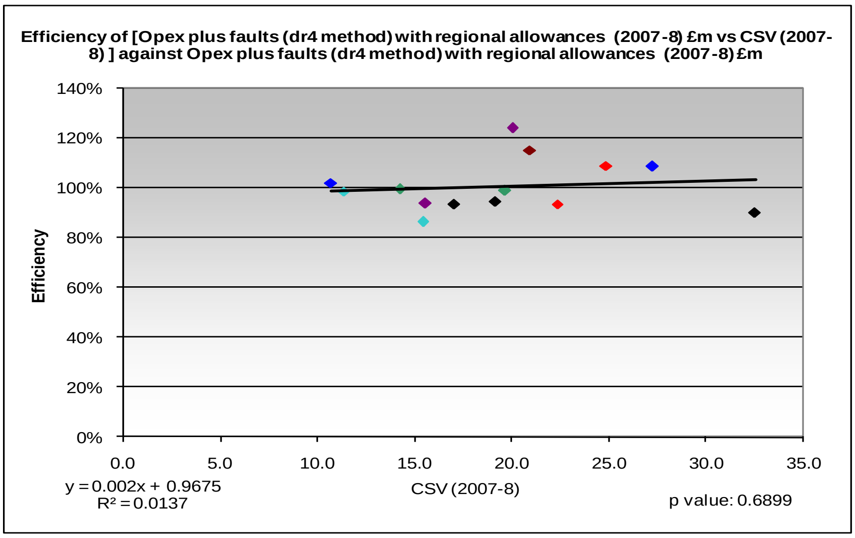
In contrast to this the DPCR4 style regression against CSV does not show these relationships to the calculated efficiency.



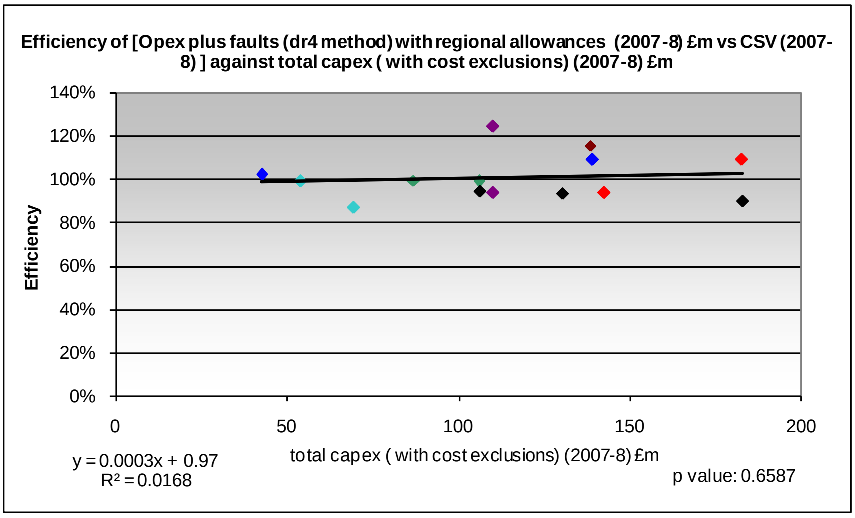
DPCR4 style regression of operating costs vs. network scale



The calculated efficiency for each DNO does not show a demonstrable link to network scale.



The calculated efficiency for each DNO does not show a demonstrable link to the opex costs.



The calculated efficiency for each DNO does not show a demonstrable link to capex spend.

Concurrence between different benchmarking results

The number of credible but distinct and different benchmarks used will also determine the degree of confidence that can be given to the benchmarking results. When interpreting the results it is clear that if a minor modification is made to a benchmark that only minor differences may be seen in the results. While this may prove that the modification has limited impact it does not necessarily prove that either result is correct. Therefore we believe that without considering a wide range of distinct, different but credible benchmarks that little confidence can be given to the "base option" even if there are many variations showing similar results.

Error within a correctly specified model

Even with a correctly specified model not all of the difference between the actual costs and the regression costs can be attributed to inefficiency. The analysis put forward for DPCR4 by Professor Tom Weyman-Jones suggested that the majority of the difference could be attributed to error rather than inefficiency. This suggested that the analysis could not prove to a high level of confidence that the DNOs with the lowest efficiency scores under that method were not in fact performing in line with the industry average. This assertion should be tested again to determine the level of confidence that can be applied to the benchmarking results.

Combining Benchmarking with the FBPQ information

DNOs forecast expenditure within the FBPQ will need to be considered when translating benchmarking results into an overall view of efficiency and then allowances. This is especially an issue given the proposed inclusion of some operating costs within the IQI mechanism.

The FBPQ data can help in forming a judgement of DNOs efficiency. For example forward looking benchmarking may be useful in getting a clearer view of DNOs controllable I&M costs as these are less affected by the unplanned additional work that can make benchmarking difficult. Where DNOs have provided clarity and detail within the FBPQ commentary as to how the cost forecasts have been developed there may be greater confidence in these values than those derived from benchmarking estimates. Forward looking benchmarking should be used as a cross check to the validity of the results in terms of the divergence between DNOs. When comparing results it must be remembered that we have included challenging cost reduction targets within our business plan.

Methodology – Core network investment

Question 1 *Do you agree with Ofgem's approach to assessing core network investment allowances based on the wide range of evidence detailed in the chapter?*

The detailed planning process for the distribution network includes a complex interaction between a number of factors that cannot be incorporated into a simple model. We therefore welcome Ofgem's acknowledgement that there cannot be a hard link between the output of network models and the proposed allowance.

Whilst agreeing generally with the assertion that reinforcement and asset replacement are amenable to benchmarking, this must be undertaken with great care. The current network need depends critically on how the network has developed over time and this will be different for the particular assets, history and circumstances within each DNO. Benchmarking that ignores these differences is almost certain to result in inappropriate conclusions.

Question 2 *Do you agree with the primary network general reinforcement modelling methodology that Ofgem has adopted for DPCR5?*

We support Ofgem's focus on modelling only those parts of the network that will generate a reinforcement requirement. Whilst this approach goes some way to recognising the current needs of DNOs that have avoided early reinforcement in the past, using a ratio that evaluates only forecast demand growth may produce a relatively high (unfavourable) result for schemes that are currently justified by their existing demand but have only modest future growth.

