EDF Energy response to Ofgem's DPCR5 Initial Proposals documents:

92/09 Initial Proposals

93/09 Incentives and obligations

94/09 Allowed Revenue – Cost Assessment

94a/09 Allowed Revenue – Cost Assessment – Appendices

95/09 Allowed Revenue and Financial Issues

1. Overview of EDF Energy response to the Initial Proposals

1.1. Introduction

We believe that, even though Ofgem suggests otherwise within the document, the Initial Proposals should be regarded as work-in-progress. There are a number of material errors within the proposals (we have already notified Ofgem's team of these), as well as many areas where Ofgem has asserted the potential for cost reductions or incentive targets without having given robust evidence that they can be achieved.

Combined with Ofgem's delay in making proposals on pension costs and the lack of discussion on ranges for the cost of capital, it is not possible for us to assess the proposals as a complete package. However, it is already clear that much more work is needed before the current proposals could be acceptable to us. The areas in need of improvement are set out in this response.

1.2. Positive developments

We are pleased that Ofgem has accepted our evidence on a range of important subjects, including the treatment of regional and urbanity costs within operating cost benchmarking and the equalisation of incentives.

We also believe that Ofgem's proposals for a Low Carbon Networks Fund are useful. Taken together with the existing and continuing Innovation Funding Incentive, Ofgem has created a useful starting point to discuss how the distribution sector can deploy innovative technical and commercial arrangements that can help the UK achieve its longer-term energy policy targets for the benefit of future consumers. We look forward in due course to bringing forward projects that will contribute to the low carbon agenda.

We are also pleased to see additional funding being allowed for investment in skills. The expansion of training helps ensure that the sector can continue to deliver vital services to consumers.

1.3. Non-transparent judgements

We are concerned that the Initial Proposals set out a variety of non-transparent judgments which, as a result, appear to us to damage incentives. DNOs cannot be expected to act efficiently if they cannot see what kind of expenditure will be disallowed and why. Ofgem indicates in a number of places throughout the proposals that it has selected answers from a range of analytical techniques on the basis of which answer aligns with its existing "impression".

We fear that Ofgem's approach creates a general disincentive to spend money, which may have been appropriate ten years ago, when the focus was on driving down operating expenses. However, as the RPI-X@20 process acknowledges, the focus of regulation has changed towards encouraging investment, which requires greater transparency of regulation.

Many of Ofgem's proposals even seem to use methods selected specifically in order to support its prior expectations of what its analysis should conclude or demonstrate. For instance, with respect to benchmarking methodologies, Ofgem itself has noted that:

> "The results for the top down analysis are very different to the results of the single group and groups analysis. Our view is that the results for single group and groups are **more in line with our expectation** of the results **given our knowledge of the DNOs**"
>
> Our view is that the top down approach combines costs to a degree that relatively simple cost driver models are unable to identify and differentiate between the differing circumstances of the DNOs…We have therefore used the single group and groups levels of disaggregation for our benchmarking results **but have considered the impact on the results of changes in drivers** and cost base at a top down level when determining our view of the comparative efficiency scores."

We believe that this approach means that Ofgem has in effect set allowances without reference to actual costs.

The next few months provide a short space of time for Ofgem to remedy the deficiencies of the Initial Proposals and to adopt more transparent approach. Addressing the matters set out in this response will take Ofgem much closer to an acceptable set of proposals.

1.4. Ofgem's "impression" of EDF Energy is wrong

There are a number of factors we can point to which undermines Ofgem's impression that EDF Energy is a high cost DNO:

- EDF Energy has consistently lower quartile DUoS charges
- After adjustments are made to ensure data comparability, EDF Energy's costs compare favourably to those of the other DNOs – the main ones being:
    - The balance between modelled unit costs and non-modelled costs
    - Regional and urbanity costs for some classes of capex work
    - Scope of load related work (per MVA of capacity added)
    - Transparency of indirect costs closely associated with capex (including treatment of Alliance Contractors).

These, and other relevant issues are addressed in detail in this response.

1.5. Risk/reward balance

Ofgem asks for views on whether the price control should be calibrated so as to:

a) "award the DNOs a cost of capital at the lower end of our range, but provide them with significant opportunities to outperform and more protection against underperformance"; or

b) "award the DNOs a cost of capital at the higher end of the range but where there are less opportunities to outperform and less protection against underperformance".

Although the price control contains a range of incentive mechanism, the ones that can have a material impact of Return on Regulated Equity are limited to just three:

- Costs (opex and capex combined)
- Quality of supply (CIs and CMLs)
- Losses

In all of these areas, our modelling shows that the Initial Proposals provide substantial downside risk for EDF Energy:

- Costs: unachievable cost levels resulting from the misspecification of allowances (described extensively in this response);
- CMLs: significant improvements to CML performance required to achieve the (agreed) targets for EPN and SPN (little or no outperformance opportunity on CIs and LPN CMLs);
- Losses: Significant downside (and largely uncontrollable) risk of unachievable targets for EPN with losses returning towards long-run average (little outperformance opportunity for LPN and SPN).

Overall, the incentive package is downside weighted with the result that without change EDF Energy will not be able to earn a return sufficient to finance its activities.

With regard to providing downside protection for the cost incentive, the solution must be to get the allowances right in the first place. Other mechanisms, such as adjusting the incentive rate will not be satisfactory since it will still leave us short of cash within the period.

We are not objecting to the CML targets as we know that we must improve our performance in this area.

On losses, the targets should be set to reflect what is achievable, and not by reference to recent history. Caps and collars should also reflect what is reasonably achievable though data management activity (which should be around 0.25% of units distributed compared to the 0.5% proposed). We have also suggested tighter

caps on upside for EDF Energy to assuage any fears Ofgem may have of windfall gains for our DNOs during DPCR5.

1.6. Assessing Ofgem's risk/reward options

Given that two of our three sources of downside risk for EDF Energy result from Ofgem proposing unachievable targets (cost and losses) neither of Ofgem's options is relevant.

Once Ofgem has set achievable targets (for cost and losses) the cost of capital should be set in relation to the riskiness of the resulting package. In our view, this corrected package will still contain little upside potential (the corrections having just removed deadweight downside regulatory risk). However, we believe that we will be able to manage our costs at the efficient level and will be able to to correct our CML performance over the coming years.

In this context we have a clear preference for Ofgem's option b) above:

> **"award the DNOs a cost of capital at the higher end of the range but where there are less opportunities to outperform and less protection against underperformance".**

1.7. Calibrating incentives

We do not believe it is appropriate for Ofgem to say "Should we be put under pressure to increase our view of baseline expenditure in the run up to the Final Proposals, we may have to consider the calibration of incentives and other mechanism to ensure that we have not made it too easy for DNOs to earn in excess of the baseline rate of return".

It is essential to get the cost allowances right. Evidence that cost allowances (baseline expenditure) should be higher than at present provides no grounds for tightening incentive targets. Such a response would be unreasonable.

1.8. Consistency with Authority's financing duty

We believe it can be questioned whether the Initials Proposals would be consistent with the Authority's duty to ensure that companies can finance their functions. There are a number of examples we can point to in the proposals, but perhaps the clearest are:

- **Capex unit costs:** use of an asymmetric approach (DNO estimate or median, whichever is the lower) with little attempt to adjust for scope boundaries will systematically deny the recovery of efficient costs
- **Cost benchmarking:** Ofgem has, on average, disallowed ten percent of the DNO's forecast costs – implying that overall Ofgem believes the sector to be inefficient – and yet Ofgem has carried out no cross-sectoral analysis to demonstrate this.

Indeed, Ofgem openly states that the proposals mean that "the baseline return for most companies will be below the assumed rate of return in WACC and they will need to make real improvements if they are to deliver assumed returns to their shareholders". Given that Ofgem has not demonstrated that the sector is inefficient, we do not see how this statement can be consistent with the financing duty.

1.9. Balance of the package

There is an inconsistency between Ofgem's repeated assertion that there is potential for efficiency savings and the emerging need to equip the companies to adapt their networks to meet the challenges of a low carbon future. It is not possible to reduce overall costs at a time when policy makers want to increase the outputs and obligations of the DNOs.

We recognise the continuing need for strong incentives to maintain pressure on efficiency. However, Ofgem should not to assume that DNOs can continue to out-perform the rest of the UK economy by achieving real unit operating cost reductions. The DNOs were unable to achieve Ofgem's DPCR4 efficiency assumption despite being exposed to an incentive rate of 100% on operating costs. Ofgem, therefore, has no grounds now for believing that exceptional savings can be obtained in the next regulatory period.

1.10. Review Process

There are areas in the Initial Proposals where explanations are inadequate or where statements do not stand up to scrutiny. There are several important areas outstanding (cost allowances, pensions, and cost of capital) and few, if any, areas that can be closed out at this stage. It is essential that Ofgem maintains a dialogue with DNOs right through to the Final Proposals.

1.11. Conclusion

There is clearly much work to do to develop an acceptable set of Final Proposals. We are committed to assisting Ofgem achieve this in whatever way we can.

2. Actions needed to correct the Initial Proposals

In this response, we set out clearly the actions Ofgem need take to rectify the Initial Proposals with regard to cost allowances and incentives. In summary, these are:

Capex related indirect costs	• Ofgem should include further indirect costs revealed by DNOs in its recent data request. We hope that this means that an adjustment for "recognition of indirect costs" will no longer be necessary • Ofgem should exclude non-recurring start-up costs from the benchmarking as they distort the efficiency scores • Capex benchmarking should exclude costs relating to large complex schemes (since their outputs are not included in current drivers) • Ofgem should consider including indirect costs in any special arrangements for high value projects • Use of MEAV as a driver of indirect costs will disadvantage companies with relatively large capex programmes. Ofgem should use total gross capex as the driver for indirect costs closely related to capex	Section 4
High value projects	• We believe that LPN is more affected by this issue than any other DNO • Ofgem should ex ante allow full funding of high value projects with ex post adjustment – this would help overcome issues relating to "median" unit costs etc. • Closely associated indirect costs should be included in any such mechanisms	Section 5

Capex unit costs	• Ofgem must use an unbiased estimate of unit costs – an asymmetric approach leads to the systematic under-recover of efficient costs • Ofgem must ensure comparability between DNO non-modelled costs • Ofgem must apply regional cost and urbanity factors to network investment costs (as it does for operating costs) • Where capex costs have been market-tested, Ofgem should demonstrate how further savings can be made or else allow the DNOs' forecast costs in full	Section 6
Other cost assessment issues	• Ofgem should recognise the weakness of the existing benchmarking models and adopt an average cost frontier for all the benchmarking models • IT and Property costs should be excluded from the benchmarking in line with Ofgem's own policy • The proportion of non-operational capex transferred to the Networks Investment Team needs to be included in capex allowances • Workforce renewal costs in DPCR4 should be treated as non-recurring and excluded from the benchmarking – otherwise first-movers like EDF Energy will be unfairly disadvantaged • Allowances for Traffic Management Act costs should be included where there is reasonable certainty that a particular permit scheme will be implemented • Data management costs should be excluded from the benchmark as this unfairly penalises DNOs who responded to the DPCR4 losses incentive	Section 7
Other network investment issues	• Our relatively high cost per MVA is justified on the basis of the greater volume of work involved – Ofgem should allow unit costs	Section 8

	which match the scope of work	
Relative price effects and frontier shift	• Ofgem must recognise different RPEs for contractor and internal DNO labour • Ofgem's stated policy is to apply a 1% p.a. efficiency assumption to network investment costs – but has in fact applied adjustments equivalent to 2.1% p.a. to EDF Energy. This must be corrected • Any double count between efficiencies already included by a DNO in its FBPQ forecasts and that assumed by Ofgem must be removed from Ofgem's analysis	Section 9
Losses incentive	• The incentive must be based on the later of RF or DF data as this is the most complete and accurate • The evidence set out in this response points to an incentive rate of £55/MWh (not the £60/MWh proposed by Ofgem) • Losses targets must be achievable, and in particular recognise underlying trends in settlements. DNOs should not be penalised for Ofgem's forecasting errors • Caps and collars should approximate to what is achievable with data management activity (+/- 0.25% of units distributed). Upside caps could be tighter where targets are adjusted to reflect underlying trends (i.e. EPN) • The operation of the DPCR4 losses roller should be clarified	Section 10
Connections	• We cannot accept a standard that we are likely to fail (particularly in relation to UMC faults) – the proposed "90%" licence condition must be withdrawn, postponed, or recalibrated. Ofgem should rely on the cost incentive properties of the proposed new GSoPs.	Section 12

Cost of capital	• Ofgem's Initial Proposals increase risk (particularly regulatory risk), potentially increasing the cost of capital • Ofgem must recognise the "new-normal" market conditions – and not assume a return to "bubble" conditions • There is evidence that the cost of equity has increased – Ofgem should give increased weight to surveys of investor sentiment and to forward looking models like the Dividend Growth Model. • Financial ratio tests should be on the basis of real cash flows not hypothetical and unachievable ones • The cost of debt must reflect the spread between different default risks	Section 15
Excluded Services	• The effective cap on metering activity at the forecast level is inappropriate and must be removed	Section 17
Pensions costs	• Ofgem has no new evidence to justify departing from the DPCR4 cost pass-through approach agreed at DPCR4	See separate response

3. Initial Proposals and increased risk

3.1. Risk and the cost of capital

We note Ofgem's view that the cost of capital needs to be set by reference to the riskiness of the DPCR5 package. This section of our response attempts to assess whether or not risk has increased or decreased compared to DPCR4.

Ofgem should be aware that the Initial Proposals contain two types of risk for EDF Energy, one a valid business risk, the other not;

- Valid: the operational risk of adverse outcomes in incentive schemes (i.e. the consequences of not delivering something which customers value);
- Invalid: the regulatory risks arising from unjustified and opaque disallowance of efficient costs

We regard the former as a valuable addition to our incentives, but the latter serves no purpose and should be eliminated from the Final Proposals once Ofgem has reviewed the further evidence and arguments we are submitting.

3.2. Cost of capital/allowance trade-offs

The use of an opaque and arbitrary regulatory process increases uncertainty.

Evidence of such an opaque approach to the Initial Proposals is prominent in the document. Perhaps it is most clearly illustrated by the following statement (para 3.28):

> "Overall we consider that the efficiency ranking generated by our work matches the impression that we and the companies have of efficiency in the industry. We note that the more efficient companies from our analysis were also forecasting lower network investment unit costs for the DPCR5 period".

Ofgem's "impressions" are opaque and, for that very reason, impossible to challenge. Such "impressions" are entirely subjective and should have no part in the review and no part in utility regulation more generally. Instead, Ofgem should set out what its analysis says in a transparent and objective way, in order to provide proper scope for external review and discussion.

An example of the difficulties reliance on "impressions" can lead to is that Ofgem has not yet resolved scope boundary issues between unit costs, and between unit costs and non-modelled cost, and cannot, therefore, be in a position to know whether our unit costs are excessive. In fact, as we demonstrate in this response our unit costs are relatively high because we have include a larger scope of work in the modelled costs than those used for the benchmark. Clearly, impressions are no substitute for analysis.

Another example concerns the treatment of alliance contractors in the cost benchmarking, where the results for indirect costs move by £80m to £90m depending on how much Ofgem excludes from the analysis because of differences in cost transparency between the DNOs. The outcome of this one difficult issue should have a big impact on Ofgem's impression of EDF Energy – but of course, those impressions may influence the decision!

The long-term result of Ofgem's current approach will simply be the destruction of the appetite to invest, except where expected returns are particularly high. Efficient, but marginal investments will face too much risk of future disallowance. Customers will be the eventual losers from such an approach.

3.3. Riskiness of the Initial Proposals package

The table below sets out the main risks to which EDF Energy would be exposed if the Initial Proposals be implemented.

They are a mixture of valid and invalid risks (described above).