The analysis has, however, identified that our submission is efficient both in terms of the capacity added and the relative cost of adding that capacity. However, because of the complex nature of some of our networks, it was not possible to evaluate, within the timescale requested, either the Maximum Demand growth or the firm capacity added as defined by the supplementary question for a number of circuit related projects. These projects have, correctly, been excluded from the analysis, but we believe the suggested conclusion that adding them would take our ratios of capacity added to MD growth 'well above the industry average' to be inappropriate without being founded on accurate data.

Question 3 *Do you agree with the asset replacement modelling methodology that Ofgem has adopted for DPCR5?*

We support the use of an age based asset survivor model for medium term forecasting of asset replacement requirements. In the absence of detailed condition information for all assets and, more critically, an asset degradation prediction methodology that works reliably to the point of end of life, the survivor model provides the most reliable method of predicting asset replacement requirements in the medium term. The methodology was adopted by both Ofgem and the DNOs during DPCR4 planning and has been used in this way for our secondary asset replacement forecast for DPCR5.

We have, however, a number of significant concerns about the way the modelling technique has been used as described in the methodology and initial results paper.

Firstly the model has been used to calculate an implied life of assets based on replacements carried out during the DPCR4 period. We believe that this is too short a period to draw any meaningful conclusions about the long term asset replacement requirements. The actual replacement of assets can vary for a variety of reasons associated with both identified asset conditions and delivery constraints which may not be directly related to the long term needs of the asset. We have carried out a similar calculation but based on a longer period of time as a 'sense check' on our asset lives and we believe this to be a more valid use of the technique.

Secondly, an industry average of the DPCR4 implied lives has been developed which, of course, suffers from the deficiencies identified above, but multiplied by 14 as a result of factors which will affect each DNO differently.

Thirdly, asset lives have been derived from the DPCR5 forecasts of the DNOs to produce an average forecast life for the industry. The Ofgem derived lives for our secondary assets are very similar to those used to generate our own forecast, which is to be expected since Ofgem has used the same model as us. However, the lives ascribed to assets, either overtly or by implication, can vary between DNOs as they depend upon;

- The original equipment purchased,
- Where it is installed,
- The way it has been maintained,
- The ability of the DNO to predict end of life, and
- The DNOs' particular tolerance to risk.

We are concerned that the adoption of an average life Ofgem is effectively ignoring the existence and impact of these valid differences.

In producing its analysis of asset replacement across the industry Ofgem has used the longer implied life from the industry DPCR4 actual and the industry DPCR5 forecast on the assumption that this represents 'best practice' that any DNO could adopt for each individual asset. This assumption effectively skews the analysis to produce a 'virtual DNO' that cannot be replicated, and the predominantly red appearance of Table 4.3 supports this. The effect will be exacerbated if the model is used to set allowances since it is proposed that there will be no 'upside' for DNOs who have forecast a longer life for an individual asset type than the industry average. In this case the allowance will be as forecast by the DNO. The result of the systematic bias would therefore be a reduction in the asset replacement forecast for all DNOs, with the possible exception of EDF LPN who are unique in forecasting a reduction in non-load replacement investment in DPCR5.

Our view is that the DNOs are in the best position to identify the replacement needs of their network and that many of the factors that influence this are inherent or inherited and cannot be altered in the short term. We therefore conclude that the analysis undertaken does not actually provide the required 'robust starting point' for asset replacement discussions.

Question 4   *Is the outlined process for developing Initial Proposals suitable?*

Whilst the process outlined in the document is reasonable, there appears to be a general underlying assumption that DNOs are submitting inflated forecasts. This is certainly not the case for Central Networks, where we have genuinely sought to build a plan that meets the needs of the network and is in the customers' interests in both the short and long term.

Network investment – Environment

Question 1 Do you agree with our approach to assessing the forecasts of distributed generation, discretionary expenditure and losses and are there any other factors that we need to take into consideration?

In answer to this question we have broken the response into the following sections covering the key environmental issues to be taken into consideration within the DPCR5 settlement:

- Distributed Generation
- Innovation and Resources
- Smart Metering
- Facilitation of Lower Carbon Economy
- Losses
- Other Environmental Issues

Distributed Generation

There is much uncertainty over the future uptake of Distributed Energy. Complex factors such as emerging government policy for feed-in tariffs, the recent establishment of the Infrastructure Planning Commission and the limitations on connection of generators to the national grid all dictate the volume, capacity, timings, types & location of connections.

The Secretary of State for Energy and Climate Change has committed to providing more clarity on the future UK energy mix and details of potential government intervention to address the concerns that the binding 2020 targets may not be met. This so called "Government Summer Strategy" will perhaps give more detail prior to the completion of the DPCR5 settlement.

The business plan forecast for DG connections is based upon a pragmatic estimate developed from stakeholder's assessment of progress towards binding UK 2020 targets in 2015, data from RESTATS, BERR micro DG scenarios, local knowledge and our own future energy scenario modelling.

With such uncertainty, we are resolute in our belief that in a dynamically changing energy market, flexibility in DG connection capex and significant DG incentives should form critical components of the price control policy and settlement.

As the Ofgem analysis in the Methodology and Initial Results Paper has indicated, there is a wide variance in the cost of connecting DG to distribution networks. This variance is primarily a result the relatively low volumes of DG connected throughout current and previous price control periods, but can also be affected by location specific costs. We therefore feel it is difficult to draw conclusions from historical data in order to arrive at an average cost per MW connected, and in particular to disaggregate this by either fuel type, capacity or connection voltage.

In addition, we believe that costs for DG connections are likely to increase over time as the network becomes more "saturated". We also estimate that the proportion of shared use assets will rise in proportion to the density of DG connection requests (the density being driven by much greater volumes).

Consequently, we have used our own estimates for an average DG connection cost per MW and have applied this to all voltages. These "normalised" unit connection costs have been consistently applied to each full type and cost element (UoS, Shared and Sole use assets). The only exception is for micro DG where the UoS connection cost has been applied at a discounted rate of 50%, in addition to the assumption that only 10% of these connections will trigger reinforcement.

Such "normalised" unit costs will clearly show variations to actual quotations, and make detailed RRP reporting hard to reconcile to the planning estimates. We do however believe there should be sufficient volumes to allow for these differences to balance one another out when reviewing total costs for a programme of connections or similar magnitude to that estimated in the FBPQ.

As a consequence of such wide variances in historical unit costs we appreciate that it is also difficult for Ofgem to set an accurate DG incentive rate. We therefore welcome the indications at the Environmental Working Group that the level will be similar to DPCR4 (once the adjustment for a proportion of shared use assets is factored in).

Innovation and Resources

Central Networks is keen to take its part in the development of the low carbon future, and has proposed a range of pragmatic actions and investments within the FBPQ. The investment outlined in the discretionary table represents those items where there is already a clear need or a very high probability for the investment planned.

Our proposed projects are associated with field deployments of technologies and solutions identified in IFI during DPCR4. A further initiative applies intelligence to larger DG at critical points in support of active network management techniques. The final project (for CN East only) is strategic network investment to support future DG connections in a "wind rich" section of the eastern coastline.

Unfortunately, due to uncertainty of the UK's future energy landscape, there is little clarity on the detail of what further projects are needed for the 5 year period. We therefore believe that the Innovation Incentive should be the mechanism by which solutions that emerge during the period will be delivered. Continued investment in R&D through IFI and a modular Innovation Incentive mechanism will facilitate the development of new technologies, allowing us to conduct field trials, innovate on customer connections, find novel means to address emerging network issues and collaborate with other DNOs, agencies and partners in "lighthouse" demonstrations.

It is widely acknowledged that such innovation requires additional resources, with the appropriate skills. One item specifically included in our business plan was the introduction of a more proactive service for distributed generation inquiries and developments. This requires the incubation of skills, and we have suggested that the costs for at least six staff should be ring fenced to assist this growth. These costs are currently incorporated in the indirect cost area, though we could resubmit the data with this item included within LR7 if more appropriate.

An innovation incentive of the scale proposed by Ofgem (about £100m per year) would allow the DNOs to take a more leading role in facilitating delivery of the 20/20/20 vision and ensure that appropriate projects are instigated to ensure that the network evolves to cater for the short, medium and long term needs of customers.

Smart Metering

We have developed our view on the functional requirements for smart metering (a critical component of a Smart Network) and rollout arrangements that provide the most effective implementation and delivery of future smart grid functionality. However, government consultation is currently incomplete, and we have therefore not included any costs in the plan for the implementation of smart metering, or the introduction of data management systems to interface with network design or outage management arrangements.

Whilst we appreciate the merits of the DNO 'smart metering' scheme outlined in Table 5.3, we do have strong reservations about the strength of a supporting business case for such a high cost installation. However, should the business case be considered to be favourable by Ofgem, we would certainly expect such a solution and the associated investment allowance to be similarly made available to Central Networks.

Finally, Central Networks have been engaging with a number of different businesses with regards to the inherent link between Smart Metering and Smart Networks and are in the process of building a view on what our preferred communication method would be in order to ensure that DNOs and Retail businesses can realise the full benefits of a Smart Metering roll-out. DNOs have a unique position and hence a responsibility to ensure that Smart Meters are rolled out effectively and they complement a broader programme of Smart Network development. We will therefore continue to engage with other DNOs, Ofgem, ENA and ERA on this matter over the coming months.

Facilitation of Low Carbon Energy

Due to uncertainty over the details about the makeup of the future energy mix, there are similar implications to that described in the DG section above for potentially significant growth in electricity demand resulting from fuel substitution. Lower carbon heating systems such as GSHP and ASHP, electric and hybrid vehicles have the potential to become "mainstream" much quicker than we have currently planned for. Initial mitigations for lower volumes can undoubtedly be achieved through both traditional and innovative means, however mass deployment and "hotspots" will raise additional concerns.

For example in the case of heat pumps, it is widely acknowledged that 50% of the UK's carbon production is associated with heat demands. Heat pump installations certainly have the potential to provide heat very efficiently, and we have very recently started to see a rapid increase in requests for the connection of such installations. Our early experience is already identifying the need for careful network and installation design, and signals quite significant network reinforcement requirements, sometimes as high as £30k for individual installations. On the assumption that society values the carbon reduction contribution, it is therefore apparent that we need to develop a framework for the associated upstream reinforcement, perhaps by assuming a shallow connection charge regime specifically for such 'green' installations. Alternatively the proposed renewable heat incentive could include an element designed to subsidise the customer proportion of the cost of network upstream reinforcement cost.

In the case of electric vehicles, although we have yet to see large volumes of alternative fuelled vehicles or localised "hotspots" of electric vehicle charging, depending on government incentives and technology developments (particularly the need for three phase and / or 60A charging) , it is possible that we experience similar network reinforcement requirements to those described above. A similar framework for the local connection and associated upstream reinforcement needs to be developed.

We continue to advocate a consistent connections boundary for demand and DG. There are therefore similar arguments for moving the connection boundary to a shallower regime for DG, or incorporating an element of the proposed feed-in tariff specifically aimed at covering the cost of upstream reinforcement.

Losses

We have included in the FBPQ tables three items which yield the greatest CO_2 saving from the additional investment. We are planning to identify further areas and aim to use the IFI and Innovation Incentive schemes to carry out further investigates into both technological and operational solutions.

Central Networks is committed to the reduction of the carbon footprint of the network and network business and will continue to work with Ofgem and the DNOs on the development of an appropriate framework for a future incentive arrangement. In developing such a framework it is important to recognise the likelihood that the network carbon footprint will actually increase with the new demands of electric heat and transport, whilst the overall level of societal carbon will be significantly reduced by the facilitation of these new loads.

Whilst we absolutely appreciate the desire to construct a purely output based measure, we do still believe there is merit in the introduction pragmatic input and 'quasi- output' arrangements. Specifically, the development and application of standards across the industry for lower loss plant would be of universal benefit. Losses improvements could also be quite simply assessed by the application of scheme specific lower loss designs to true or assumed network demand profiles to generate a losses reduction register.

Central Networks is engaged with the other DNOs and Ofgem in respect of losses, and is leading for the DNOs on the work commissioned from Engage Consulting. Engage has already provided some very useful data and information, which we have shared with Ofgem, and we look forward to the culmination of their work later this month.

For the losses incentive, as with many aspects of the price control, the devil is very much in the detail. We have raised concerns with Ofgem about the detailed workings of proposed 'losses roller', which has the potential to produce very undesirable consequences, and will continue to work closely with Ofgem on this and other aspects of the losses incentive. Our aim is to arrive at a simple, fair and justifiable incentive, which will drive the right behaviours in DNOs.

Ongoing efficiencies and input prices

In setting out its proposed approach to setting efficiency targets Ofgem has recognised that DNOs can no longer be expected to continue improving efficiency at the same rate as during the post privatisation period. We share this view and broadly agree with the approach set out to establish an appropriate efficiency assumption for DPCR5.