Risk	DPCR4	DPCR5	Increase/decrease in risk to EDF ENERGY
kWh volume reduction	Volume driver 50% units/50% customer numbers	No volume driver	Increase? Revenue no longer tracks costs (apart from unspecified re-opener for general reinforcement expenditure)
Capex overspend	29% - 40% sharing factor on net costs	39% - 45% sharing factor on net costs	Increased – sharing factor reduces risk – but non-transparent methods used to set allowance increases risks

Network outputs not achieved	Ex post assessment of outputs at DPCR5 for under-spending DNOs	Output measures partially developed – no clear rules on use at DPCR6– mechanism for change to targets within period not clear	Increase - additional regulatory risk, which discourages efficient investment that *might* be disallowed under future rules
High volume – low cost connections involving shared assets – cost not recovered	29% - 40% sharing factor on net costs	Volume drivers (with true up for proportion recovered through connection charges)	Unknown – volume drivers not specified
Opex overspend	100% exposure	100% exposure for Business costs. 39% - 45% for other costs	Increased – sharing factor reduces risk – but non-transparent methods (e.g. use of "impressions" used to set allowance increases risks
Losses incentive penalties	Uncapped – but targets based on ten year history	Cap/collar 0.5% units – but targets based on 5 year history	Increase – cap and collar reduce variability of profits – but approach to target setting increase risk of large penalties
TMA costs not recovered	Reopener	Reopener	No change
ESQCR costs not recovered	Reopener	n/a	n/a

DG Incentive penalties	Floor on rate of return	Floor on rate of return plus some minor changes to incentive rate	No change
Pensions costs not recovered	Ex post adjustment	Unknown	Probable increased – risk of adverse trustee reaction to uncertain cash flows
Quality of supply incentive penalties	Capped at +/- 3% revenue Exceptions of severe weather	Capped at +/- 3% revenue Exceptions of severe weather – but incentive rates increasing	Increase – incentive rates have increased
Connections GSoP payments/fines	Uncapped – but limited standards	Uncapped – significant increase in number of standards 90% licence threshold	Significant increase as Ofgem has no evidence that 90% threshold is achievable for the costs allowed
Customer service incentive penalties	Telephone survey – capped at +/- 0.25% revenue	Enlarge customer survey +/- 1% revenue from 2013	Significant increase
IFI/LCNF costs not recovered	Partial funding – but scheme limited in size	Greatly enlarged scheme – 90% funding Threat of disallowed cost of catch-up DPCR6 onwards	Significant increase as a result of DPCR6 funding threat

Rising and Lateral mains costs not recovered	29% - 40% sharing factor on net costs	39% - 45% sharing factor on net costs	Currently risky – outcome depends partly on Ofgem determination on current cases

3.4. Increased risk should be reflected in the cost of capital

It is difficult to make a link between the riskiness of the Initial Proposals and the cost of capital. One possible approach would be to assess the impact on revenues of each of the mechanisms described above and, hence, their impact on the return on equity. However, the summary above indicates that risk (both regulatory risk and incentive risk) has increased compared to DPCR4. On this basis, other things being equal, we believe that the cost of capital should rise.

3.5. Ofgem's modelling of returns is not convincing

The Initial Proposals set out some modelling Ofgem has carried out in this area (its Monte Carlo analysis). However, few details are provided and the results are difficult to interpret. Overall, the conclusions seem improbable. Ofgem states that:

> "At this stage, the work we have done in calibrating the incentives would mean that DNOs have an opportunity to earn a likely maximum of 57 basis points and face the risk of losing a maximum of 58 basis points from the incentive mechanisms alone."

Ofgem does not, however, say how likely it is that DNOs will achieve higher or lower returns, or what they would have to do to achieve the higher returns. Many of the targets set by Ofgem are already biased towards the challenging end of the scale. Ofgem's assumed opportunity to earn higher returns is of no relevance, if it is unattainable in practice.

For EDF Energy the Initial Proposals imply performance substantially below the assumed cost of capital – as a direct result of Ofgem proposing unachievable cost and losses targets. Elsewhere in this response we note that Ofgem should apply its financeabilty tests to realistic cash flows, not hypothetical cost levels which it knows are unachievable. The same is true of any calibration of betas in relation to the riskiness of the package on offer.

4. Capex related indirect costs

We are pleased that Ofgem has continued to include an adjustment in respect of "recognition of indirect costs" (i.e. indirect contractor costs such as those associated with Alliance Contracting which are transparent to Ofgem). However, we are very concerned that Ofgem has only included £11m out of a total of £33m for EDF Energy in this adjustment.

We regard it as a positive development that Ofgem has asked the DNOs to submit additional information on the extent to which contractors provide indirect activities as part of contracts primarily for work on the network. We hope that this will enable Ofgem to have comparable costs from the DNOs.

Ofgem need to be aware that this is a major issue for us which will have a pivotal bearing on the outcome of the review. We have calculated that if Ofgem made a full allowance for EDF Energy's contractor indirect costs, allowed costs would increase by around £85m.

4.1. Transparency of Alliance Contracting

We continue to maintain that our Alliance Contracting system provides an unmatched level of cost transparency to Ofgem, and that it would be perverse to penalise EDF Energy because of a failure to compare costs on a like for like basis.

In the May Methodology document, Ofgem's stance on the IDT contracts was:

> "In discussions with some of the DNOs we are persuaded that where 'open book' contracting relationships with contractors result in changes in reporting this should be taken into account as part of the comparative benchmarking. "

However, in the Initial Proposals Ofgem's position has now advanced:

> "We have asked the DNOs to submit additional information explaining the extent to which contractors undertake indirect activities as part of contracts for work primarily working on the network. At this point that data has not been provided but we will include the results of our analysis for the autumn update paper. Until this work is completed we have retained an adjustment for the alliance contracting for EDF Energy. However, the evidence we have been provided to date suggests that some other DNOs which insource more of their direct activities, may be disadvantaged by the adjustments we have made. We consider it likely therefore that the results in the Autumn update will be impacted by the outcome of our ongoing work in this regard."

This is clearly an important area where there are very different views across the DNO community.

As we have discussed above, Ofgem's treatment of these costs has a profound effect on the benchmarking and the resulting efficiency scores, as shown in the following

table. Adjusting for Alliance Contractors reduces the gap between costs and the benchmark by 12 percentage points for LPN and by 16 percentage points for EPN.

The table below shows the impact of different levels of adjustment:

	Costs relative to benchmark (%)		
	Initial Proposals	**75% IDT adjustment**	**Full IDT adjustment**
LPN	113	104	101
SPN	110	108	108
EPN	117	104	101

The table includes a comparison with a 75% adjustment for IDT, as this is the proportion of IDT costs that Ofgem excluded in 2007/08 costs. The effects on EDF Energy are still significant – 9 percentage points for LPN, 2 percentage points for SPN and thirteen percentage points for EPN.

It is curious that Ofgem's benchmarking analysis excludes 75% of the IDT costs for 2007/08, but only 33% of the IDT costs for 2008/09. These choices have a significant effect on EPN and to a lesser extent LPN. There is no discussion of why different figures are appropriate for different years. It has the effect (perhaps coincidental) that approximately the same amount in absolute terms is excluded in both years. We would be better able to comment on these proposals if Ofgem had explained the reasoning behind these choices. We hope that Ofgem will do so quickly.

The impacts on allowances are considerable. For example, a full IDT adjustment would improve EDF Energy's allowed costs by £80m to £90m. In particular, we note that the efficiency score affects not just capex-related indirect costs, but also IT, property and non-operational capex costs.

4.2. DNO FBPQ data not credible

We welcome Ofgem's recognition that as a DNO's capital programme grows its indirect costs must grow to support it. This was an issue we raised at DPCR4 and we are glad that the principle is now accepted. We are, however, concerned with Ofgem's view that indirect costs only grow in the ratio one percent for every three percent increase in direct capex. We understand that this ratio has been derived by looking at the historical expenditure and the DNO's FBPQ forecast. However, such an approach is only valid if the growth in indirect costs, associated with the growth in gross capex, is visible.

The tables below detail the absolute and percentage increases from the 2005/06 gross direct capex to the maximum expenditure in DPCR4 and the maximum in DPCR5 along with the corresponding movement in engineering indirects. This analysis is

based on the information published by Ofgem on each of the DNO's February 2009 FBPQs

Table 1: Direct capex analysis

Direct Capex (07/08 prices)	Increase 05/06 to DPCR4 max (£m)	Increase 05/06 to DPCR4 max	Increase(05/06 to DPCR5 max) £m	Increase(05/06 to DPCR5 max)
CN West	58.0	71%	118	144%
CN East	73.4	65%	144	127%
ENW	60.6	65%	108	116%
CE NEDL	11.6	15%	42	55%
CE YEDL	3.1	2%	45	35%
WPD Swales	14.8	34%	33	78%
WPD Swest	9.5	15%	44	67%
EDFE LPN	46.8	46%	160	158%
EDFE SPN	42.5	40%	82	77%
EDFE EPN	84.6	56%	137	90%
SP Dist	65.4	78%	134	160%
SP Manweb	53.7	62%	161	186%
SSE Hydro	23.0	58%	27	68%
SSE Southern	70.0	63%	74	67%

Table 2: Engineering indirect analysis

Engineering Indirects (07/08 prices)	Increase 05/06 to DPCR4 max (£m)	Increase 05/06 to DPCR4 max	Increase(05/06 to DPCR5 max) £m	Increase(05/06 to DPCR5 max)
CN West	11.0	43%	12	47%
CN East	0.0	0%	-4	-12%
ENW	0.6	2%	0	0%
CE NEDL	0.3	2%	0	3%
CE YEDL	0.5	2%	1	3%
WPD Swales	0.3	2%	2	14%

WPD Swest	0.0	0%	2	9%
EDFE LPN	11.9	71%	20	117%
EDFE SPN	10.1	63%	11	68%
EDFE EPN	19.7	76%	22	84%
SP Dist	0.0	0%	-1	-4%
SP Manweb	0.0	0%	0	-2%
SSE Hydro	2.0	14%	2	17%
SSE Southern	6.3	25%	7	28%

The data shows a significant divergence in results with some companies apparently able to deliver significant increases in gross direct capex, both in DPCR4 and forecast for DPCR5, with no increase in the associated support costs.

It is helpful that Ofgem has asked the DNOs to identity all of their indirect costs embedded within contractors' changes. Until this is done, it is impossible to draw any conclusions about the relative efficiency of EDF Energy's approach and cost levels.

4.3. Non-recurring (start-up) costs

Our Alliance Contractor costs included around £5m of non-recurring start-up costs in order to set up new processes, IT systems, training, team development etc.

For a fair benchmark calculation of efficiency an adjustment should be made (~£5m) to remove the set-up costs of the new system, as this expenditure represents a one-off investment, not a continuing supplement to "business as usual" operating costs.

4.4. Cost driver must reflect scale of capex programme

Ofgem has asked the DNOs to submit details of indirect costs embedded in contractors' costs. Hopefully this will provide comparable data which supports robust comparison. On this basis, an adjustment for cost reporting will no longer be necessary.

However, it will important to get the driver right. In particular, we have strong reservations about the use of MEAV as a driver of these costs.

The table below shows that there is wide variation between gross capex as a percentage of MEAV. It is the scle of the capex programme that drives the capex indirects – not the size of the network (MEAV). The size of the capex programme is itself driven by the condition and reinforcement needs of the network, not by its absolute size.

As we have said above, EDF Energy has a relatively large capex programme. Our programmes, together with SP were around 2% of MEAV in DPCR4, with the remaining DNOs between 1.3% and 1.6%. For DPCR5 we plan to spend 3% of MEAV (with only Scottish Power in excess of this with 3.3%) but with the other DNOs only investing between 1.8% and 2.6% of MEAV.

	DPCR4 average spend	DPCR5 average spend	MEAV (£m)	DPCR4 gross capex per MEAV	DPCR5 gross capex per MEAV	DNO DPCR4 gross capex spend at average level (£m)	Difference to actual (£m)
CN	270.4	428.8	16437.4	1.6%	2.6%	269.1	-1.3
ENW	129.8	196.9	7879.2	1.6%	2.5%	129.0	-0.8
CE	198.1	275.4	12625.7	1.6%	2.2%	206.7	8.6
WPD	120.7	179.2	9243.4	1.3%	1.9%	151.3	30.6
EDFE	439.7	695.6	23234.3	1.9%	3.0%	380.4	-59.3
SP	257.6	421.3	12787.9	2.0%	3.3%	209.4	-48.3
SSE	190.8	247.2	13767.0	1.4%	1.8%	225.4	34.6
Average				1.6%	2.5%		

Use of MEAV as a driver of indirect costs will discriminate against EDF Energy (and Scottish Power) in the cost benchmarking. Ofgem should total gross capex as the driver for indirect costs closely related to capex.

4.5. Recognition of indirect costs – complex schemes

Our discussions so far with Ofgem have focused on the costs associated with our Alliance Contracting approach. However, there is another, albeit small, element to our cost base that needs to be fully recognised by Ofgem. That is the costs of specialist services associated with a limited number of very large and complex engineering projects.

We do not believe that work of this type is adequately represented in the costs of the other DNOs (i.e. they are starting from a low cost base because they typically have

few large complex projects), and secondly, we do not believe that the drivers used in the indirect cost modelling are adequate to capture our circumstances. Ofgem's modelling of Group 1 costs used MEAV and Gross capex as drivers, and that of Group 2 costs used MEAV and total direct costs as drivers. None of these includes any measure of scheme complexity. This omission has the effect of discriminating in favour of DNOs with the fewest complex projects, and as a result inevitably discriminates most against LPN.

This is evidenced by Ofgem's regression analysis of Group 1 costs (Network Design, Project Management and System Mapping). The range of performance, compared to the average, runs from 52% for Scottish Hydro to 155% for LPN. This range of performance is not credible and indicates that there is an explanatory variable missing from the cost driver.

We describe the cost attributes of "scheme complexity" below. We ask that Ofgem removes £5.6m from the Group 1 benchmarked costs.

4.6. large LPN projects accounts for £5.6m of costs

Our 2008/09 contractor costs shows £37.5m of indirect costs. Of this:

- £21.6m related to alliance contractors; and
- £15.8m relates to other contract support

However, of the £15.8, some £5.6m relates to just six very large and very complex schemes:

- Lodge Road 66kV
- Bankside
- Hackney 132kV
- Brunswick
- Seacoal Lane

Ofgem will be familiar with these as they are reported as "top ten projects" in the annual RRPs

These schemes, by their very nature, need:

- More specialist input:
    - Architectural and civil works designs due to complexity of locations
    - Expert project management, safety, quantity surveying, senior authorised persons and other specialist engineers
    - Design and management effort resulting from subsurface EHV substation installations, cable tunnels with multiple access shafts, forced ventilation arrangements
    - Complex planning requests/consents, including conservation area aesthetics considerations
    - Managing archaeological surveys/constraints

- More project phases and temporary arrangements/stages resulting from space restrictions caused by no adjacent available land
- Restrictions of working in designated 'confined spaces' (tunnels, underground chambers etc.)
- Additional plant and materials storage - to overcome difficulties due to space constraints
- Dealing with neighbouring commercial interests and traffic flows sensitive to progress of works

The following sections set out the particular issues for the six large projects. They illustrate features of each project that inevitably raise its unit costs above those of a typical project, let alone any 'frontier' project. Below we summarise (a) the costs of the project (b) additional planning requirements and (c) difficult on-site working conditions.

Bankside

- Most complex project in LPN's portfolio, current estimated total project cost of £55m; Existing Bankside Power station building to be structurally re-enforced to accommodate new plant and building layout alterations.
- Very complex civil designs - in constant negotiation with Tate Gallery and London Development Authority
- Multi-phase project – decommissioning one 22kV substation two 11kV substations and creating two new 11kV substations with a total of 84 panel switchboard (we believe this is the longest switchboard in Europe) and one 20kV substation with 23 panel switchboard
- Temporary switchboards to be created; many work phases required to transfer distribution feeders to new switchboard
- Total build to be achieved in compressed timeframe – equivalent to two-and-a-half substations in 3.5 years when normal project duration for one substation is approximately five years

Seacoal lane

- Total Cost £30-40m, Network Design ~£3m, Arup~£1m for specialist civils design work
- Substation underground on three basement levels; ventilation issues; cable tunnels necessary for cable routes from site
- Restricted access to site; Old Bailey nearby (noise and traffic flow constraints etc.)
- Complex planning applications; proximity of Network Rail infrastructure; Fleet river runs underground adjacent to site
- Demolition of building above ground necessary; difficulties in negotiating with Land Securities adding to costs; land owner insists on restrictions in magnetic field densities (EMF Studies)

St John's Wood

- Site to be converted from existing leased operational site while maintaining continuity of supply; complex negotiations with landlord
- Installation of temporary switchboard necessary
- New entry into existing 'live' cable tunnel required
- No adjacent available land for plant and materials storage
- Many temporary stages required with very complex sequencing of work during project (circuit transfers/diversions/access to live compounds etc).
- Circuit availability extremely difficult due to high circuit loading leading to high proportion of out-of-hours work
- Road closures necessary (some only available at weekends)
- Complex cable design requiring specialist design consultants (£330k)
- Physical constraints in installation of larger XLPE cables in a smaller footprint whilst ensuring continuity of existing circuits. Many carriageway trial holes to lay new cables due to sub-surface congestion
- Construction issues: seismic disturbance vibration and risk of trip whilst working and excavating in vicinity of live cables - safety and operational issues
- Access issues: road closures; parking bay suspensions for delivery of plant and equipment; large cables drums and joint bays in roads
- Civil construction issue with respect to contaminated ground, local highway environmental noise restrictions; local authority working hour restrictions, tunnel construction; confined space working in tunnels
- Third party consent and negotiation issue with Metropolitan Police; residents; Lords Cricket ground events management; local authorities and NGC especially in Red Zone working
- Load at risk necessitates 24-7 working and greater additional labour costs plus additional project management on risk planning and contingency plans, safety planning and controls due to working at height and confined space

Lodge Road

- Total Project Cost to £22m; Network Design: £1.1m
- Site converted from existing operational site while maintaining supplies at all times
- Cable tunnels required
- No adjacent available land for plant and materials storage
- Many temporary stages required during project
- Existing building required re-design and alteration as not fit for new purposes, planning requirements for external appearance
- Interface with NGC required throughout
- Site security requirements to be accommodated
- Complex earthing design given proximity of NG site

- Design to accommodate four adjacent live substations and full segregation of operational works where possible
- Decommissioning design of redundant assets

Hackney 132kV GIS Substation

- Estimated total project cost of £13.4m
- Establishment of 132kV Grid Supply Point
- Project interrelated with Undergrounding of existing 132kV Tower line and the provision of new 132kV switchboard at Bow
- Project completion to align with Olympic site development works

Brunswick

- Brunswick – Osborn St Cable Tunnel
- £1.44m Design and Feasibility cost
- £1.4m Wayleaves and Consents cost
- £3.4m Project Management cost
- 24-hour working
- 8.3km Tunnel with seven Shafts plus Ventilation, Security and Communication Systems
- Permissions required to pass beneath Rotherhithe Tunnel, Blackwall Tunnel, DLR, PO Railway, Central and Metropolitan lines etc.
- Ground contamination issues

4.7. Future complex schemes

Of the 20 schemes over £15m in the EDF Energy footprint that will progress through the DPCR5 period 12 are in the LPN area projects. These projects are mainly associated with the construction of new 132/11kV substations and with deep cable tunnel and cable routes needed to interconnect them. Without exception, these 12 projects are all to be progressed within similar environments to the six major projects identified above. It is therefore not unreasonable to anticipate that during the DPCR5 period we will experience similar complexities in the design and delivery of these projects as we have during our major project work in DPCR4. These conditions are not comparable with those faced by network operators in other areas. As in DPCR4, during the DPCR5 period we will have to employ the services of specialist civil and electrical designers and consultants in order to ensure the delivery of these projects.