Question 1 Have we identified the most relevant unit cost and productivity measures from other sectors to help inform our ongoing efficiency assumption for DPCR5?

Ofgem has stated its intention to build on the approach to productivity developed during the Gas Distribution Price Control Review (GDPCR), and in particular proposes to assume constant capital input in the calculation of all productivity and unit cost trends. As was highlighted at the time[1] the method used during GDPCR was misleading and we would encourage Ofgem to ensure that developments of the method for DPCR5 do not repeat the same error.

We note that Ofgem are examining both value added and gross output measures of productivity and unit cost and believe that this is the right approach at this stage.

Scope for efficiency improvements - International comparison

The comparison with US DNOs is difficult to evaluate due to the lack of detail presented as to how the analysis was carried out and how the values were normalised between UK and US DNOs. For example, it is not clear whether UK regulatory opex is being compared to US statutory opex values, which would make US DNOs appear artificially efficient. The normalisations applied by Cap Gemini in their recent European benchmarking study are given below and show how many different factors could influence international benchmarking results.

Cap Gemini Benchmarking Adjustments

Structural (Long term) cost adjustments. This adjustment intends to take into account the effects of the structure of the network and the local operating environment on costs (the consumption density, the quantity of operated network, the local operating environment and the rate of network burial);

Network perimeter adjustment. The DNOs do not operate the same number of voltage levels and this generates structural differences in their costs;

[1] See First Economics report "The 2007 Gas Distribution Price Control Review: Top-down Analysis of the Scope for Real Terms Cost Reductions –A Follow-up Note Prepared for the GDNs October 2007" available at

http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/NGG - Response - First Economics - Non Confidential.pdf

Adjustment from the impact of economies of scale. The scale effect corresponds to the correction applied to take account of the fact that a smaller DNO is at a disadvantage compared with a larger DNO, due to the scale of activity**.**

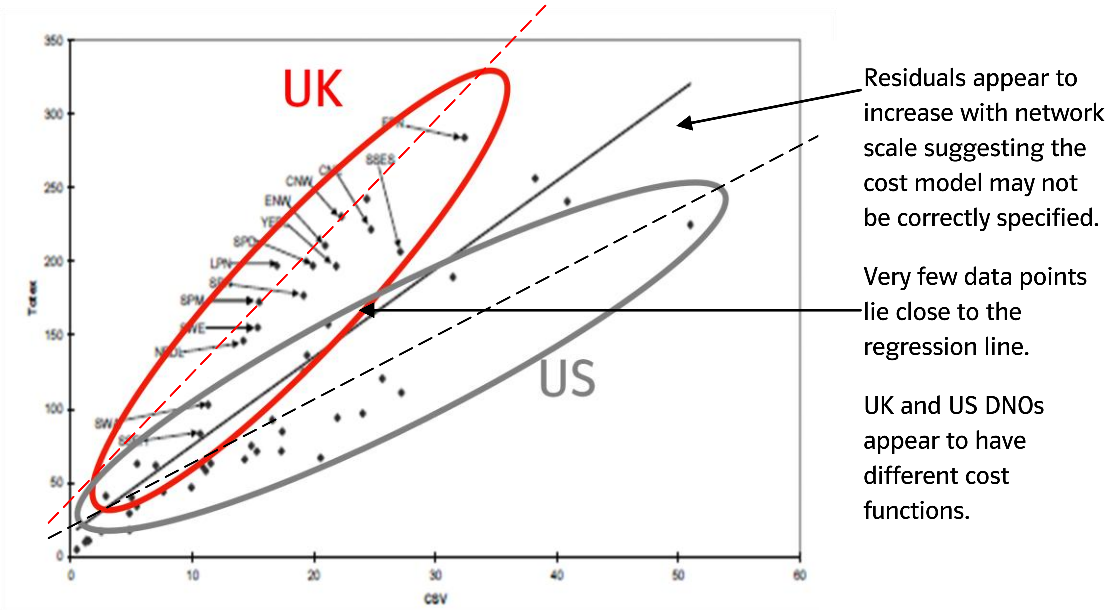
Mandatory pass-through cost adjustment. These costs correspond to the costs that are not under the control of the company (taxes and similar fees and transmission network access fee);

Different activity scope of responsibility (e.g. reading costs, metering costs, network losses compensation costs, public service obligation costs are not included in the scope of costs of all DNOs);

The adjustment of operating costs related to the differences of **Purchasing Power Parity** in different countries. It takes into account that the countries of the compared DNOs present important economic differences (for example, some of them are not in the eurozone).

While the study selects US DNOs in a similar climate to the UK this does not necessarily mean that the features affecting costs, such as consumption per consumer and consumers per km line are comparable with UK DNOs. US networks may be expected to have higher network length per customer than UK DNOs and also that energy consumption per customer would be expected to be greater. This may lead to US DNOs having larger CSV's than a comparable UK DNO which would in turn make them look more efficient.

A visual inspection of the results seems to suggest there may be different cost functions for the UK and US data with very few data points near the regression line itself and an apparent increase in the error term as scale increases. This suggests that the regression would not pass the statistical tests for heteroskedasticity or normal distribution of errors.



The results of previous analysis also makes it difficult to understand how there could be such a difference in productivity between UK and US DNOs.

Michael Pollitt's 1995 study *Ownership and Performance in Electric Utilities* compared 136 US and 9 UK distribution firms using 1990 data and finds that the relative performance of UK utilities is comparable to those of the US.

Then a more recent paper, *Electricity Distribution in the UK and Japan: a Comparative Efficiency Analysis 1985-1998*, suggests that the productivity gain in the UK electricity distribution has been larger than in the Japanese sector. In particular, productivity growth accelerated during the last years when the UK utilities were operating under tightened revenue caps. It also suggests that efficiency scores are higher for UK utilities.