The high value schemes for DPCR5 are set out below. As can be seen, they are predominantly in the LPN footprint.

Scheme Name	DPCR4 £m					DPCR5 £m					DPCR4 £m	DPCR5 £m	DPCR6 £m	Total £m
	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15				
Construct Finsbury Mkt-Osborn St-Wellclose-Brunswick Wharf Cable Tunnel	0	0	0	0	6.7	14.4	21.3	15.7	4.1	0	6.7	55.5		62.2
London Gateway - Shell Haven - redevelopment (RDP)	0	0	0	0	1.7	6.9	6.9	6.9	6.9	6.9	1.7	34.5	5.2	41.4
Reinforcement of the Lawford/Rayleigh 132kV double Circuit (PNB, PUD,PAE)(RDP)	0	0	0	0	0	0	0	1.2	6.1	10.3	0	17.6	19	36.6
Great Eastern St: Establish new 2x30MVA 132/11kV Substation	0	0	0	0	0	0	0.6	4.4	10	9.5	0	24.5	5.5	30
Bankside: Substation modernisation	0	1.9	5.2	2	13.7	7.2	0	0	0	0	22.8	7.2	0	30
Parker Avenue 132/33kV Grid S/S - install grid transformers and 132kV circuits (2x90MV	0	0	0	1.3	1.2	0.9	1.7	4.1	5.3	6.7	2.5	18.7	5.3	26.5
Eaton Socon 132kV GSP - 3rd SGTand new 132kV GIS switchboard	0	0	0	0	0	0	0.4	2.7	5.3	5.3	0	13.7	8.4	22.1
PO Route Rebuild	0	0	0	0	0	0.6	2.7	4.2	4.2	4.7	0	16.4	4.6	21
Leadenhall: Establish new 2x66MVA 132/11kV substation	0	0	0	0	0	0	1	5	8.2	6.8	0	21	0	21
Rye House 132kV Grid S/S - Replace switchgear	0	0	0	0.3	2	7.8	6.4	4.3	0	0	2.3	18.5	0	20.8
Bressenden Place: New 3x66MVA Substation adjacent to Victoria Street SW1	0	0	0	0	0	0	0	0	3	6	0	9	11	20
Seacoal Lane: Establish new 132/11kV Substation	0	0.3	1	2.4	1.1	0.5	2.2	6.2	5	0.4	4.8	14.3		19.1
Finsbury Mkt-Brunswick Wharf Tunnel: Install 3x132kV ccts	0	0	0	0	0	0.9	7.1	6.6	3.6	0	0	18.2		18.2
Osborn St: Establish new Osborn Street 'B' 132/11kV Substation	0	0.4	-0.3	2.6	2.7	6.3	5.7	0.8	0	0	5.4	12.8		18.2
West Weybridge - Replace 132kV Switchgear	0	0	0	0.4	3.2	8.1	6	0	0	0	3.6	14.1	0	17.7
St Pancras: Substation asset replacement and uprating	0	0	0	0	0	1.5	6.2	5.1	1.9	1.4	0	16.1	0	16.1
Proposed Marston 132/33kV Grid S/S - 2 x 90MVA	0	0.1	0.5	3	1.8	3.1	4.1	3.4	0	0	5.4	10.6	0	16
Establish new Greenwich Peninsula 132/11kV MSS	0	0	0	0	0	0	3	8	5	0	0	16	0	16
North Quay: Establish 2x66MVA 132/11kV substation	0	0	0	0	0	0	0	2	7.5	5	0	14.5	1.5	16
Wood Wharf: new 2x66MVA 132/11kV substation	0	0	0	0	0	0	0	0	1.5	5	0	6.5	9.5	16
										Total	55.2	359.7	70	

Key:	EPN	SPN	LPN

4.8. Indirect costs for complex schemes - solutions

We are happy to provide further details of the complexity associated with large EHV schemes. However, we believe that EDF Energy, and LPN in particular, incurs a disproportionately large proportion of costs on such schemes and that currently these costs are not adequately represented by the benchmarking cost drivers. We do not believe that these projects can be delivered at unit costs below our forecast levels.

Ofgem can solve the problem of understating unit costs either by improving the cost drivers (which is difficult to do robustly) or (our recommended approach) by taking the associated costs out of the benchmarking altogether. The latter approach will remove costs that do not correspond to the chosen measures of output and which should not therefore, be included in the comparison.

Ofgem has already proposed mechanisms for dealing with the direct cost elements of high value projects (we discuss this below). It would also seem sensible to include the relevant indirect costs within such mechanisms.

5. High value projects

We understand from our meeting with Ofgem on 4th September 2009, that, of the three options put forward in the Initial Proposals for treatment of 'high value projects' (Cost Assessment paper paras3.90–3.93), Ofgem has now provisionally discounted the first of these, which was to provide an ex ante allowance and conduct an ex post review. The two remaining options for consideration are therefore:

- (Option 1) ex ante allowance with outputs and re-opener (generally for projects expected to complete within period); and
- (Option 2) partial ex-ante allowance with phased outputs (generally for projects starting later in the period (and/or transcending periods) or where the final solution and costs have yet to be fully developed).

Following useful discussion at the above-mentioned bilateral meeting, we believe that either (or both) of these options are workable, subject to the following provisions:

- 'Outputs' in this context would not generally be typical of the output measures included in the Output Measure framework but might, instead, be agreed project milestones relating to phased completion stages (i.e. Tier 3 type measures because Tier 2 type output Load Index or Health Index measures would generally be delivered only following project completion);
- The outputs (achievement stages) to be based on the project plan milestones factored into our overall submission;
- The ex ante allowance to be based on costs which are symmetrical in terms of risk of over-expenditure and opportunity for out-performance. In this respect we believe that the 'target price' agreed with our Alliance Contractors would be the logical basis for the ex ante allowance, given that this is set at a level which rewards only genuine efficiency gains (and penalises inefficient cost overruns) on a 'gain/pain share' basis;
- "Partial" allowance should cover the costs, to avoid cash-flow issues and ensure that financeability is maintained;
- Incorporation of specified, reasonably prudent, risk mitigation and contingency provisions included in the overall project schedule of costs (recognising that the urbanity and complexity factors which tend to drive higher than average cost projects are also, by their nature, often difficult to accurately forecast and quantify);
- Given that the urbanity and complexity factors are also responsible for higher than normal indirect costs associated with the overall end-to-end management of the project, these costs also to be included in the arrangements for treatment of high value projects. This would also

beneficially resolve the issue surrounding the disproportionate impact of high value project indirect costs on benchmarking, and thereby enable the residual indirect costs (associated with routine projects) to be benchmarked more meaningfully;

- Except where (for projects treated under option 1 above) there is sufficient certainty regarding outturn costs, the overall aggregated costs of high value projects to be excluded from the IQI allowance, but the IQI incentive (sharing factor) to be retained (i.e. the IQI incentive derived from our overall submission excluding the high value projects not included in the derivation of the IQI allowance;
- For projects to be treated under option 1 above, there would be an automatic re-opener provision in the event that the latest aggregate cost outturn forecast for projects to be treated under this option at any time varied by more than 20% from the agreed aggregate allowance for these projects (it is understood that a periodic 're-opener window' rather than an ad hoc approach would be preferred in the case of more than 20% forecast over-expenditure, with an (end of review) ex post re-opener in the case of more than 20% outturn under-expenditure – which the company would need to justify);
- For projects treated under option 2 above, there would be a mid-period review to determine the final allowance (with the remaining expenditure subject to a capped ex ante allowance);

5.1. Scheme complexity - conclusion

We understand Ofgem's concern to ensure that any special arrangements for high value projects neither pass a greater proportion of the risks associated with project cost or delivery overruns on customers, nor reduce the incentive on companies to deliver projects efficiently and/or find innovative cost-saving solutions. However, as Ofgem has noted from the review of LPN major projects undertaken by PB Power, EDF Energy has a highly developed and effective project approval procedure, a characteristic of which is the production of a comprehensive and detailed suite of scheme papers.

As a basis for the proposed re-openers, we believe that Ofgem's starting point would be our own project scheme approval documents. These provide an 'open book' approach which would give transparency of the project costs (including competitively tendered prices) and risk mitigation measures and contingencies; it would also provide an effective guarantee that the risks of project over-runs would be shared equitably, while retaining an effective incentive on efficiency.

6. Assessment of Capex Unit costs

6.1. Introduction and background

In the Initial Proposals, Ofgem has asserted that each DNO requires less funding for investment in its network than indicated in the Forecast Business Plan Questionnaire (FBPQ) submitted by that DNO. Ofgem's assertion that network investment should cost less is based on their assessment of each of the following:

- Quantity of work required: Is all the refurbishment and enhancement to each DNO's network required?
- Unit cost for work: Should the required refurbishment and enhancement be completed at a lower cost per unit of work done?

Ofgem has recognised the validity of our investment plans by making only minor changes to our proposed asset replacement volumes.

However, we disagree with the assertions by Ofgem that EDF Energy DNOs can carry out specific work areas at a lower unit cost than implied from their FBPQ submission for a number of reasons, specifically:

- Weaknesses in the Ofgem benchmarking approach: The selective least cost unit costs used by Ofgem can indicate spurious cost savings by not capturing total project costs;
- Market Testing of Costs: EDF Energy DNOs benefit from a specialist Supply Chain capability that uses experienced purchasing and supply chain professionals to source materials and contractors at economically efficient rates. It is difficult to understand how we could achieve lower costs than those obtained through competitive tendering;
- Drivers of Higher Costs: In some cases the nature of a project in question can lead to a level of complexity which is not possible to account for through analysis of average costs based on "normal" distributions.

Ofgem has made a positive suggestions regarding the difficulties of benchmarking 'high value schemes', which potentially represent £67m of the £145m Ofgem's adjustments for EDF Energy, and we welcome the ongoing engagement with Ofgem to define how best to take account of the costs associated with these complex projects.

We believe that the approaches Ofgem proposed to dealing with large complex 'high value' projects have merit, particularly the two ex ante options where the incentives to control risk through the pre approval and delivery phases are maintained.

Such an open book approach would capture the complexity, uncertainties and risks associated with high value, low volume projects far more effectively than a simplistic UCI based approach more suited to high volume repetitive work.

We also recognise that there is ongoing work with the Ofgem Capex team seeking to better explain the reconciliation between UCIs and total costs which has resulted in a potentially arbitrary £17m adjustment to 'non modelled' costs.

It is important that this engagement continues to improve the mechanisms behind Ofgem's asset replacement allowances. We will also provide specific detail of £11m of inconsistencies and errors we believe we have identified under separate cover as part of this ongoing engagement.

The remainder of this section discusses each of the above issues in more detail, before setting out responses against specific asset categories.

6.2. Weakness in the Ofgem benchmarking approach

Our understanding of the Ofgem benchmarking approach is based on the Initial Proposals – Allowed revenue – Cost Assessment; Ref 94/09, Sections 3.59 – 3.64 ("Unit costs benchmarking").

Ofgem has defined an assumed "efficient" value for each of the unit cost categories in the FBPQ based on a combination of:

- The independent view provided by their consultants PB Power, and;
- The industry median, based upon the unit cost schedules as provided in the DNO FBPQs submissions, corrected for any differences identified through the calculation of the implied unit cost.

For each cost category, Ofgem has determined the unit cost that each DNO should be allowed as the lower of:

- Ofgem's assumed efficient cost; and
- The unit cost submitted by the relevant DNO.

The asymmetric nature of allowances applied to DNOs, with Ofgem always selecting the lowest unit cost of its benchmark or the DNO costs, precludes any errors in cost assignment being balanced out across cost categories. This leads Ofgem to assert potential efficiency savings by comparison to an imaginary and unrealistic "ideal DNO" – meaning these savings are themselves unrealistic.

6.3. Definition of Unit Costs

It is almost impossible to define a cost categorisation framework without some ambiguity in the definition of the specific cost categories. In the case of the cost categorisation for the FBPQ submission, little has been done to identify such ambiguities, and seek the industry agreement necessary for all costs to be submitted on a consistent basis.

For example, the unit cost definitions do not account for consistency of asset ratings or cable sizes, where significant differences in standards exist between DNOs.

Legitimate variations in unit costs can also be driven by location factors, such as value of land and load density being served. Cable per km costs can also vary depending on the average run length and installation environment, as fixed costs will represent a higher proportion of costs where projects comprise of relatively short lengths in complex congested urban environments. UCI benchmarks should account for these, and other, legitimate variations.

Where a DNO anticipates many units of work for a particular cost category (e.g. LV service replacements, LV cut out changes, or 11kV RMU changes) the errors in cost predicted by a standardised unit cost will average out. However, this is not the case for cost categories such as EHV and 132kV plant with few units of work where the observed variation in efficient costs may be large relative to the unit cost. Future costs could reasonably vary from project to project without sufficient volumes of work to balance the costs risk introduced through UCI based projected allowances.

Given the level of ambiguity in definitions, it is inevitable that some of the variation in the unit costs observed from FBPQ submission arises from different approaches to allocating costs across the various cost categories. For example, the civil engineering costs associated with new substations can be allocated in a variety of different ways between transformers, switchgear and cable works in determining the primary UCI. Alternatively, these civil engineering costs could form part of the other 'non-modelled' costs.

Ofgem's benchmarking approach does not allow for such differences in cost allocation and so lead to reasonable costs being disallowed. To illustrate how significant this can be, we consider our recent £50m substation refurbishment at Bankside. This included refurbishment to several types of equipment, each of which has its own UCI for Ofgem's benchmarking; however, a significant element of that total cost was not directly related to those types of equiptment. Specifically, £32m of costs (covering civil works and balance of plant costs) needed to be allocated across nine units of 132kV switchgear, six 132/20kV transformers, twenty-three panels of 20kV Switchgear and eighty-four panels of 11kV switchgear.

This cost allocation can be done in a number of different ways, as shown in the table below: allocating by value (assuming the common costs are allocated to the equipment according to installed value of that equipment); allocating by volume (assuming the costs are split equally by the number of plant items); or allocating based on retaining fixed UCIs for some plant items.

The "LPN 123" and "Ofgem 132" columns illustrate the effect of fixing 132kV plant UCIs at LPN C2 unit costs and Ofgem Initial Proposals unit costs and allowing the 11kV and 20kV unit costs to float freely). Whilst these last two examples are illustrative they are based on observed costs, the wide range of potential values for the same project costs shows the potential risks of misallocation.

Bankside Costs		By Value	By Vol	LPN 132	Ofgem 132
	Vol	UCI	UCI	UCIs	UCIs
132kV Switchgear	9	1118	669	1333	700
132kV Transformers	6	5353	2218	1785	1077
11kV Switchgear	84	55	280	193	651
20kV Switchgear	23	137	309	479	1616

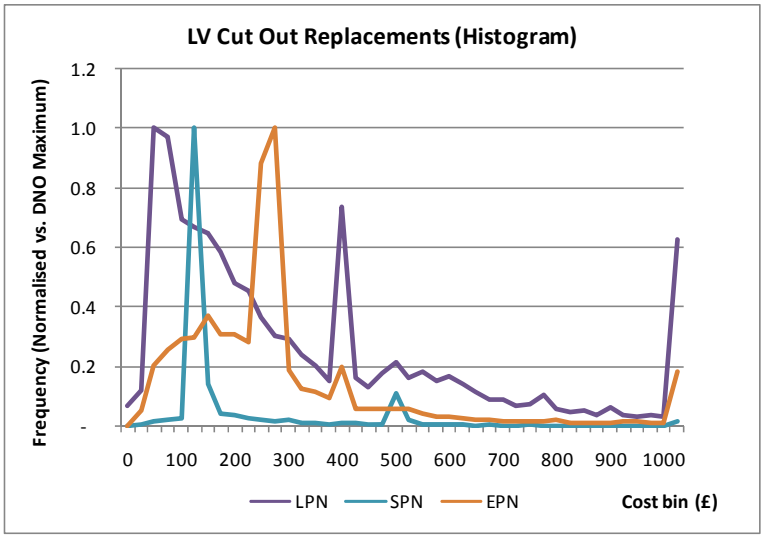
Selecting least cost UCIs as Ofgem has done, would in such circumstances erroneously remove £30m of costs as shown below.

Bankside Costs		By Value	Costs £k	Ofgem UCI	Cost £k
	Vol	UCI			
132kV Switchgear	9	1118	10061	700	6300
132kV Transformers	6	5353	32116	1077	6462
11kV Switchgear	84	55	4616	59	4956
20kV Switchgear	23	137	3140	59	1357
			49932		19075

6.4. Use of the Industry Median

Ofgem appears to have chosen to select UCIs based on industry median values. The median value will reflect the most common job cost, but will not account for less frequent, expensive jobs.

As an example, the following chart shows the DPCR4 cost distribution of LV Cut Out jobs across our three DNOs. (We do not separate overhead and underground cost data, as the nature of the work is identical).



This data shows that the DNOs display different spreads in costs; some jobs are booked with low costs (e.g. aborted jobs) and some reflect far higher costs in excess of £1000.

More expensive jobs will occur where we encounter the complexities associated with urban working, as we have described on a number of occasions, including underground utilities congestion, costly surface reinstatement and a frequent need to work within densely populated sites or out of hours.

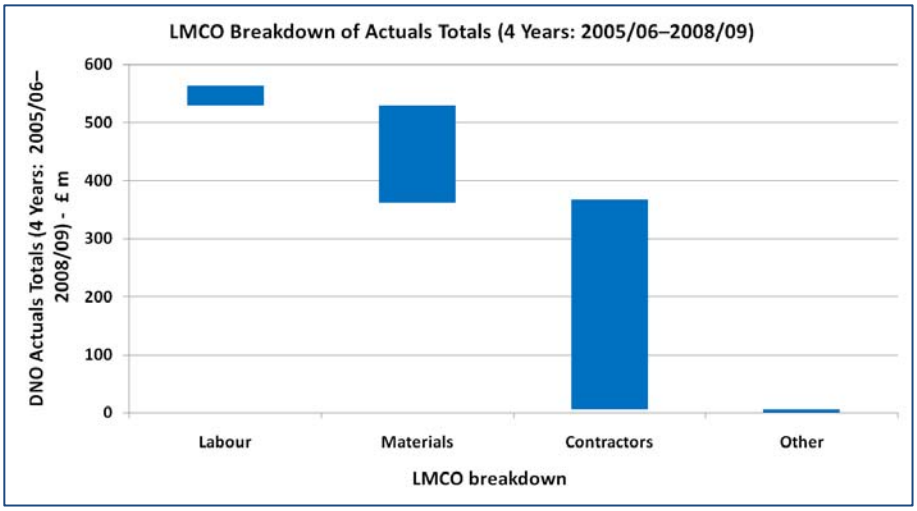
Ofgem's use of the industry median as a basis for asserting efficient costs will unfairly penalise DNOs with a high proportion of urban working, such as LPN. To account for these more expensive jobs Ofgem should instead benchmark based on the industry mean.

We will return to this issue in when we discuss specific asset adjustments.

6.5. Market Testing of Costs

We believe that the best way to ensure that cost levels are efficient is through market testing – i.e. where a DNO establishes what alternative providers would charge to carry out the relevant work. This is most effective where the market testing acts as a tendering process, with the most efficient provider having a contract to deliver the work consistent with their offered prices. This avoids the problem with purely academic forms of market testing, where the person deriving their "theoretical" view of the efficient does not have to deliver work consistent with those costs – so does not bear the consequences of errors in their theoretical view.

The graph below shows a breakdown of historic costs for four complete years of DPCR4. Of this spend, 94% is attributable to market tested contractor and materials costs (64% and 30% respectively). Only a small portion of costs totalling 7% stem from labour costs and "other" costs, which comprises of pensions, margins, land and balance.



In particular major 132kV and EHV projects, where Ofgem has made significant adjustments to our allowances, are all delivered through market tested arrangements. All materials costs have been market tested over the DPCR4 period. Other contractor costs, including those deriving from mixed opex and capex contracts such as civil excavations costs have also been market tested in the last 5 years.

6.6. Drivers of Higher Costs

Complexity

The unit costs for major schemes, particularly in the Central London area, must capture the differences in equipment specification discussed earlier, and also the additional complexity of executing the works. These complexities lead to higher indirect planning costs and also higher direct costs, including higher civil costs, installation costs and safety costs, more switching and more expensive supplementary costs associated with more phases of work.

We have already detailed in our responses to supplementary questions (e.g. NI_5029), and restated in our discussion on indirect costs in this response the factors including subsurface installations, confined spaces, deep tunnelling, space restrictions, forced ventilation and resulting multiple phases of work that all lead to increased costs for plant and associated equipment and their installation. These must be recognised in Ofgem's treatment of higher voltage (33kV and above) unit costs or as part of 'high value schemes' to ensure that reasonable overall costs are allowed.

Regional Cost Factors

Ofgem has already acknowledged that costs to do otherwise equivalent jobs on Distribution Networks do vary, for a number of factors driven by regional effects and complexities of working in urban environments. Allowances have been made in Opex benchmarking for these costs, and we submitted a paper on 19 June 2009 in which we demonstrated that these factors apply equally to reinforcement and replacement work.

Our interpretation of the Initial Proposals is that full regional and urbanity adjustments, recognised in the Opex benchmarking, do not seem to have been consistently applied for Capex.

In some categories it appears that Ofgem has allowed for some additional cost above that implied by Ofgem's baseline value, as set out in the Allowed Revenue Cost Assessment Appendix 6 table 12, yet in other areas no allowances have been made.

In particular, allowances appear to have been made for LPN across LV and HV job types, but Ofgem has not acknowledged these legitimate increases in cost in the EHV and 132kV UCI categories. Few allowances appear to have been made for regional and urban costs for EPN and SPN which we believe is incorrect.

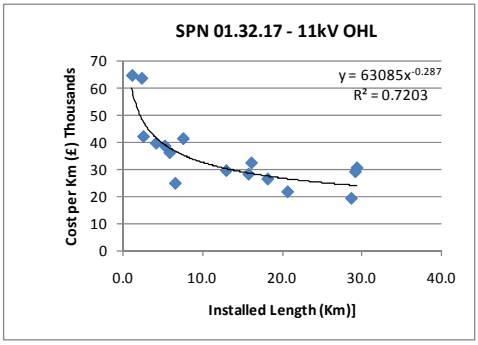
Short Cable Runs

In addition to Complexity, Regional and Urbanity factors, the length of cable runs will have an impact on UCIs for cable and overhead line.

In such jobs, there are fixed and variable elements of cost. In shorter runs, the fixed costs make up a higher proportion of the overall cost. This means that for shorter runs the observed unit cost (i.e. cost per kilometre) will be higher.

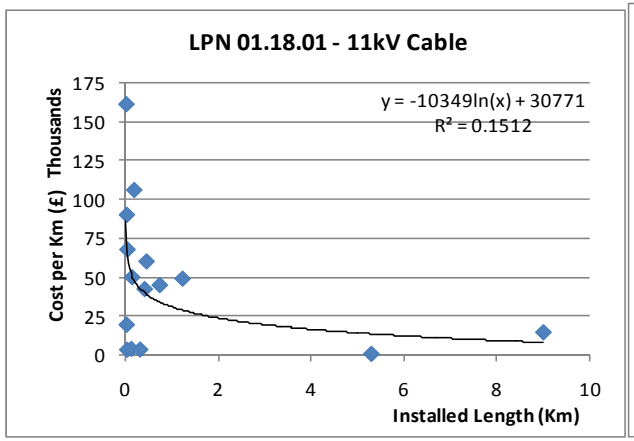
Fixed costs would include, for instance, some of the management and clerical time required to plan and schedule the work. There is also a proportion of the delivery engineer or contractor's productive time, such as travelling to and from site, ordering and collecting materials, and administrative tasks.

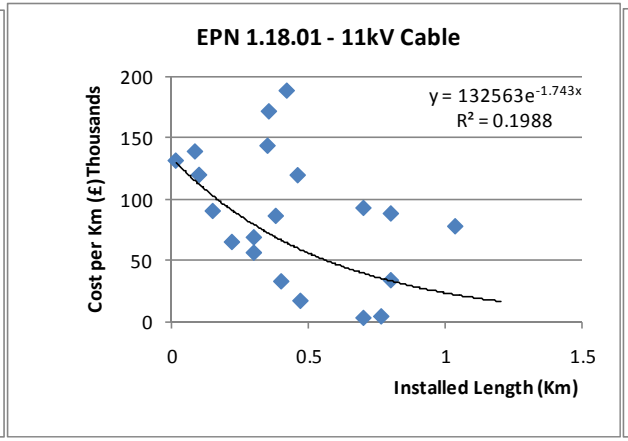
The chart below sets out a sample of SPN 11kV overhead line jobs. From this it can be seen that a strong correlation exists between installed length and unit cost.

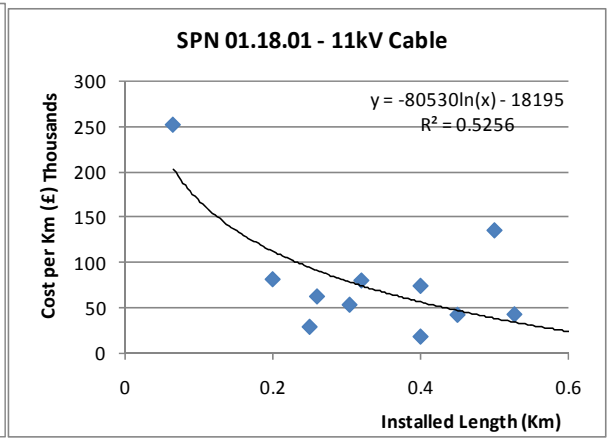


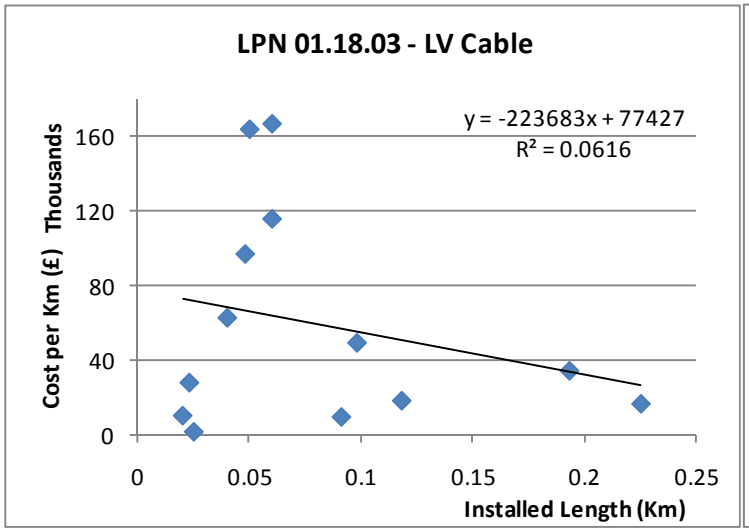
This relationship is of the form $Y=X^{-a}$, implying that cost will increase exponentially as the installed length decreases.

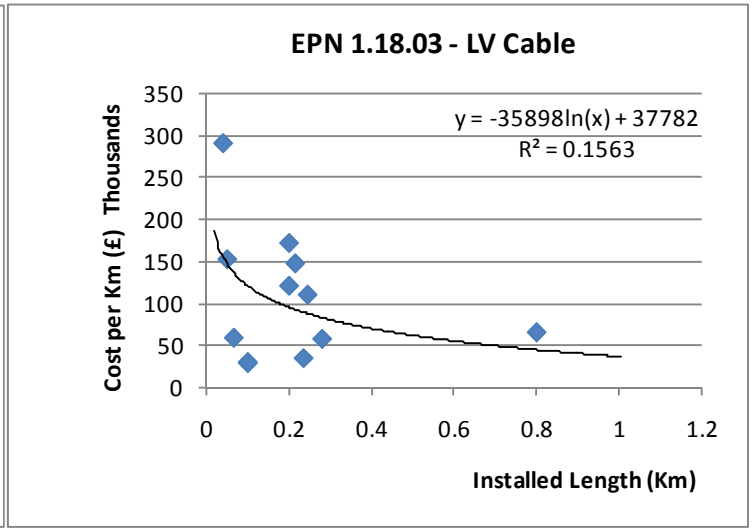
A similar effect can be observed in the following charts looking at 11kV and LV underground cable; each displays a trend of the form $Y=X^{-a}$ or $Y=-Ln(X)$. The correlation coefficients in these cases are weaker, though the installed lengths are much shorter than the previous overhead line example. At these lengths, particularly in London, a number of other factors will be associated with driving the observed UCI.


LPN 01.18.01 - 11kV Cable
y = -10349ln(x) + 30771
R² = 0.1512
Cost per Km (£) Thousands
Installed Length (Km)
0
25
50
75
100
125
150
175
0
2
4
6
8
10


EPN 1.18.01 - 11kV Cable
y = 132563e-1.743x
R² = 0.1988
Cost per Km (£) Thousands
Installed Length (Km)
0
50
100
150
200
0
0.5
1
1.5


SPN 01.18.01 - 11kV Cable
y = -80530ln(x) - 18195
R² = 0.5256
Cost per Km (£) Thousands
Installed Length (Km)
0
50
100
150
200
250
300
0
0.2
0.4
0.6


LPN 01.18.03 - LV Cable
y = -223683x + 77427
R² = 0.0616
Cost per Km (£) Thousands
Installed Length (Km)
0
40
80
120
160
0
0.05
0.1
0.15
0.2
0.25


EPN 1.18.03 - LV Cable
y = -35898ln(x) + 37782
R² = 0.1563
Cost per Km (£) Thousands
Installed Length (Km)
0
50
100
150
200
250
300
350
0
0.2
0.4
0.6
0.8
1
1.2

(Note: we have insufficient datapoints to provide the SPN LV cable relationship).

Whilst these results do not establish a hard and fast scaling between installed length and unit costs, they demonstrate that installed length and unit costs are associated.

We do not believe that Ofgem has normalised their benchmarking to take account of the mean installed length across DNOs. We believe this should be done before any reasonable conclusions can be drawn in determining efficient costs for the industry.

6.7. Specific Asset Adjustments

In the tables below we have summarised the specific asset related adjustments we believe we have addressed or require further work to ensure reasonable allowance are made.

Table: LPN explanation of Ofgem's proposed reductions

(Comments in red relate to new information presented in this response; black comments relate to information previously provided to Ofgem).

EDFE LPN £m (07/08 prices)	DPCR5 Forecast	Reduction from DNO Forecast			Quantity explained by UCI restatement	Commentary	Total quantity explained
Asset		Total	Unit Cost	Volume			
132 kV CB (ID & OD)	41.3	19.8	19.8	0.0	20.7	Separate identification of exceptional civil works, associated cable and switchgear and costs for St Pancras (uncertain so no volumes entered) has reduced UCI to	19.8
132kV UG Cable (Non Pressurised)	32.8	15.0	11.9	3.1	12.8	Separate identification of potential costs associated to one uncertain project where no volumes identified has reduces UCI to £1110	12.8
6.6/11 kV CB (GM) Distribution	8.2	6.3	6.3	0.0	6.3	Restated 'average UCI' in to Primary and Distribution UCIs. Distribution UCI restated as £26k / panel as replacment of HV customer VMX switchgear (£10k per	6.3
Cut out Replacement (UG)	5.3	3.3	3.3	0.0	0.0	Without more detailed benchmarking to account for urban complexity we believe Ofgem should allow our	3.3
6.6/11 kV RMU	34.0	3.0	3.0	0.0	0.0		0.0
6.6/11kV UG Cable	7.2	2.7	2.7	0.0	0.0		0.0
66 kV Transformer	3.5	2.6	2.6	0.0	0.0		0.0
66 kV CB (ID & OD)	2.7	2.0	2.0	0.0	1.4	Restated as per 132kV CB - we only use 132kV equipment	1.4
33kV UG Cable (Non Pressurised)	5.9	2.0	2.0	0.0	0.0		0.0
LV Board (WM)	3.3	1.9	1.9	0.0	0.0		0.0
33 kV Transformer (GM)	3.5	1.1	1.1	0.0	0.0		0.0
LV Main (UG Plastic)	2.4	0.9	0.9	0.0	0.0		0.0
6.6/11 kV Transformer (GM)	8.5	0.3	0.3	0.0	0.0		0.0
33 KV CB (ID)	2.8	0.2	0.2	0.0	0.0		0.0
Service Replacement (UG)	0.6	0.1	0.1	0.0	0.0		0.0
Subtotal	**161.9**	**61.2**	**58.1**	**3.1**	**41.1**		**43.5**
Unrecovered cable total		2.7			0.0	Unrecovered cable reductions may be explained by benchmarking to account for average installed length	2.7

Table: SPN explanation of Ofgem's proposed reductions

(Comments in red relate to new information presented in this response; black comments relate to information previously provided to Ofgem).