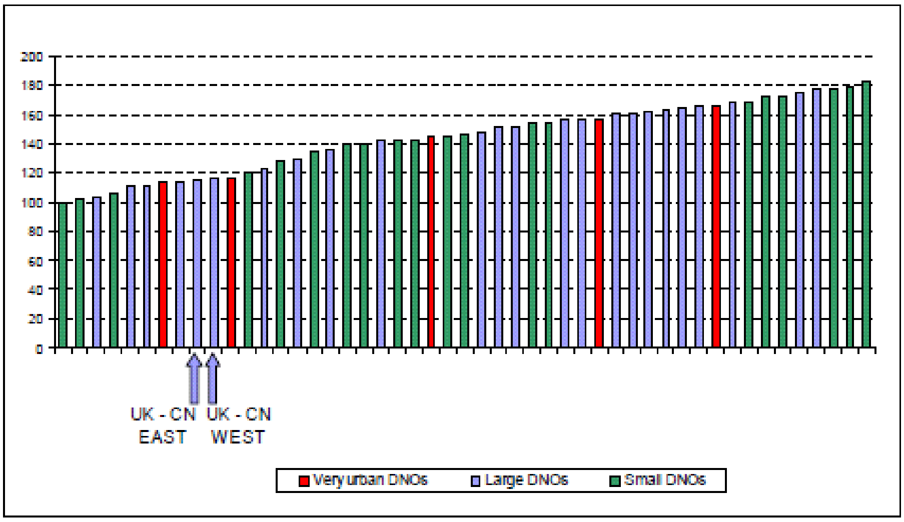
Having been in line with US DNOs in 1990 and then having made large and increasing productivity improvements in the late 1990s it is difficult to understand how UK DNOs could have then fallen so far behind the US DNOs which did not have the same pressure to increase productivity.

Our staff have visited networks businesses in the US which are part of the E.ON Group and have observed some significant differences in operation which reduce costs but are not transferable to the UK. For example, the network is composed of a far greater degree of overhead line, even in urban areas. Nearly all work is done live, including tree cutting which is not allowed under our UK engineering recommendations standards. In the US work is done dead by exception which is the opposite of our Electricity at Work Regulations. The US utilities also have much better land rights and have a high proportion of overhead lines located in the public verge which improves network access considerably. US utilities therefore are less constrained by the need to book outages or comply with NRSWA constraints allowing their resources to be used more flexibly and without the additional planning overheads required in the UK.

We believe that European DNOs may provide more relevant comparators with European networks being more similar in character to each other than US networks. Central Networks participated in a recent European benchmarking study carried out by Cap Gemini.

This analysis divided the DNOs by both scale and urbanity so as to ensure comparison between similar DNOs. This suggested that CN East and CN West ranked among the more efficient DNOs in Europe. Given that this uses 2006 where analysis suggests that Central Networks were relatively inefficient compared to other UK DNOs, it is logical to assume the other 5 UK DNO participants in the study would be at the forefront of efficiency within the 46 DNO European sample. Therefore we disagree with the assertion that there is significant scope for efficiency improvements by UK DNOs.

Figure 2.1: Internal Performance of each DNO on a Reference Network (basis 100 = best practice).(Includes Short-term Controllable Costs i.e. network operations and customer activities).[18]



Remarks concerning CENTRAL NETWORKS

CN East and CN West are at a similar level in their cost efficiency.

If all the DNOs in the sample operated the same average network, which would remove differences in the imposed and inevitable cost factors, CN East and CN West would be ranked respectively, 9th and 10th of the 46 DNOs which were compared in this study. Their performance on operating costs is 22% better than their peer group's (large DNOs) average. The two DNOs are part of the group of 25% of the best performing DNOs and in this group they are 3.5% above the average.

Question 2 When calculating these measures, what comparator sectors and time periods should we focus on?

The EU KLEMS dataset is widely recognised as a source of information on productivity. Although this dataset covers the period from 1970 to 2005 it is hard to relate productivity improvements achieved in the economic and technological environments of the 1970s and 1980s to any likelihood of potential productivity improvement in the very different industrial environment of the period from 2010 to 2015. The trend of productivity in the more recent period between 1990 and 2005 is more relevant to the DPCR5 period and Ofgem should focus on this time period.

For a productivity trend to be meaningful in an electricity distribution context the comparator sectors need to reflect aspects of the DNO businesses. Ofgem has highlighted seven sectors in the paper and of these three would appear to be out of place. It is hard to see how the manufacture of chemicals relates in any way to the construction and operation of electricity networks. The productivity improvements in manufacture of electrical equipment would seem to be reflected in the price that DNOs pay for plant and equipment. This appears in DNOs' costs. To apply the same productivity improvement to the installation and operation of equipment (as well as manufacture) would appear to be double counting. The sector of financial intermediation would appear to be a narrow sector with restricted relevance to DNO businesses. Broader categories which include a wider range of financial and business services, such as accounting, IT and insurance would appear to be more relevant as they would better reflect the indirect costs faced by DNOs.

Question 3 What weight should we give to this analysis relative to other information?

This analysis represents productivity improvements achieved in differing sectors of the economy. The sectors overlap with and are similar to some of the functions carried out by DNO businesses. Ofgem should use the conclusions drawn from this analysis to inform its view on the specific plans and efficiency forecasts presented by the companies. The companies' business plans will relate to the real and specific situation of the companies and consequently will have greater relevance to future efficiency achievements than historic sector wide average trends.

Question 4 What method should we use for setting our input price assumptions for DPCR5?

At the present time there are wide ranging views of how the economic recession will transition to recovery. Any input price assumptions require an anchor point around expected GDP and related price inflation. In the face of such extremes of opinion it would seem that the most credible approach for DNOs and Ofgem is to plan around a central case.

In many respects the CEPA forecast of input prices is similar to that of Central Networks. There is however a notable difference in terms of forecast labour rates. CEPA believe that labour costs will at best match average earnings growth through the DPCR5 period. We do not believe that this will be the case. The infrastructure sector is likely to be more resilient to the recession than other sectors of the economy. Those workers losing jobs in other sectors do not have the specialist infrastructure skills needed by DNOs, and consequently the bargaining power of workers in the infrastructure sector will not be reduced. Ofgem should recognise that DNOs will experience this premium to average earnings growth when setting input price assumptions.

Customers

Question 1 Do you agree with the proposed mechanism (in full) for worst served customers?

We welcome Ofgem's interest in making improvements for worst served customers, but we have concerns that the proposed mechanism will drive DNOs to only make improvements in localities where it is relatively easy to meet the ex-post funding assessment and therefore it will not provide benefits for those customers where network improvements are more costly and difficult to achieve.

Worst served customers generally live on spur lines at the ends of long circuits where all upstream faults lead to supply interruptions and improvements may require extensive network refurbishment or reconfiguration. As the cost benefit (under existing IIS incentives) of making improvements is generally high, DNOs have tended to place a lower priority on such work. It is for this reason that the network companies have sought an alternative mechanism to facilitate improvements for those customers that are truly worst served.

The proposed mechanism does however introduce a great deal of uncertainty as demonstrable improvements need to be evident before capex allowances can be claimed. This has the unintended potential to encourage investment in schemes where it is more certain that the required improvements can be achieved, and as such may lead to investments in the 'slightly poorly served but easy to make improvements customers' rather than those truly worst served. We therefore suggest that the degree of regulatory control over this relatively small investment of £600,000 per annum per DNO is somewhat excessive and may actually reduce its impact.

As this is the first time such investment 'allowances' have been provided then DPCR5 should be a period of trial and understanding. This will enable DNOs to assess different approaches and develop a better range of knowledge and experience to determine best practice. We therefore suggest that ex-ante allowances should be provided and DNOs be expected to demonstrate that investments have been targeted at worst served customers, with an aspiration to achieve 25% improvement, but without the absolute need to achieve this so as to not restrict the scope.

Question 2 Do you agree with the proposed approach (in full) for setting unplanned targets for customer interruptions and customer minutes lost?

Whilst the target setting process appears to grow in complexity we recognise that this reflects the efforts being made to incorporate the factors that can cost effectively be improved (response time and number of customers interrupted) and limit the influence of those factors that are difficult to influence without excessive investment programmes (such as underlying fault rates). We therefore believe that the process has delivered challenging but fair targets that drive DNOs towards benchmark performance.

We are however concerned that the absence of investment allowances and the general weakening of incentives could publically suggest that the industry and regulator do not see great value in further performance improvements.

Question 3   Do you think that we should set a cap on the cost per benefitting customer within the worst served customers mechanism and, if so, what level should this be set at?

The application of a cap would potentially limit the scope of works that could be undertaken; however it would be unreasonable to expect DNOs to spend the full allowance on one customer. A reasonable compromise would be to have a cap of £5,000 per customer that would lead to exclusion of extremely costly solutions but provide adequate scope for extensive works where this would provide an enduring improvement.

Network output measures

Question 1 *Is Ofgem's proposed methodology for general reinforcement and asset replacement outputs appropriate?*

We continue to support the aspiration to demonstrate the benefits from network investment through output measures. In general the proposed approach for general reinforcement and asset replacement where the output delivered is based upon the difference between a forecast position with and without investment appears workable.

We do, however, have significant concerns about the expectations that the links between outputs and investment levels will be adequately robust for inclusion in the June FBPQs, particularly as the decision trees and index bands continue to be developed.

In populating the proposed output indices, DNOs will make a number of assumptions that have the potential to be flawed. The companies should not therefore be adversely penalised for making best efforts to generate forecasts on load growth and asset degradation particularly where methodologies are new.

As is recognised in the Methodology Paper this is the first time that outputs will be used in a price control and therefore we would encourage Ofgem to consider allowing the flexibility for DNOs to revise output measures as negotiations continue through to final proposals in December and include a formal change process that operates during DPCR5 to revise targets in response to changing circumstances and improved data.

Question 2 *Is Ofgem's proposed approach for other areas of investment appropriate?*

DNOs have actively engaged in developing output measures for all investment areas and whilst investment values may not be significant the network impact does provide benefits for customers. The aspiration to create 'Tier 2' (non volume related measures) may not be appropriate for some of these investment areas and customers may be adequately satisfied in knowing that a number of sites have been improved (e.g. protected from flooding).

We support further work in this area during DPCR5.

Question 3 *What approach should be taken if a DNO fails to deliver the agreed outputs, i.e. how could the incentives be adjusted?*

As this is the first price control where DNOs are to agree to a set of outputs and particularly as the outputs are still under development, it does not seem appropriate to link failure of delivery with highly punitive consequences at this stage.

We suggest that a review of the outputs approach is considered in year 3 of DPCR5 where two years of data will enable a more informed view of the practicality and success of the outputs approach.

Question 4 Do you consider that the output incentives proposed provide sufficient protection in their own right, or is it appropriate to have some form of additional safety net in the DPCR5 settlement, for example through monitoring investment volumes?

We strongly believe that a 'safety net' based upon investment volumes is appropriate for both customers and DNOs. Incorrect assumptions within output forecasts could lead to either to significant excessive investment requirements to meet over-challenging outputs or more ready achievement with minimal network investment; with both potential outcomes would be protected by the safety net.

Question 5 Should there be an obligation on DNOs to further develop output measures during DPCR5?

In preparation for DPCR5, all DNOs have engaged with the process of developing outputs without the need for licence obligations.

Whilst an obligation could be used to encourage DNOs to continue to work on output development it would be inappropriate to introduce a licence condition for the production of 'Tier 2' outputs for all investment areas as these may be unnecessary.

Question 6 We seek views from stakeholders on the role that outputs should play in DPCR5 and particularly how they can best be implemented and used.

Network investment is carried out to maintain a safe and reliable electricity distribution system; keeping the lights on whilst preventing injury to staff and the public. The majority of investment is to prevent network failure whether from asset degradation, inability of equipment to carry the required demand, flood damage, interference, etc.

Outputs should demonstrate that DNOs are adequately and sustainably managing the asset bases to maintain a safe and reliable system. This means that where performance is deemed adequate then it should be maintained, but where it is deemed there is excessive risk the outputs should demonstrate that the risks have been reduced and controlled.

Cost incentives

Question 1 Do you agree with our proposed approach to equalising incentives?

Question 2 Have we identified the most appropriate costs to be within the equalised incentive and the IQI?

Question 3 How should we set the "RAV additions percentage" that will determine the split between "slow" and "fast" money?

The approach set out in the document should enable a more flexible approach to be taken to asset management and innovation by DNOs. At this stage it is hard to comment on any more than the principles. It would be of tremendous help if the mechanism could be illustrated in an appropriate spreadsheet model. We have some concerns about timing of cashflows and how any over or underspend is spread over the period. The mechanism should ensure that fast and slow revenues to DNOs from the mechanism are correct in terms of present value (i.e. if "fast" returns are spread over the period, or effectively logged up, they should be equivalent in present value terms to having be paid to the DNO in the year in which the expense was incurred.) Additionally, there is a potential link between spend profile and the impact of this mechanism, which a model would help to understand further.

Whilst we support the equalisation of incentives, we believe that this in no way reduces the need to ensure that benchmarking of costs takes into account any trade-offs. If anything, it will strengthen the need to ensure that adequate weighting is given to true 'top-down' and total cost benchmarks, as discussed elsewhere in this response.