EDFE SPN £m (07/08 prices)	DPCR5 Forecast	Reduction from DBO Forecast			Quantity explained by UCI restatement	Commentary	Total quantity explained
Asset		Total	Unit Cost	Volume			
132kV CB (ID & OD)	25.8	6.4	6.4	0.0	0.0		0.0
6.6/11 kV RMU	17.6	4.2	4.2	0.0	0.0	RMU spec and unit costs has RTU as standard in SPN	4.2
132 kV Transformer	12.1	3.5	3.5	0.0	0.0		0.0
33 kV Transformer (GM)	10.0	3.2	3.2	0.0	0.0		0.0
Service Replacement (OHL)	4.3	2.2	2.2	0.0	0.0	Mural Services costs appear to have erroneously been disallowed	2.2
33kV UG Cable (Non Pressurised)	17.8	1.9	1.9	0.0	6.8	Definition of consequential costs from other projects reduces UCI to £245k, below industry median	1.9
6.6/11 kV Transformer (GM)	5.6	0.7	0.7	0.0	0.0		0.0
Cut out Replacement (UG)	2.8	0.6	0.6	0.0	0.0	Ofgem have reduced SPNs UCI to less than the industry average, median and Ofgem's baseline	0.6
6.6/11 kV CB (GM) Primary	8.4	0.5	0.5	0.0	0.0		0.0
Cut out Replacement (OHL)	0.2	0.0	0.0	0.0	0.0		0.0
LV Main (UG Plastic)	1.2	0.0	0.0	0.0	0.4	UCI restated to reconcile mix of replacement and capital fault work (lower UCI as fewer/no service replacement costs)	0.4
Sub-total	**105.7**	**23.3**	**23.3**	**0.0**	**7.2**		**9.3**
OHL total	41.7	11.1	11.1	0.0	0.0	OHL reductions require benchmarking to account for average installed length	11.1

Table: EPN explanation of Ofgem's proposed reductions

(Comments in red relate to new information presented in this response; black comments relate to information previously provided to Ofgem).

EDFE EPN £m (07/08 prices)	DPCR5 Forecast	Reduction from DBO Forecast			Quantity explained by UCI restatement	Commentary	Total quantity explained
Asset		Total	Unit Cost	Volume			
33kV UG Cable (Non Pressurised)	19.7	8.3	3.5	4.8	2.8	Separate identification of non modelled costs gives UCI of £340k	7.6
132 kV CB (ID & OD)	10.1	2.5	2.5	0.0	0.0		0.0
6.6/11 kV CB (GM) Primary	18.2	2.4	2.4	0.0	1.3	Consequential costs realted to volumes not in NL3 identified and UCI restated at £58k (10% reduction)	1.3
33 kV Transformer (GM)	13.0	2.2	2.2	0.0	0.0		0.0
132 kV Transformer	6.4	2.0	2.0	0.0	0.0		0.0
Cut out Replacement (UG)	2.0	1.0	1.0	0.0	0.0	Without more detailed benchmarking to account for urban complexity we believe Ofgem should allow our	1.0
33kV OHL (Tower Line)	1.3	0.9	0.9	0.0	0.0		0.0
33 KV CB (ID)	11.0	0.8	0.8	0.0	0.0		0.0
6.6/11 kV Transformer (GM)	6.0	0.8	0.8	0.0	1.2	With revised volumes UCI restated at £12.8k now equivalent to industry median	0.8
6.6/11 kV RMU	16.5	0.7	0.7	0.0	0.0		0.0
132kV UG Cable (Non Pressurised)	3.2	0.4	0.4	0.0	0.0		0.0
LV Board (WM)	0.5	0.3	0.3	0.0	0.0		0.0
6.6/11 kV CB (GM) Distribution	6.0	0.2	0.2	0.0	0.0		0.0
Cut out Replacement (OHL)	0.2	0.1	0.1	0.0	0.0	(see above)	0.1
6.6/11 kV CB (PM)	0.3	0.1	0.1	0.0	0.0		0.0
Sub-total	**114.5**	**22.7**	**17.9**	**4.8**	**5.2**		**10.7**
OHL total	42.4	15.5	15.5	0.0	0.0	OHL reductions require benchmarking to account for average installed length	15.5

In our response to NI_5075 we have used restated NL3 volumes and provided detailed descriptions of 'non-modelled' costs not directly associated with UCIs and volumes to enable Ofgem to reconcile NL1 and NL3. Given the detailed explanations provided to PB Power earlier in the review, we believe these should explain any volume and cost issues Ofgem has not been able to reconcile and are happy to undertake further work with Ofgem if there are still costs they believe require further explanation.

Where it has been possible, particularly for LPN, to detail specific exceptional costs associated with specific projects, we have done so to demonstrate to Ofgem that our underlying UCIs for EHV equipment are comparable to other DNOs for example LPN 132kV CBs and 132kV cable costs.

6.8. LV Services

In the Initial Proposals, Ofgem has selected baseline UCIs for LV services (overhead and underground) which are lower than the industry median values.

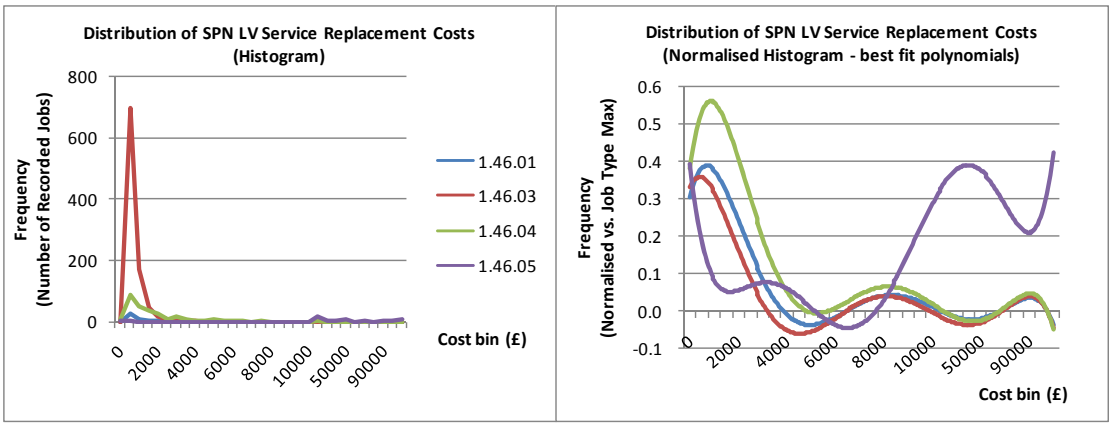
For SPN service replacements, we forecast a cost of £6.9m, and Ofgem has applied a reduction of £2.2m (32%). This reduction has been applied to overhead services (a reduction of 51% in the category).

SPN benchmarks well compared with the industry values (published in table 12 of appendix 6 of the Allowed Revenue Cost Assessment) in underground services. EPN benchmarks well in both overhead and underground.

In our response to supplementary question NI5040 in which we set out the costs and volumes for LV Services we set out how we have made provision for more expensive mural services in SPN's overhead service UCI. The UCI for "Replace Overhead Services" alone can in fact be seen to be £380, which is lower than Ofgem's baseline cost in this category.

In the absence of the detail of Ofgem's reductions, the £2.2m reduction for SPN appears to correspond to the costs of mural services identified in NI5040 (£2.3m).

Historic job data from the DPCR4 period shows that whilst "Replace Overhead Services" is the most numerous type of LV Service job in SPN, with a median value in the order of £500 there are other types of work containing some much more expensive jobs – particularly Mural Services.



6.9. LV Cut Out Replacements

In the Initial Proposals Ofgem has again selected baseline UCIs for LV cut out replacements (overhead and underground) which are lower than the industry median values.

Ofgem has applied reductions to LPN of £3.3m from an FBPQ forecast of £5.3m (i.e. a 62% reduction), as set out in table 16 of appendix 7 of the Allowed Revenue Cost Assessment. This reduction reflects an allowed UCI of approximately £190, which is the industry median value. We believe this is unfair treatment; as a median value

reflects the most common cost, but does not account for the less frequent expensive jobs. To account for these more expensive jobs Ofgem should at least allow for the industry mean. In addition, we believe that the regional and urbanity costs associated with London should be allowed for. In the LV Cut Outs chart presented earlier in this section we can also observe small peaks in EPN and SPN at a cost of around £400-500 per job, which may demonstrate higher costs in outer London areas within EPN and SPN where similar working conditions are experienced.

Without more detailed benchmarking Ofgem should allow LPN's Cut Out costs, which are consistent with an efficiency reduction over historically observed values (£510 for DPCR5 vs. £572 in DPCR4).

For EPN, Ofgem has applied a reduction of 50% to both overhead and underground cut out replacements. For overhead this appears to reflect a UCI of £150, which is below the industry mean (£210), median (£190) and Ofgem's baseline UCI of £160. For underground the situation is similar. We believe there is no basis for these reductions, and that, without more detailed benchmarking, EPN should be allowed its own forecast UCIs.

For SPN, we have submitted a UCI of £200 for both overhead and underground cut outs. This is comparable to the industry medians of £190 for underground and £200 for overhead. Ofgem appear to have applied a reduction of 21% to the underground component of SPN's costs, reflecting an allowed UCI of £157, which is below the industry mean, median, and Ofgem's baseline UCI of £160. We believe there is no basis for this reduction, and that, without more detailed benchmarking, SPN should be allowed its own forecast UCIs.

6.10. SPN RMU

The SPN RMU UCI costs include for a RTU which is standard supply for SPN, whereas for EPN and LPN this was treated separately as the application is more selective due to the existing number of RTUs in service.

SPN RMU costs without RTUs should be higher than EPN RMU costs to allow for regional cost factors (we believe a six percent relative increase in regional costs should be applied to SPN).

7. Other cost assessment issues

7.1. Average cost "frontier

We are pleased that Ofgem has responded to our concerns about inconsistencies in the reporting of DNO cost data by using an average cost frontier (for DNOs with above average costs) for certain cost categories (network operating costs and related non-operational capex). However, Ofgem continues to use an upper quartile frontier for all DNOs for indirect costs (and the balance of non-operation capex) despite the fact that the statistical robustness of the relevant regression models is even weaker.

The weakness of the models is evidenced by the fact that the Groups analysis fails the Ramsey RESET model specification tests in four of the nine cost categories considered. The log cost functions employed by Ofgem are linear functions of cost drivers. The Ramsey RESET test is designed to be sensitive to nonlinearity in the log cost function. Nonlinearity that is not taken account of in the model can have very serious consequences for the calculation of efficiency scores, so failure of this test requires thorough investigation. Of the four models which fail the test, only one of these (Group 3) is discussed in the document (paragraph 1.33, bullet point 2) but all are potentially serious, as failure to deal with these non linear effects will give rise to biased and misleading calculations of the fitted cost values.

It must also be remembered that the Ofgem analysis is based on a small sample of fourteen DNOs observed for four years. The cost data exhibits substantial variation. Variation in cost drivers explains between 30% and 76% of the variations in costs for the cost components considered in the study. As a result, the estimated cost relationships are affected by statistical error and this is transmitted to estimates of efficiency scores and to estimates of the upper quartile of the scores.

Although statistical aspects of the analysis are given close attention at a number of points in the Ofgem study – for example the results of a variety of statistical tests are reported, conventionally employed measures of accuracy of estimation such as estimated standard errors are not reported. So, while Ofgem has investigated whether its modelling process is biased it has published no evidence that its approach produces accurate results.

Ofgem proposes to use the upper quartile efficiency score as a key element in their benchmarking exercise. In order to develop a view on the margin of error in the upper quartile estimates we employed a bootstrap procedure.[1] The result of this analysis

[1] The bootstrap procedure was implemented as follows.1000 bootstrap samples were drawn. Each sample was produced by sampling 14 DNOs with replacement from the list of 14 DNOs and then assembling a data set to which each sampled DNO contributed its 4 years of data.The Top Down and Single Groups analyses were then done for each sample following the Ofgem methodology, resulting in an upper quartile score estimate for each of the 1000 samples. The variability of these bootstrap sample estimates is informative about the accuracy of the upper quartile estimates reported in the Ofgem study.

suggests that variation in the quartile estimates is quite substantial. The estimated standard error of the upper quartile estimates are around 3% and they have interquartile ranges around 4%. The mean efficiency scores are close to 100 by construction, and so this variability reflects variation in the estimated dispersion of the distribution of efficiency scores.

Quartiles are less accurately estimated than measures of central location such as medians and means. Ofgem should consider whether using inaccurately estimated upper quartiles in this benchmarking exercise is good practice in an exercise of this importance. This is particularly important given that the majority of DNOs are failing to meet their cost allowances in the current period, allowances that were set by reference to an upper quartile.

There is no justifiable reason for adopting a tighter standard in such conditions. Ofgem has not demonstrated a sufficiently robust case for denying cost recovery. Ofgem should accept the weakness of the data and adopt an average cost frontier in all cases.

7.2. Extrapolation and regulatory judgement

In Ofgem's analysis strong restrictions are placed on the cost relationships that are estimated *en route* to its benchmarking results. In the face of limited amounts of noisy data and poorly measured cost drivers, it is understandable that this strategy is adopted. However a result is that, in coming to a view on the appropriate values of costs a degree of extrapolation sometimes takes place and this can disadvantage DNOs with relatively extreme values of cost drivers.

Therefore, just as there is regulatory judgement shown at various points as the benchmarking results are developed[2] so there should be judgement exercised when interpreting the results delivered by Ofgem's simple parsimonious cost relationships at the boundaries of their applicability.

Two examples of this are discussed in more detail below:

DEA analysis

In paragraphs 1.26 - 1.28 of Appendix 5 of the DCPR5 Initial Proposals document Ogem presents the outline of its DEA analysis. This analysis identifies EDFE EPN as one of three DNOs on the efficient frontier, ranked first. By contrast the Top Down regression ranking of Ofgem places this DNO 13th out of the 14 considered. The Single Group and Groups benchmarking analyses come to a similar conclusion.

[2] See Paragraph 1.8 of Appendix 9 of the DPCR5 IP document.

The key to explaining the result is that the DEA analysis places no restrictions on the functional form of the cost relationship. By contrast the Ofgem model requires log costs to be linear functions of the composite cost drivers.

Ofgem's linear, single-composite-driver models sometimes do not fit well at the extremes and DNOs whose business situations place them at the extremes are disadvantaged by Ofgem's reliance on simple linear models. Ofgem dismisses the DEA result as a "shortcoming of DEA analysis". In fact it is the consequence of the unrestrictiveness of the DEA model and its lack of reliance on extrapolation.

The DEA analysis should alert Ofgem to the fragility of their core results which, for some DNOs, rely on extrapolation of simple cost relationships across the boundaries of their applicability.

Group 3 Indirect Costs

In the Group 3 analysis Ofgem employ a model in which there is a single cost driver - Modern Equivalent Asset Value (MEAV) - which does not vary across the 4 years of data employed.

For the EDF Energy, group MEAV takes a value 40% higher than the next largest DNO group and 90% larger then the average MEAV of the other DNO groups.

The location of the fitted relationship is strongly influenced by the cost and cost driver data for the 6 smaller DNO groups and on extrapolating to the cost driver value experienced by EDF Energy a large positive residual is found for EDF Energy which is wholly attributed by Ofgem's analysis to inefficiency.

We are unaware of any law of economics or engineering that suggests that the nearly linear relationships between log Costs and log MEAV found for the smaller DNO groups should persist to the levels of MEAV found in our business. Neither we nor Ofgem has any idea how the six smaller DNO groups' Group 3 costs would turn out if their business had MEAV levels of the sort found at EDF Energy. Therefore, attributing the lack of fit of the Ofgem Group 3 cost relationship at extreme values of MEAV to inefficiency is unreasonable.

7.3. Consultants' reports

In their May Policy paper Ofgem rightly concluded that "comparative analysis is not appropriate for all costs and for these we rely on other techniques. We have appointed consultants to carry out a review of non-operational IT and property costs…" Indeed, in para. 4.69 of the Cost Assessment consultation Ofgem confirms its policy of excluding these costs from the benchmarking. However, although allowances for these items have been set by reference to the consultants' reports, Ofgem has after all included the costs in the benchmarking, with the result that any resultant change in efficiency scores resulting has the effect of increasing of reducing cost allowances elsewhere.