We are disappointed that Ofgem has chosen not to explore our proposals for a modified IQI mechanism any further. We do not agree with the conclusions regarding complexity, and especially the conclusion Ofgem has reached that incentive strengths would have to be set on an ex-post basis. Our proposals would have significantly simplified the approach to managing uncertainty, whilst smoothing prices for customers and maintaining incentives for DNOs to manage risk efficiently. For example, the need for a separate real price mechanism, as Ofgem propose, would have been eliminated.

As Ofgem will be aware, we disagree with the assertion that cost variations close to the allowance will be most within the DNOs control. Small and medium-sized cost deviations from plan, to deliver a fixed set of outputs are most probable. Whilst some control may be possible for smaller variations, there is likely to be a "mid-range" band where a higher probability of variation, coupled with a lower degree of control exacerbates the impact of uncertainty in delivering a set of outputs.

Costs excluded from the IQI should include those not currently in DNOs plans, but that are required due to a change in policy at DPCR5 (for example, the costs of providing unmetered supplies to substations.) We would like to clarify with Ofgem, as a matter of some importance, the way in which IQI baselines will be set for non-capital expenditure. Ofgem has relied on backwards-looking benchmarks to calculate opex allowances to date. Applying this approach to the "total-cost" IQI mechanism, as set out in the paper, would mean that an incentive rate is set which does not take into account forward looking efficiencies. We have already outlined how we believe our plans are extremely stretching and ambitious, and that forward-looking benchmarking shows our plan operating cost efficiency to be amongst the lowest in the industry. The IQI mechanism was intended to provide an incentive for companies not to overbid and reward those companies who submitted and delivered ambitious plans. It is important therefore that allowances based on predominantly historical factors are corrected for the effect of future activity such that they are consistent with DNOs' submissions, before being used to set an incentive rate.

This is especially important given that the gas IQI matrix contains smaller additional payments than the DPCR4 approach. We do not believe that smaller payments are appropriate than those in the DPCR4 matrix. This is because, as Ofgem has acknowledged, the uncertainty facing DNOs is greater, and therefore there is a higher probability of divergence between DNO and Ofgem forecasts, as set out in CEPA's paper for Central Networks. If this regulatory risk is not acknowledged here then it should be accounted for in the cost of capital.

We support the approach of broadly leaving the overall regulatory capitalisation rate unchanged .We agree that financeability is an important consideration and that there is a link between the issue of depreciation lifetimes and capitalisation rates. Contrary to Ofgem's view, changing regulatory asset lifetimes can add to regulatory uncertainty, simply because the concept is a very strong regulatory lever that impacts cashflow and financeability of the business. Consequently, we are reassured of Ofgem's intention not to change this parameter.

RAV application issues

Question 1 *Views are invited on the approach to RAV additions and the range of costs to be capitalised.*

The paper considers the possible different treatments of ongoing pension costs and deficit repair costs, and we agree that it is appropriate to do so. For ongoing pension costs to follow employment costs for individual building blocks into the RAV is appropriate as it most closely resemblance the nature of that cost as a current and future cost of delivering that activity.

It is appropriate to treat the cost of deficit repair differently, as this cost is mainly driven by the historic and current circumstances affecting the scheme. A 'pay as you go' basis is therefore most appropriate, given these factors and the need to ensure financeability of DNOs. Due to the significant level of external influences affecting pension costs, these costs could be significant for DPCR5 and it will be important to ensure DNOs have sufficient access to finance to meet their obligations.

The proposed treatment of pension administration costs for DPCR5 and DPCR4 is balanced and appropriate.

Question 2 (captive insurers) *Views are invited on which approach to these costs is equitable over the long term as between DNOs and consumers and should be adopted?*

The methodology paper discusses three options Ofgem can consider in their approach to captive insurers. We still believe that the third option, to exclude captives from the related party margin rules, is the most appropriate solution. Captive insurers are inherently designed as a mechanism to efficiently manage risk for companies. The current process is not able to accurately calculate an appropriate margin for captives that serve more than just a single DNO, and therefore isn't capable of an equitable approach for DNOs and customers. By taking the third approach Ofgem could demonstrate that where appropriate, the price control can increase simplicity where real commercial drivers are present.

Managing uncertainty

Question 1 What balance should we adopt between mechanisms to manage specific risks (such as input price uncertainty) and a more general type of reopener to manage a wider basket of risks?

Question 2 What risks should be covered by a specific mitigation mechanism, by a general type of reopener, and what should be left to the DNOs to manage?

Question 3 Are there any additional risk mitigation mechanisms that we should be considering that are not identified in this chapter?

Ofgem correctly identifies a number of areas, including measures to reduce CO_2 and changes in input costs, which introduce uncertainty into the price control. We believe that cumulatively these factors represent a greater level of uncertainty in DPCR5 than in DPCR4.

Triggers are best suited to clearly separable risks which are material in scale and largely or wholly beyond the control of DNOs.

Trigger mechanisms need to be based on accurate and reliable measurements of quantities that reflect costs incurred by DNOs. They should be transparent in operation so that all stakeholders recognise the operation of the trigger and the impact of consequent changes, such as volatility of allowed revenues. Complexity of mechanisms and volatility of outputs undermine confidence in the regulatory regime. Having given the matter further consideration, we do not believe it is possible to create reliable and transparent mechanisms for demand-related expenditure or real price effects, and that a multiple "logging up" of costs could result in cash-flow issues, and adversely impact perceptions of regulatory risk. Given the developmental nature of the output regime, it would be more rational to develop a pre-agreed and clearly specified process to review the reliability and continued appropriateness of output measures either annually or mid-period.

A general reopener similar to the IDOK mechanism used by Ofwat may have some merit in terms of capturing unforeseen and unknowable events. Nonetheless, however, issues of separability, measurement and materiality thresholds remain. The mechanism would need to be tightly specified, and would be best referenced to a specific issue – e.g. a significant change in energy policy leading to the need to review DPCR5 plans. Too open a mechanism could again increase the perceived risk of the regulatory regime and place upward pressure on the cost of capital.

On balance, therefore, our view is that most of the uncertainty faced in DPCR5 is best managed by setting an appropriate cost of capital. This places companies in a position to manage risk efficiently and effectively without exposing customers to unnecessarily volatile charges.