Ofgem's approach to setting property and IT costs is also inconsistent. Ofgem are setting a proportion of IT and property costs via the benchmarking analysis, as all property and IT non op capex has the indirect cost benchmarking efficiency percentage applied to it. This effectively means that a DNO that leases all its property gets its costs set through the expert review whereas a DNO with a significant amount of freehold property has an element of its costs set via the flawed benchmarking process. This is both illogical and unfair as it rewards DNOs based on how they have chosen to run their business not on whether that choice was efficient.

We believe that Ofgem has made an error in not complying with its own policy on this matter and that the benchmarking should be re-done with the IT and Property costs removed.

7.4. Costs transferred to Network Investment

Paragraph 4.71 of the Cost Assessment consultation states that a proportion of non-operational capex has been transferred into the costs modelled by the Network Investment Team (£20m in the case of EDF Energy). However, there is no evidence of these costs appearing in the Network Investment modelling. This omission would bias results and is an error which must be corrected.

7.5. Workforce renewal

Ofgem's approach to benchmarking discriminates against first-movers..

We understand that the baseline workforce renewal allowances have been set via the regression analysis. Table 2.9 of the cost assessment paper demonstrates that EDF Energy accounts for 50% of the DPCR4 workforce renewal expenditure in the operational costs category i.e. those costs which are subject to benchmarking.

As Ofgem has left these costs in the benchmarking then EDF Energy will appear less efficient than either the industry average or the upper quartile. Consequently, they will get a larger efficiency percentage applied to their base costs than would be the case if the costs were excluded. This approach is clearly inappropriate as it penalises first movers and particularly those companies who have incurred the costs in the operational costs category.

Ofgem has stated that it has had to leave workforce renewal costs in the base costs because not all DNOs have been able to split them out. This is unacceptable to us. If DNOs cannot adequately allocate their costs to the respective cost categories, then Ofgem should pro rata the workforce renewal expenditure based on the total expenditure in each FBPQ category.

7.6. Traffic Management Act

Ofgem's position that all TMA costs will be considered as part of a reopener in DPCR5 needs further consideration. EDF Energy is unique in that Kent County Council has

already had a permit scheme approved by the Secretary of State. In addition, the Secretary of State is also considering a permit scheme submitted by TfL and 18 of the London Boroughs. A decision on this scheme is due before the end of October 2009 and we believe it is highly likely that it will be approved. The Kent scheme will go live in January 2010 and, if approved, the London-wide scheme will also go live at that time. Therefore, at the start of DPCR5 a significant proportion of EDF Energy's network (approximately 30% of our customers) will be covered by active permit schemes and, as shown below, the remainder of our network will be subject to permit schemes by 2011.

Local Authority / Aggregate Local Authority Area	Permit Scheme Implementation Timeline	% of EDF ENERGY Operating Area covered
Kent County Council	• Permit scheme implementation will commence on the 25th of January 2010	**10%**
London Local Authorities Transport for London; City of London ; Westminster; City Council; The Royal Borough of Kensington and Chelsea; London Borough of Barnet; Bent ; Bromley; Camden; Croydon; Ealing Enfield; Hackney; Hammersmith and Fulham; Haringey; Hounslow; Islington; Lewisham; Redbridge; Wandsworth	• The decision on a scheme covering the TfL and 18 of the London boroughs will be decided on by the Secretary of State before the end of October 2009 • Permit scheme implementation is expected to start early 2010	**21%**
London Local Authorities Lambeth; Newham; Southwark; Tower Hamlets; Harrow; Havering; Barking and Dagenham; Bexley; Greenwich ; Merton; Waltham Forest; Croydon; Kingston Upon Thames; Richmond Upon Thames; Sutton	• The remaining local authorities are expected to follow the successful example of the first wave of Permit scheme implementations in London. We expect the uptake to be within 2010/11	**21%**
Remaining South East England and East Anglia Local Authorities	• East Anglia local authorities are expected to be followers of London local authorities regarding permit schemes. We expect the uptake of permits to be from 2011/12 onwards, one year after London authorities. • The remainder of local authorities in South East are expected to start implementation approximately one year behind Kent.	**48%**

We have developed a detailed cost model, which we have shared with Ofgem, based on our knowledge of the actual schemes. We, therefore, believe that Ofgem has sufficient information to set ex ante allowances for EDF Energy in this area and should therefore do so.

7.7. Atypical costs – data management activities

EDF Energy currently spends around £5m p.a. on data management activities aimed at reducing reported losses and improving the accuracy of DUoS billing.

Ofgem has included £2m of these costs in the cost benchmarking (the balance is in excluded services) which, to the extent that other DNOs do not carry out this activity (of at least not on anything like the scale of EDF Energy) makes EDF Energy look relatively inefficient.

EDF Energy is effectively being penalised for responding more proactivly than other DNOs since if all DNOs responded in a similar way, the costs would be included within the benchmark. This is unfair and needs to be corrected.

8. Other Network Investment issues

8.1. Load Related (£/MVA)

Our £/MVA will be higher than that assumed by Ofgem because:

- Many of our proposed schemes require the total replacement of existing outdoor or overhead assets with new indoor or underground assets of higher capacity.
- This need to redesign the facilities (rather than replace them on a like-for-like basis) is an expanding feature of our capex programme. It derives from the need for a more radical overhaul of the network, in order to accommodate new growth on a long-term sustainable basis.

We have submitted a separate note to Ofgem on this issue. We ask Ofgem to take account of project scope in its modelling of reinforcement costs.

Ofgem's use of MEAV 'long-run' costs needs to be modified to take account of these factors.

There are also grounds for excluding from the benchmarking some types of project, e.g. those addressing N-2 security obligations. We appreciate that we could have brought these to Ofgem's notice earlier, however, these amendments have been prompted in part by the relatively recent development of the LI Output Measures and a growing understanding of how they interact with Table LR4, and we consider that the amendments are a more objective representation of the output of our reinforcement submission. We would welcome the opportunity to describe the amendments in detail and we would also welcome a detailed discussion of how these revised factors will affect Ofgem's view of the £/MVA ratio.

We responded to Supplementary Questions NI5025, NI5026 and NI5050 to discuss factors which we considered would be pertinent to Ofgem's view that our cost of added capacity is relatively high. In addition to these answers, we have provided documentation for a number of schemes and answered PB Power's detailed follow-up questions. During this work, we noted that the infrastructure planning philosophy and processes which were generally approved by the PB Power team for LPN also apply to SPN and EPN.

Inspection of the schemes against a nominal £/MVA criterion shows that many of the "relatively expensive" schemes include the provision of new or overlaid circuits, many of which are cabled and therefore high cost. Where existing substations are to be reinforced, many schemes which require larger transformers also require higher-rated switchgear – in effect, we are frequently required to rebuild the existing substation, usually with substantial building costs (which are included in our Unit Costs). Our holistic solutions will usually combine transformers and switchboard into the same project in order to make the most efficient use of scarce resources such as technical expertise and network access, and manage project and network risk (which

we identify through our EEPW process). In addition to these 'rebuilds', our EPN reinforcement submission forecasts the construction of eight new substations. For each project in LR4 we have now itemised the asset categories and volumes for each major project in some detail.

8.2. Load related capex adjustments

Ofgem has reduced our forecast of 132kV and EHV reinforcement by £50.4m by imposing volume reductions (£10.1m LPN, £16.4m, SPN, £23.9m EPN). We are surprised at these reductions, particularly as the Initial Proposals state that PB Power supported the engineering justification for the LPN General Reinforcement programme, yet still made a volume reduction of £10.1m to remove 'a small number of projects'.

We are unable to replicate Ofgem's reductions for and of the three submissions; indeed, we cannot identify any scope for volume reductions of this order.

Ofgem's cuts are, therefore, at best, lacking in transparency and, at worst, devoid of any rationale. We maintain that the reinforcement schemes listed our submission are justified against the criteria outlined in the scheme proposals and we challenge Ofgem to provide robust justification for its alternative view of the required volume of work.

Given all the above, our expectation is that Ofgem will now take full account of the additional detailed information we have provided (as described in **Error! Reference source not found.** above) as part of a further objective consideration of our 132kV and EHV reinforcement submission, and incorporate a significant reversal of the above reductions within their Final Proposals.

9. Relative Price Effects and Frontier Shift

9.1. Ofgem's approach

There is a significant difference between the allowance Relative Price Effects (RPEs) presented in Ofgem's Initial Proposals and EDF Energy's submission. When forecasting Network Investment, Ofgem has made no allowance for RPEs in the future, assuming they will be offset by future efficiency savings. The net effect of this assumption over the whole five year period is a £160m reduction for EDF Energy (some 38% of the £418m of Network Investment disallowed in the Initial Proposals). For operating costs, proposed RPEs represent a further £22m reduction for EDF Energy.

From Ofgem's methodology statement it is difficult to determine the basis for these conclusions, which limits our ability to comment on them. We have tried to reconstruct Ofgem's approach as best we can and offer some comments on it. In contrast, we emphasise again the soundness and transparency of our initial submissions.

9.2. Apparent approach

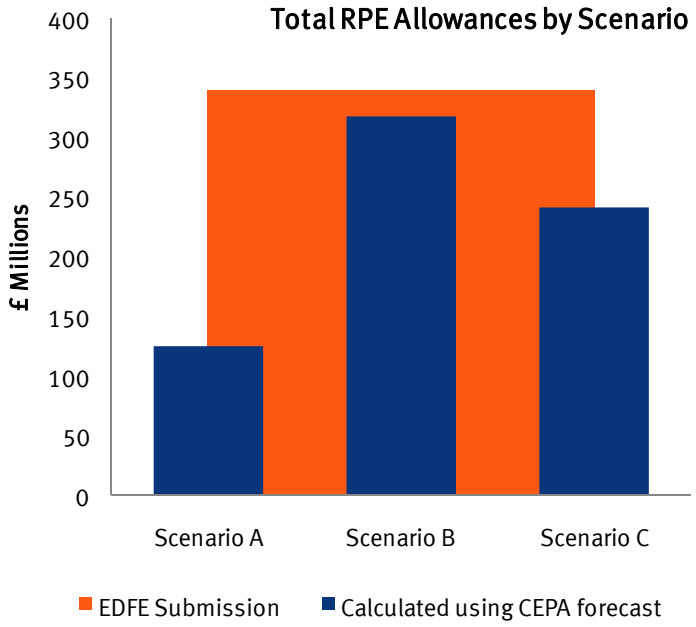
The Initial Proposals state that CEPA forecasts of RPEs have been used in conjunction with each DNOs calculated weightings in each category of expenditure. However, it is not possible to see Ofgem's actual calculations because RPEs have been netted off against asserted efficiency savings.

A more transparent approach to this important issue would have been helpful.

In an attempt to reconcile to Ofgem's allowances, we analysed three scenarios:

- Scenario A: Zero RPE effect in DR4, CEPA RPE index for DR5
- Scenario B: Using CEPA forecast for DR4 , CEPA RPE index for DR5
- Scenario C: Using EDF Energy assumptions for DR4 RPEs , CEPA RPE index for DR5

For each of these scenarios, the RPE has been broken down by DNO, cost category and type of expenditure:



Scenario B is the most the most consistent and has the best fit with EDF Energy's submission. Network Investment using CEPA's RPE indices gives £165.8m compared to EDF Energy's forecast of £159.8m. Ofgem have confirmed verbally that they have used Scenario B but we are still unable to replicate the analysis completely.

The figures are:

	Calculated using CEPA forecast	EDFE Submission
Scenario A	125.8	339.5
Scenario B	317.1	
Scenario C	241.2	

9.3. Ofgem's assumptions on future RPE

Ofgem's view on RPEs is based on the assertion that the DNOs are likely to be able to hire staff at wage levels that are lower than in previous years and should also be able to negotiate better terms with suppliers of contract labour.

However, they do not in themselves demonstrate that Ofgem is justified in not allowing a premium in wage inflation for workers with specialist electrical engineering and infrastructure skills or that real wage inflation is likely to be lower than Ofgem has assumed in previous reviews. The key question is whether the DNOs are more or less affected by these changes than a typical employer elsewhere in the economy. In our view there are two main factors that mean that DNOs are likely to be less affected than the rest of the economy by the recession. They are:

- DNOs are forecasting significant increases in investment to replace the ageing infrastructure and as such work volumes are growing. The adaptation of the distribution networks to meet the climate change agenda will only increase this level of activity; and
- the competition that the DNOs face for skilled infrastructure specialists has not abated. The likes of the transmission companies, GDNs, water and sewerage companies, Network Rail, BAA and the Olympic contractors are all proceeding with pre-recession investment plans and taking significant numbers of the same skilled professionals that the DNOs need in their work.

In its document Ofgem infers that stability and a predictable increase in the volume of work that the DNOs carry out might alleviate wage pressures in the sector. Whilst certainty is without doubt beneficial in an absolute sense, in a comparative sense it gives workers in the sector more shelter from recession, more options and more opportunity to leverage on the scarcity of their skills. To argue that an increasing demand for labour translates into lower wages would be to ignore the basic laws of demand and supply.

CEPA's analysis assumes that the same RPE should apply to contractors as to a DNO's internal labour. This position is supported by neither the historical data or the analysis presented to Ofgem in both the NERA and First Economic reports. It is also counter to the position taken at the recent GDPCR where Ofgem allowed an average RPE for internal labour of 1.5% but an average 2.5% for contractors. We acknowledge that there is no specific index that reflects wage pressures in the electricity distribution industry. Ofgem makes reference to recent movements in the BERR infrastructure output index as evidence of the downturn in the electricity. The applicability of this index for measuring wage inflation is questionable. The table below details a number of alternative indices which are, in our view more relevant.

Index	Growth rate
ONS: electricity, gas and water sector, incl. bonus	3.5%
BEAMA: electrical engineering	3.8%
BERR: civil engineering labour and supervision	5.5%
ONS: average earnings growth, incl. bonus	2.5%
ONS: retail prices index	(1.3%)

The table shows a significant differential in DNO wage inflation It is also worth noting that the BEAMA index has continued to grow at a constant level since the cut-off date for the table: the provisional September 2009 release has annual wage inflation for electrical engineers running at 3.7%, which we suspect will turn out to represent a widening of the differential to average earnings growth when data from the ONS series becomes available.

We believe that based on the evidence discussed above Ofgem must make an appropriate RPE allowance for contractors recognizing the significant differential between this labour group and a DNOs own internal workforce.

9.4. Ofgem's efficiency assumption – network investment

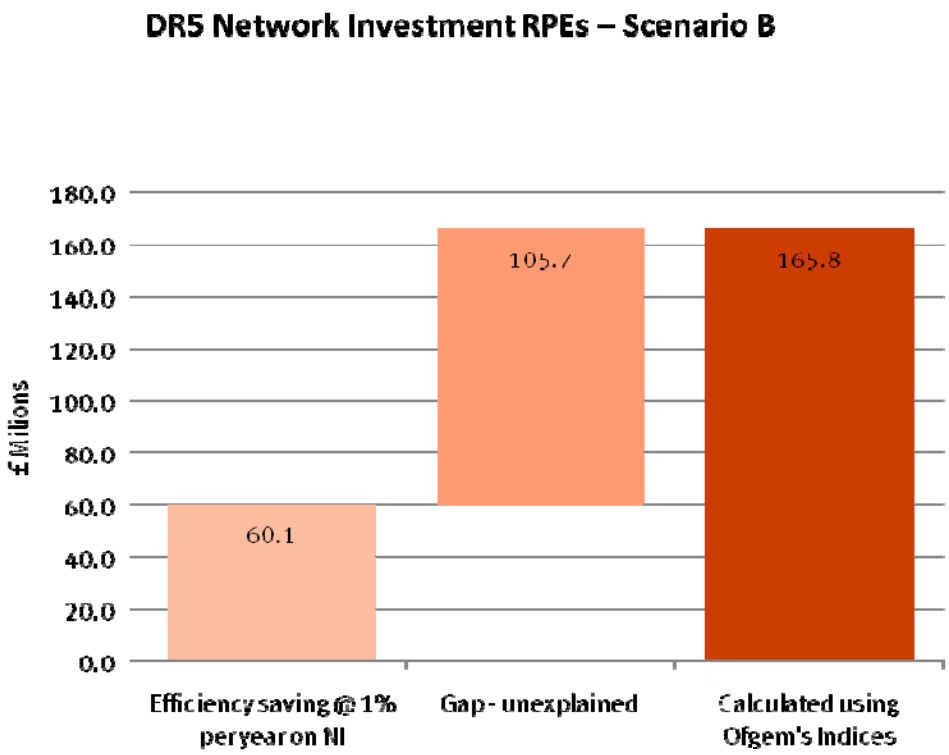
Ofgem appears to allow 0.9% for RPEs for Network Investment, but then entirely nullifies this by asserting that Network Investment will experience a 1% per annum efficiency improvement.

However, we have attempted to replicate Ofgem's calculations and cannot reach the same conclusions. This may indicate that there are errors with Ofgem's analysis.

The chart below compares a 1% efficiency saving on Network Investment compared to the RPEs resulting from CEPA's RPE indices.

It shows an unexplained gap of £105.7m, or put another way, an implied efficiency growth factor of around d 2.1% p.a.

Ofgem should correct this error by allowing EDF Energy at least £105.7m of RPE for Network Investment.



9.5. Efficiency improvement – potential double count

We believe that Ofgem may have double counted efficiency improvements by applying a 1% frontier shift to DNO cost forecasts which in many cases have already allowed for efficiency improvements.

For example, EDF Energy already included in its FBPQ forecast a 0.5% reduction in aggregate operating costs. We are also aware that some other DNOs have also included efficiency savings, for example WPD. Where such a DNO sets the benchmark cost level (i.e. is a "frontier" company), the benchmark already includes efficiency savings expected to arise in the future. Applying a further efficiency improvement assumption will have the effect of double counting a proportion of potential cost savings.

Ofgem needs to determine the precise basis of the forecasts used in its benchmarking analysis and to correct the results for this type of error.

10. Losses Incentive

10.1. Use of RF settlement data

It is inappropriate to use RF data when superior DF data exists. DF runs are authorised by the Trading Disputes Committee because the RF run is considered not to be sufficiently accurate. If Ofgem are seeking the most accurate calculation of losses then this logically must involve the utilisation of the DF run.

The differences between RF and DF data can be large as adjustments are entered into settlements, often as a result of our data management activities. The table below sets out the percentage adjustments to losses for EDF Energy's DNOs in recent years and compares the movement between the initial run (SF) with the RF run, and between RF and DF runs:

DNO	SF to RF	RF to DF
EPN	0.34%	0.30%
LPN	-0.49%	0.18%
SPN	-0.17%	0.13%

Exposing DNOs to an incentive based on RF runs exposes them to an additional risk of late/early adjustments by suppliers to settlements data. Such a risk is unmanageable by DNOs and, therefore, weakens incentives.

We understand that using DF data would delay the time lag between regulatory year and the determination of incentive revenue. However, losses are a long term issue so this should not be a problem.

Ofgem should base its incentive on the final and most complete/accurate settlement runs whether that is RF or DF.

10.2. Losses incentive rate

Another key element of the losses incentive scheme is the incentive rate. Ofgem has calculated its proposed incentive rate by subtracting the historic average 2009 EU ETS price and adding the social price of carbon to the historic average wholesale price of electricity in 2009. We have a number of comments on this approach.

Ofgem's forecast of £60/MWh over DPCR5 is higher than the market's current expectation of the power price over that period. (see Table 3.1.) Given that the wholesale price of electricity determines the value of investments to reduce losses, Ofgem's current proposals may create inefficiently high levels of investment.

It is not clear what emissions rate (tonnes CO2/MWh(e)), or what measure of the 2009 wholesale price of electricity Ofgem has used in performing this calculation, making it non-transparent.

However, Ofgem's estimated social price of carbon comes from DECC's recently published "central" forecasts of the traded carbon price, which increases gradually from £21.3/tonne CO2 in 2009 to £25.1/tonne CO2 in 2020 (2009 prices).[3] This forecast is well above the current EU ETS price, which on 12 August 2009 was €14.31/tonne CO2 for 2009, rising to €16.65/tonne CO2 for 2012.[4]

DECC's publication notes that:

> "Observed market prices would be the best estimates of the traded price of carbon for the 2008-2020 period but this is currently not possible for the whole period because the forward market provide reliable prices only up to 2012. As discussed above, complementing observed market data with modelling estimates is likely to lead to significant jumps in the carbon price schedule. Further, observed market data are likely to be relatively volatile requiring very frequent updates if the data are to be accurate, potentially undermining the stability of the policy appraisal regime. The EU ETS market is rapidly developing with prices changing rapidly. While it is important that estimates are up-to-date, there are also important considerations in terms of the stability of estimates for appraisal guidance and the time-dependence of our policy assessments…On balance, for the reasons above a modelling based approach was exclusively used to derive the estimates of the traded sector for the 2008-2020 period rather than a combination of observed market data and modelling."[5]

DECC, therefore, accepts the primacy of market prices and only uses a modelling result to provide a stable result. Based on DECC's arguments, using DECC's long-term CO2 price forecasts as a planning assumption for the period to 2020 appears reasonable. However, Ofgem will only commit to an incentive rate for each regulatory period, i.e. out to 2015. For that period, forward market prices provide a reasonable basis for valuing savings, even if they are only available until 2013. The average forward market price in the Table below is £51.48 for the period from Summer 2010 to Summer 2013. To bring the average price over the next regulatory period (Summer 2010 to Winter 2014/15) up to £60/MWh, prices in the last eighteen months (Winter 2013/14 to Winter 2014/15) would have to average £80/MWh, which seems

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[3] Carbon Valuation in UK Policy Appraisal: A Revised Approach: Climate Change Economics, Department of Energy and Climate Change July 2009, Table 6.3.

[4] Source: Bloomberg.

[5] Carbon Valuation in UK Policy Appraisal: A Revised Approach: Climate Change Economics, Department of Energy and Climate Change July 2009, Section 6.4.

unlikely. Even if the pricing series were to continue rising in line with the trend in Table 3.1 (summer prices: 40.94, 47.30, 50.90, 55.34, **60.00**; winter prices: 50.45, 55.20, **60.24, 65.00, 70. 00**), the average over the period is only £55/MWh.

We believe that Ofgem should rely on market prices for medium term incentives and that such prices indicate a level lower than £60/MWh. Even DECC says there is no rationale for inserting the government's model results into such medium term forecasts. To avoid encouraging inefficient levels of investment, the incentive price should be closer to £55/MWh.

Season	Pricing Date	Forward Price (£/MWh)
Summer 2010	03 Aug 09	40.94
Winter 10/11	03Aug 09	50.45
Summer 2011	03 Aug 09	47.30
Winter 11/12	03 Aug09	55.20
Summer 2012	29 Jul 09	50.90
Winter 12/13	03 Aug 09	60.24
Summer 2013	30 Jul 09	55.34
Average		**51.48**

Source: Bloomberg

Note: The forward prices were valid as of 3 August 2009, although where prices were not available on this date, we took prices from the most recently available date before that. Forward prices are currently only available until Summer 2013.

10.3. Losses – target setting

Ofgem must set targets on the basis of what is achievable since otherwise this would amount to an unjustifiable denial of cost recovery (or possibly a windfall gain to the DNO).

We understand the sensitivity of this subject, particularly in relation to DNO performance in DPCR4. However, that review must be seen as a package, and in the case of EDF Energy gains from the losses incentive have been largely offset by costs disallowed through simplistic cost benchmarking.

On the basis of the description Ofgem provide in the Initial Proposals for a common reporting methodology we have forecast our expected losses at RF run for 2008/09 and 2009/10 using three scenarios and produced targets based upon the simple five year average over the DPCR4 period. We have then forecast our incentive performance in DPCR5 assuming that the 2009/10 performance level is held for the 5 years of the DR5 period. Our modelling produces a range of outcomes, all of which are negative (i.e. are penalties):

Forecast losses incentive (all figures £m for DPCR5 period)	Losses continue to increase	Losses level off	Losses trend reverses
EPN	-99	-67	-37
LPN	-54	-18	-15
SPN	-11	-9	-1
EDFE Total	**-164**	**-94**	**-53**

Setting targets in this manner clearly does not create an incentive where the potential risk and rewards available to a DNO are balanced. The trend in settlement derived losses is upwards and, therefore, additional weighting needs to be given to the most recent years when calculating an averaged target.

A simple approach to target setting using raw settlement data will unfairly penalise our leading role in the data management effort during DPCR4 (as Ofgem has previously recognised).

The levels, by which the penalty collars are exceeded in some of the above scenarios, by £45m in one case, make it impossible for any reasonable actions by EDF Energy to have any impact on the financial impact of the incentive because of the necessity to move settlement so far before reaching the collar. This is a risk that EDF Energy can not accept.

10.4. Data Management Costs

We are incurring c£5m of cost per annum across all three regions on data management activities in delivering our DPCR4 performance and we will have to spend similar sums in DPCR5 just to stand still because our past performance is built into targets. This is in effect a c£35m penalty, compared to the other DNO's, a penalty for being pro-active.

We discuss the impact of including these costs in the cost benchmarking above.

Our conclusion is that Ofgem should ideally adjust the Group 3 costs and provide EDF Energy with an additional cost allowance to cover our steady state costs of data management or alternatively build our data management activities into the targets by increasing them by 0.2% to reflect our first mover role in data management.

10.5. Losses – caps and collars

The size of the cap and collars proposed by Ofgem at 0.5% of units distributed equate to a similar level risk/reward as that arising from the Quality of Service

Incentive. This seems disproportionate considering the relative levels of influence that DNOs have over their own network (our core business) and national settlement – operated and run by suppliers and generators.

We understand that Ofgem does not want to find DNO's benefiting from windfalls and so we consider that a sensible way to deal with this would be tighter caps and collars.

We propose that cap and collars set at 0.25% is much more reflective of what a DNO can achieve providing sufficient incentive for data management activities whilst providing a shield against supplier data cleansing actions. In addition EDF Energy would be willing to accept an asymmetric incentive that constrained out performance to 0.125% - half the level of the penalty.

Our proposed approach

An approach to managing this would be to constrain the cumulative effect of the losses incentive during the period of its operation to be no greater than the overall cap or collar. This will counter the potential in year effects over the period of its operation which is likely to stretch into the DPCR7 before the final year of any rolling retention mechanism roles out. The nature of settlement is such that there could be large swings from year to year which will affect DNOs in terms of fluctuating cash flows and will affect customers in terms of the prices that they see.

An example of how this might work is shown below using the figures from EPN for the continuing trend scenario when once the effect of the collar bites (2015/16 in this case) the effect of the incentive is constrained by the cap smoothing the outcome on customers prices.

Year	2013/14	2014/15	2015/16	2016/17	2017/18
Relevant Year of Losses Incentive	2010/11	2011/12	2012/12	2013/14	2014/15
Performance	-19	-20	-20	-20	-20
Cumulative Performance	-19	-39	-59	-79	-99
Collar	-54	-54	-54	-54	-54
In Year Adjustment to Allowed Revenue	-19	-20	-15	0	0
Cumulative Adjustment to Allowed Revenue	-19	-39	-54	-54	-54

10.6. Losses incentive – conclusions

In conclusion we believe that Ofgem's Final Proposals should

- Use the most appropriate settlements data to set targets by setting targets using DF data and weighting the calculation towards recent years
- Recognise our first mover data management activities during the DPCR4 period
- Balance of probability is that the downside risk to us is greater than the potential benefits but acknowledging Ofgem's needs to protect customers and set an asymmetric constraint to the incentive – collar our risk at -0.25% and cap the exposure to customers at +0.125%
- Protect both Customers and DNOs from volatility in the incentive
- Set targets based upon DNO's estimates with a truing up once final DF data is received and constrain the cumulative impact of the Losses incentive to the total cap/collar amounts through DPCR5/DPCR6

10.7. Losses - Rolling Retention Mechanism DPCR4

The Initial Proposals document sets out ideas for the completion of DPRC4 loss incentive calculations – the Rolling Retention Mechanism (RRM). These are very different from EDF Energy's understanding of what was agreed in the Final Proposals for DPCR4. Despite this the operation and implications of this process are made no clearer than before. This presents a very great degree of uncertainty, the impact of the RRM could be extremely significant to the overall DPCR5 outcome and clarification is urgently needed.

Within the Initial Proposals document two different RRM calculations are implied or suggested, both would give extremely different outcomes:

- Data calculated using the model from the March Environmental Working Group document is quoted in table 7.1.
- Paragraph 7.11 suggests that the model from the original DPCR4 proposal would be used.

The Environmental Working Group calculation is flawed in that it does not ensure the only objective of the RRM, stated in the DPCR4 Final Proposals (Page 147, Para A1.35 point 6) that

> "*DNO's keep the benefit and penalties of performance against the losses target for five years through the application of a rolling retention mechanism*".

Under this model there is no guaranteed link between the total penalty/benefit and the total performance over 5 years. The RRM calculation effectively ignores years 2-4 and calculates the post DPCR4 outcome on the movement between years 1 and 5. We have modelled a number of possible interpretations of what Ofgem has proposed within the Initial Proposals and within subsequent meetings of the Environmental

working group. Using our mid case scenario, where losses outturn is assumed to be constant from 07/08 onwards, we are predicting a significant claw-back in DPCR4 under each of our scenarios.

DPCR5 Earnings (losses) DPCR4 RRM (£m 08/09)

	Ofgem IP	Losses rephased to 08/09 & 09/10	Losses rebalanced to actual year
EPN	-£135	-£72	-£63
LPN	-£38	-£18	£3
SPN	-£27	-£2	£0
EDFE	-£199	-£92	-£60
Avg Earned Per MWH	*-£11.8*	*£24.2*	*£34.9*

These scenarios have a significant impact on the implied losses incentive rate within DPCR4, with all three significantly below the target rate of £48/MWh (02/03 prices).

The calculation in the DPCR4 proposal does not share the same inconsistencies and volatility (though it was not defined adequately), as it takes average performance to calculate the roller outcome. The proposal to add latter settlement data to this calculation would give a more accurate picture and eliminate differences caused by reporting methods, but by waiting for the settlement process to unwind, it will also add another significant element of uncertainty, one which the DPCR4 Final Proposal document did not allude to.

To make meaningful comment about opting/buying out of the RRM is almost impossible without first agreeing the roller mechanism. The level of uncertainty surrounding settlement data would also make decisions on whether to opt out or buy out extremely difficult and full of risk.

Our legitimate expectation is that the losses roller should continue into DPCR5 except that no new year's data enter the calculations beyond 2009/10. Any departure from this would, we believe, represent a claw-back of incentive rewards which would significantly increase regulatory risk and the cost of capital.

11. Other Incentives and Obligations

11.1. Low Carbon Networks Fund

The Low Carbon Networks Fund (LCNF) is a interesting initiative and has our full support. With improvement (see below) it could provide a very positive stimulus for DNOs to extensively trial, in a relatively low risk environment, the new technologies, network architectures, commercial contracts and business models that will need to be put in place to support (and as a consequence of) the UK Low Carbon Transition Plan and Renewable Energy Strategy.

EDF Energy is well placed to develop, with the required collaborative partners, project proposals that would be suitable for bidding into the proposed £360m central fund. In particular, AuRA NMS and FENIX, both developed under IFI, would be suitable concepts to now develop now into full scale field trials, while a number of supporting technologies (such as Fault Current Limiters) could continue to be developed with further funding either as IFI projects or 'Tier 1' LCNF projects (EDF Energy's entitlement being around £18m over DR5).

There is however a need for further clarification on the proposed working of the competitive tendering process. DNOs, and their collaborative partners, will incur considerable expense in developing project proposals to a level suitable for bidding into the central fund and it will be important that Ofgem quickly and clearly sets out its expectations in terms of the 'pro-forma' documentation; i.e. in terms of the information and analysis required to support the proposal and, in particular, the 'success' criteria against which competitive bids would be assessed.

Care must also be taken to ensure that the 'competitive' aspect of the bidding process does not dissuade companies from sharing information, or even collaborating to develop prospective bids; clearly there is significant merit in ensuring a co-ordinated approach by DNOs, in terms of avoiding the possibility of duplication of proposals and/or a poorly balanced or disjointed overall portfolio of projects. Co-ordination will be particularly important for developing common procedures to identify and appraise these innovative projects.

One particular area for concern is the proposed treatment of intellectual property rights (IPR). Development and retention of IPR is a key incentive for vendors of network components, ITC and control systems. While sharing of information is an important deliverable from the LCNF, this benefit should not extend to sharing IP which would remain quite properly with the equipment vendors who develop the hardware/software etc. and who contribute to the project in terms both of expertise and product development.

11.2. LCNF – Incentive properties

The scheme has few incentive properties and therefore, if carried forward to the Final Proposals in its current form, is unlikely to succeed.

The requirement that DNOs "fund" at least 10% means the DNOs will only invest if additional revenues or cost savings are expected to arise from other sources. However, Ofgem has effectively closed off two possible sources of revenue through the design of its proposed LCN scheme:

- £100m discretionary reward: The partial funding of schemes will not be offset by the opportunity for DNOs to earn a return on investments made under LCN-funded schemes through a £100m discretionary reward. The fact that this reward is discretionary, i.e. there are no published criteria for making awards, means any returns available from LCN schemes are effectively random. A lottery that promises to give punters either their money back or nothing will not attract many entrants.
- Retention of benefits: Under the current proposals, the shortfall in direct funding will not be offset by DNOs capturing some of the benefits created by LCN-funded projects. DNOs cannot benefit from retained intellectual property rights and Ofgem has even stated its intention to deny cost recovery for a larger share than 10% if there are any identifiable benefits. (93/09, para. 1.9.). Such an uncertain incentive mechanism is unlikely to be attractive to prospective research partners and could seriously compromise the quality (or adventurousness) of project proposals, to the detriment of advancement of corporate learning.