Risks best managed outside the cost of capital are pension costs and corporation tax costs. Pension costs are separable, largely obligatory due to statutory legacy and driven by increasing life expectancy and the performance of investment markets. An ex-post adjustment for efficiently incurred costs is an appropriate approach. Corporation tax levels are subject to change by the Government of the day and a trigger mechanism is appropriate. More detailed comments can be found in our response to Chapter 11.

Tax methodology

Effective tax treatments

The purpose of the treatment for taxation costs is to provide DNOs with an allowance for taxation costs that are efficiently and reasonably incurred. We believe that the approach of setting tax cost allowances on an ex-ante basis is appropriate in order to achieve this purpose; however there are some factors regarding the nature of taxation costs that need to be considered further within the allowances such that it provides a fair allowance for both DNOs and consumers.

These factors are:

- Influences outside of the control of DNOs exist that can have a significant effect on the taxation costs (both positive and negative), e.g. changes to the underlying corporation tax rate as seen during DPCR4
- Differences exist between DNOs, in terms of the type of expenditure incurred, and this should be reflected in the taxation allowance to ensure fair reward is given to individual DNOs. A lack of transparency is rarely an incentive to minimise costs over a period.

We summarise our proposed treatment of taxation for DPCR5 as follows (we have also answered the specific questions below):

Ex-ante allowance with ex-post gearing adjustment	Described above, we feel this approach acts as appropriate incentive and encourages sustainable financial structures.
Allowances modelled using DNO specific capital allowances	A specific approach best reflects the different types of expenditure incurred by DNOs and thus provides a fairer allowance to DNOs more reflective of their actual tax costs. We recognise and support the steps taken thus far by Ofgem in moving from a generic to common approach.
Simple tax trigger mechanism to deal with significant events outside of DNO control	We have not historically supported a mechanism for ex-post adjustments for changes in the tax regime, as DNOs should be able to manage this risk themselves rather than pass it on to the customer. However current economic conditions have lead to an unprecedented amount of uncertainty within the price control, including taxation, and so we understand why

	it might be appropriate to include a trigger to protect customers and DNOs from the effects of change. Any such mechanism should be simple, to avoid unnecessary complexity within the price control, symmetric and have a materiality threshold that maintains the probable risk and rewards for DNOs to manage themselves.

Effective trigger mechanisms

We support the approach taken by Ofgem in their paper that a trigger mechanism should be symmetrical and measurable and 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 certain events outside of the control of the DNOs.

The proposed events to be included within the mechanism were too narrow and should be extended to include

- changes in, or clarifications to, HMRC interpretation of legislation, and
- new precedents set under case law.

The most significant event in recent years to affect DNO tax charges, the introduction of the Deferred Revenue Expenditure ('DRE') tax pool has never been legislated but represented an interpretation of case law (e.g. Tax Bulletin 53). This would not have been captured by the proposals included in Ofgem's paper.

The materiality threshold suggested of 0.5%-1.0% is a reasonable range to consider, and we would prefer a threshold at the lower end of the scale, but with risk/reward only for those amounts above or below the threshold.

Question 1 *Is the approach to modelling DNOs capital allowances on a common basis representative of the industry position and does it ensure that no individual DNO is materially advantaged or disadvantaged by this methodology?*

The approach we prefer for modelling DNOs capital allowances is to use a specific approach for each DNO as this best reflects the different types of expenditure, even within the broad categories (e.g. load, non-load) the different DNOs may incur and also the agreed treatment a DNO has on similar previous spend in its submitted tax computations.

If a common approach is to be followed, it is important that this is a true aggregation of all the DNOs positions and has not been moderated by Ofgem views. The percentage allocations to capital allowance pools submitted by DNOs in the FBPQ tables reflect the treatment in submitted computations and therefore we feel that it is not appropriate to adjust these to a position which does not reflect reality. In addition, given the many different types of spend within a category (e.g. Network operating costs) we feel that it is not appropriate to apply "broad brush" allocations to whole categories of spend (as shown in Table 11.1 of Appendix 14 – Taxation methodology statement) but individual line items (as detailed in the FBPQ tables) should each be separately considered.

Question 2 Views are invited on whether the most appropriate option for the tax treatment of re-openers is the case-by-case approach.

We think that the most practical approach to the tax trigger mechanism is to have an annual review of the financial model for any tax impacts, which is reflected in the tariffs for the subsequent regulatory financial year. It is most appropriate, where practical, for revenues to be adjusted within the price control that events occur, such that the right customers receive the any benefit or cost and that DNOs can finance their business as events happen.

Question 3 Should the DNOs retain the risk and rewards for all amounts below/above the trigger threshold; or for the entire amount rather than the excess over the materiality trigger; and what should be the appropriate timing of adjusting DUoS revenues following both single and multiple trigger events?

As stated above, we support DNOs retaining the risk and reward for all amounts within the trigger thresholds and only the amounts in excess of the trigger should be adjusted for within revenues. This approach maintains the incentive of DNOs to manage costs within the boundaries of reasonable risk.

We believe that the purpose of the trigger is to manage excessive risk and reward for customers and DNOs, for changes in tax costs outside of the control of DNOs. It is appropriate to ensure that the tax allowances adhere to the principles of other areas of the price control and that DNOs are incentivised to manage costs efficiently.

We stated in response to question 2 that an annual review would be most appropriate to recognise events that affect the trigger mechanism, with revenues adjusted annually. Where multiple events occur then the revenues would be adjusted on multiple occasions within the price control. The likelihood of such events happening is low and is only likely to happen if there was unprecedented volatility with tax legislation or government policy, when it would be appropriate for a trigger mechanism to take effect.

Question 4 We invite views on the practicality of communicating the likelihood of a trigger being activated and the methodology for it.

Any communication to stakeholders should aim to be informative and clear. Information provided on an ad-hoc basis to customers and suppliers could be unhelpful if it does not provide greater clarity and certainty on the effect of tariffs.

We believe the most practical approach of communicating a trigger event to Ofgem would be in writing within 30 days of the event occurring (e.g. date of enactment of legislation, date of issue of HMRC tax bulletin, date of decision in legal case where there is no leave to appeal).

If a trigger, or several triggers, in a year are material all adjustments should be made within 60 days of the end of the regulatory year by adjusting the model as appropriate

We therefore suggest:

- An annual re-run of the financial model, as suggested above, would provide the opportunity to assess whether a trigger event is within the materiality thresholds.

- That any communication to other stakeholders is done as an annual process at a point in time when clarity can be delivered. It should be combined with any other communication necessary as part of changes to the expected price control revenues.