These policies are simply inconsistent with the desire to provide an incentive for innovation. To remedy the error, Ofgem should do two things;

- Set out clear rules for the discretionary reward fund
- Permit DNOs, vendors etc to retain IPR

Ofgem should also give up the attempt to micro-manage innovations by reducing available funding every time there is any discernible benefit. If Ofgem sets out criteria for funding a fixed proportion of costs, DNOs will then have an incentive to seek out the innovations likely to be most beneficial. Ofgem may have to increase the proportion of funding above 90%, however, if DNOs cannot see a way to retain benefits.

11.3. Information Quality Incentive

We note that Ofgem has strengthened the IQI incentive rates from those presented in the May methodology document (i.e. the GDPCR matrix), is considering strengthening them further (as set out in Figure 19.3), and could change them even further depending on the specification of the rest of the price control package (para 19.26).

We find this very hard to understand. The IQI is an incentive designed to encourage accurate cost forecasting. But since the DNOs submitted their final forecasts in June of this year, changes to the incentive will have no impact on the DPCR5 forecast, but will instead only muddy any incentives Ofgem wishes to offer in future reviews. For example, when DNOs are preparing their forecasts for DPCR6, they will have no idea what incentives will be in operation since Ofgem is likely to change them ex post in order to calibrate the overall price control package. It is hard to see how this can be an approach consistent with the principles of better regulation. The proper conduct of the price control review requires that Ofgem abides by any incentives offered to DNOs. Otherwise the process makes a mockery of the whole attempt to offer incentives for efficient behaviour.

12. Connections

12.1. New Guaranteed Standards of Performance

Proposed licence condition

Ofgem's proposals to put in place a quarterly overall performance target (initially a 90% success rate against more onerous standards) is unacceptable to EDF Energy on the grounds that taken together with the new target achievement times:

- It is a more onerous standard than we are working to currently (particularly regarding the UMC standards); and
- It will take cost and time to achieve the standard. EDF Energy cannot accept a new licence obligation in the knowledge that there would be a high probability of immediate breach. In any case, Ofgem has not provided any funds for achieving these new standards immediately.

Adding a licence condition is in any case unnecessary since a strong incentive is already provided by the financial cost to the DNO of each failure. Introducing a double-jeopardy of the sort being proposed would be disproportionate.

Unforeseen consequences

We are concerned that a regime of targets will have untended consequences for customer service. For example, the arrangements for commencement and completion of works could severely reduce the DNOs ability to 'fine tune' programmed dates in a manner most likely to meet the requirements of customers in general (i.e. customers not ready for DNO works to be carried out on the programmed date would go to the back of the queue).

12.2. Implementation issues

EDF Energy is also concerned at any suggestion that the new standards should come into force at the start of the DPCR5 period at 1st April 2010. Such a short time allowance is inconsistent with that provided for other initiatives. It would be more sensible to allow the introduction time scales to be aligned with those that Ofgem has proposed for the introduction of the new "overall measure of customer satisfaction" (including customer satisfaction surveys).

EDF Energy would urge Ofgem to streamline the package of new standards to a level that is likely to be workable in practice and provide customers with confidence concerning only the essential key steps of the connections process.

We believe that if the introduction of such a comprehensive new standards regime is not handled carfefully, there will be significant disruption to normal business activities and resultant levels of customer service. For this reason it is imperative that time is allowed to specify, procure and deliver the necessary IT systems. Also,

sufficient time needs to be allowed to design new business processes, train staff and advise customers of the changes.

Whilst EDF Energy has already started this work, it cannot complete even the IT specification works until final details concerning the standards are known, including detailed definitions, any exemptions and business rules associated with their application. EDF Energy would propose that the time scale for introduction of any new standards is 1st April 2011.

EDF Energy is concerned that the consolidated concerns raised by the ECSG DNO representatives have not been reflected in Ofgem's Initial Proposals. These concerns were provided to Ofgem in email communications dated 19 May and 5 June 2009 and are reflected in this response.

We note Ofgem's intention for the standards to be voluntarily applied and payments made to customers other than the end user.

We also understand it has been suggested at the ECSG that the standards should be applied to services under SLC15. However, we would point out that the services provided under SLC15 are significantly different from those to be provided under the proposed standards and it is difficult to see how the two sets of requirements could be aligned.

As presently drafted both the service standards and the competition tests are ambiguous and require much further work on definitions and exemptions etc. It is noted that the ECSG will need to iron out a number of inconsistencies in the documentation and achieve a set of standards that are likely to be effective across the complete range of connection scenarios.

We have serious concerns regarding the uncapped nature of the payments regime. We believe it is appropriate for a cap to be applied to the number of failure days attributable to any particular standard (e.g. 5 – 10 days). Whilst DNOs will always seek to act in good faith it is possible to imagine circumstances where a relatively minor omission or data entry error by a DNO employee could be made on a project where the customer is either not ready to receive the service or the project is deferred or even cancelled (and hence the customer does not urge the DNO to provide the service) which results in a very large payment being attributable. We do not believe this situation should be permitted within the standards regime.

We believe that assessment against any percentage threshold under the licence condition should be made on an annual basis as for existing licence condition 15.

12.3. Comments on proposed standards

Budget Estimate

As part of streamlining we believe that this standard should be removed. We understand that most DNOs presently provide budget estimates without charge and within timescales that will allow a meaningful estimate to be provided.

Quotation

In general EDF Energy supports the introduction of the quotation standards as a means to provide defined timescales to operate alongside the 'as soon as is reasonably practicable' requirements of SLC12.

However, we do have some concern that it may not always be appropriate for a shorter time scale to apply to an LV scheme. Demand information is normally not available 'on file' for the existing LV network and it is often necessary for temporary demand monitoring equipment to be installed on site in order to gather such data. It is important for time to be allowed for an LV option to be fully explored before moving to specify an alternative HV connection.

Ofgem is aware of the work that EDF Energy has recently completed in order to make customer service improvements for works in the '< 5 plots' category (Project ICE). We believe it will be important for the clock start, pause and stop events to be defined appropriately for this category of work.

Contact Customer

We do not believe that the contact customer standard is either necessary or workable across the full range of connection types. For projects work it is entirely probable that the customer will not be in a position to discuss dates at such an early stage after acceptance of the quotation and on this basis the proposed arrangements are unworkable.

Further, it will sometimes be the case that quotation acceptance will mark the start of work to finalise cable routes (route proving) and to obtain any third party permissions or consents. In such cases it will not be possible to arrange work dates at this stage.

In many cases it is normal practice for the DNO to visit site in order to discuss the construction programme with the customer and arrange dates for the work to be carried out. At such a site visit it will normally only be possible to discuss dates for the initial phases of the works and not for all the works.

With the possible exception of work in the '<5 plots' category it would be more appropriate for there to be no defined requirement to contact the customer within any particular number of days.

For other work categories it would be more appropriate for the requirement to be for the DNO to contact the customer to provide details of whom to contact when they are

ready for works to be programmed, with phone numbers etc. provided. In the interests of streamlining the standards it is considered unnecessary for any time scales to be attributed to this action as it should normally be a standard DNO response to the acceptance of the quotation.

We believe that it is only appropriate to arrange programmed work dates when the customer is ready for them to do so. This will result in an added benefit that it will be less likely for the customer to subsequently wish to change the dates than otherwise would be the case.

Commence Works

In the interests of streamlining we believe it is unnecessary for a standard to apply to the commencement of works.

Complete Works

We agree that a standard should apply to the completion of works.

UMC faults

Over recent months EDF Energy has made all reasonable endeavours to deliver significant improvements to its performance under the existing Voluntary SLA for UMC work. However, we have not been able to fully achieve the SLA standards and are unlikely to be able to do so by 1 April 2010. For this reason we cannot agree to imposition of this new mandatory standard.

We would also urge Ofgem to recognise the importance of setting any incentives for prioritisation of UMC fault repairs at an appropriate level in comparison to other fault repairs on the distribution system as a whole.

UMC new works quotation

In principle we support the introduction of this standard but only if the original SLA volume is restored. It is unreasonable that the number of units has increased up to 100 without any apparent justification or logic.

UMC new works commence and complete works

In principle we support the introduction of this set of standards but only if the original SLA volumes are restored. It is unreasonable that the number of units has increased up to 100 without any apparent justification or logic.

Recovering the costs of new obligations

Ofgem's proposals regarding connection work outline a number of new obligations it would place on DNOs. These new obligations will increase DNOs' total costs of carrying out connections work. However, as far as we can tell from Ofgem's Cost

Assessment consultation, it has not taken account of these extra costs in setting its "baseline".

We believe that systematically obliging DNOs to conduct more work (or conduct work to a higher standard than before) without increasing allowed costs would be in breach of the Authority's financing duty.

12.4. The application of connection margins

Ofgem has also indicated that it will allow DNOs to earn a margin on connections work in an attempt to encourage competition in the provision of connections. Ofgem's Initial Proposal for the allowed connection margin of 4% draws on NERA's January 2009 report. In particular, Ofgem uses figures for margins defined as:

$$\frac{\text{(Net Operating Income + Fixed Asset Depreciation and Amortisation)}}{\text{Net Sales}}$$

Ofgem's proposals state that:

> "Respondents should note that for simplicity no margin will be allowed on the indirect costs associated with connection charges and so the margin has been proposed at a level that takes account of the associated indirect costs."

The margin defined above is essentially operating profit (in £m), after deducting overhead costs and expenses (or "indirect" costs), but before deducting depreciation and interest costs:

(Total Direct Costs + Total Indirect Costs) / (Total revenue) = 1 + Margin (%)

Applying the 4% margin only to "direct" costs would be inconsistent with the data NERA presented in its January 2009 report. Ofgem relies on that report for its proposed connection margin – but that data applied to both "direct" and "indirect" costs. Ofgem should therefore continue to follow its proposed approach, but in a consistent manner, by scaling up the margin by the average DNO ratio between direct and indirect costs.

13. Network Output Measures

There should be sufficient flexibility in any ex post review such that a DNO has an option to 'make the case' for an element of outturn underperformance where this would be preferable to an inefficient attempt to recover an adverse trend in performance over the remainder of the current price control period. Such an approach would be far preferable to a deterministic 'pass/fail' mechanism applied to each individual output.

Moreover, there has to be scope for a DNO to use reasonable judgement in the event that condition degradation/failure trends exceed expectations through no fault of the DNO. While DNOs must be prepared to carry most of the asset health risk, it would not be in any party's interests (least of all customers) for DNOs to attempt to recover every adverse trend irrespective of cost. It might for example be possible, and preferable, to mitigate the *consequences* of an adverse trend (including the customer impact) and/or it might be that the trend suggests a new longer-term asset management strategy.

Indeed, one of the potentially most valuable outcomes of the outputs regime is that both DNOs and Ofgem will be better informed approaching the end of one review period (DPCR5 in particular) to determine efficient investment levels and priorities over the following review period(s). That benefit could be seriously undermined by an obligation which encouraged a 5-year period target-based approach to network investment and which resulted in inefficient short-term asset risk management strategies that proved more costly to customers in the longer run.

14. Transmission Exit Charges

Overall, we are disappointed that Ofgem has not taken on board our views and those of other DNOs that this is not a suitable area for the development of incentives. We continue to consider that the exiting arrangements offer sufficient incentives for both parties to minimise costs without any need for an artificial "incentive" to encourage companies to do what they already do.

If an incentive regime is to be introduced then it should be limited to those assets that are related to DNO initiated demand driven reinforcement schemes. It is unreasonable for DNOs to potentially be penalised for reinforcement driven by National Grid's changes to the transmission system.

An incentive scheme would also expose DNOs to increased risks associated with the 'lumpiness' of costs associated with new exit charge schemes and the impacts of any changes to National Grid's Connection Charging Methodology.

Finally, EDF Energy provided some initial feedback on Ofgem's Initial Proposals document on 11 August 2009. This feedback related to an analysis of the table published on page 93 of Ofgem's initial proposal document 94/09 which included a number of discrepancies from EDF Energy's final submission and answers to Ofgem's supplementary questions:

- The figures do not take account of our 15 July 2009 update paper.
- The figures quoted for incentivised costs for SPN match neither that submitted by EDF Energy in June or in our 15 July Update.
- The figures include the assumption that all of the costs of schemes already committed to by EDF Energy, where National Grid have placed contracts and construction works are underway, are fully controllable by EDF Energy Networks.

Applying the combined effect of our 15 June and 15 July submissions and removing the costs associated with schemes already committed to by EDF Energy, where National Grid have commenced work provides a realistic view of the costs that EDF Energy may have influence over. These are:

£m	2010/11	2011/12	2012/13	2013/14	2014/15	Total
EPN	0.0	1.1	1.1	1.1	1.1	4.4
LPN	0.0	0.0	0.9	1.2	3.9	6.0
SPN	0.0	0.0	0.0	3.1	3.1	6.2

15. Cost of Capital

15.1. Ofgem's process

We note that Ofgem intends to continue with its traditional approach of using historic market data to inform its views on the Weighted Average Cost of capital (WACC).

At the highest level we have no issue with this approach. The devil, as always, is in the detail – and in this case, how the approach is used in the context of how the financial markets will behave in the future compared to the reference date used to inform Ofgem's estimate of the WACC.

We focus on five key areas in this section:

- Choice of historic data – what is the best fit for the post credit-crunch environment – and particularly, how Ofgem can ensure that it is not just modelling unsustainable "bubble" conditions?
- Cost of equity – returns required post credit crunch have increased
- Investor sentiment - Understanding how investor sentiment has changed.
- Dividend Growth Model (DGM) - Use of the DGM as a cross check on Ofgem's estimates.
- Relative risk – we have already set out our view that risk, including regulatory risk, has increased with the Initial Proposals.

15.2. Choice of historic data

Ofgem has chosen to base its Analysis on the period from January 2000 to the present, and for Index Linked Gilts produced the following yields across a range of maturities:

Maturity	Average Yield 2000-2009
5 Year	2.1%
10 Year	1.9%
20 Year	1.7%

However, historically there are very low values. Indeed, taking different time windows has a significant impact on the outcome:

Time period	Average Real Yield
Last 10 years	1.92%
Last 20 years	3.00%
Last 30 years	2.88%
Last 40 years	2.09%
Last 50 years	2.29%

Note that the above data is the yields on Consolidated Stock (for which a longer data series is available), but which exhibits a close fit to the performance of gilts.

The data shows considerable variation (56%) depending on the choice of "window"

Ofgem needs to address the following question

- Is 2000 to 2009 the right window to look through to see how the markets will behave in 2010 to 2015?

Most commentators point to a period on unsustainable behaviour in the lead up to the 2008 collapse strongly suggesting that this period is not a reliable guide.

We are unsure as to whether Ofgem has appreciated this point. There are signs that it has not:

- The question is not raised in the Initial Proposals
- Ofgem's quotes its past cost of capital decisions (the last one of which (the GDPCR) late 2007.

The 2000 to 2009 data has also been distorted by an FRS17 driven increase in the demand for gilts by pension schemes. In the early 2000s this depressed index-liked yields as demand outstripped supply. However, it took unti 2007/2008 for the Treasury to respond to the demand

More recently, the short term (hopefully) policy of quantitative easing will make price data unique and unreliable for forecasting – suggesting that any recent movements cannot be cited by Ofgem as evidence of a return to "normal".

15.3. Cost of equity

Ofgem comments that Utilities have outperformed the FTSE100 since the onset of the crisis. However, we note from the most recent data that the gap has closed somewhat.

There is evidence that the cost of equity has increased during the crisis period, for example FTSE100 yields have risen. Indeed, we believe that infrastructure funds are

now targeting returns of around double their pre-crisis levels (because such cash-rich investors have become such a scare resource).

However, the key question for Ofgem is what the post credit crunch period will be like.

We believe that there will be a re-pricing of financial risk, reinforced by regulatory driven structural change to the markets. What the balance between regulation and unrestrained market activity will be is difficult to predict; but it is easy to predict that the systematic under-recognition of risk seen in the pre-crisis period is unlikely to return in full.

On this basis, historic equity returns (and particularly those seen in the liberal conditions of post 2000) are unlikely to return – and unlikely to be allowed to return. The solution in this environment of uncertainty is for Ofgem to listen to what investors are saying. There are two important ways of doing this:

- Increase the weighting given to dividend growth model results
- Increase the weighting given to investor surveys.

15.4. Investor sentiment

The Energy Networks Association (ENA) has commissioned Indepen to carry out its first ever investor survey, the results of which are expected to be submitted to Ofgem in the coming weeks.

Water UK has been carrying out such surveys from a number of years, and is due to complete its survey during September. It will be important for Ofgem to take account of what water investors are saying because the pool of traded DNOs is so small (essentially SSE).

Water company share prices have continued to fall since the publication of Ofwat's Draft Determinations at the end of July, while the UK stock market as a whole has risen.

The chart below shows the evolution of water market to asset ratios for the four listed Water and Sewerage Companies (WaSCs). The estimates are approximate because it is difficult to adjust for unregulated business.

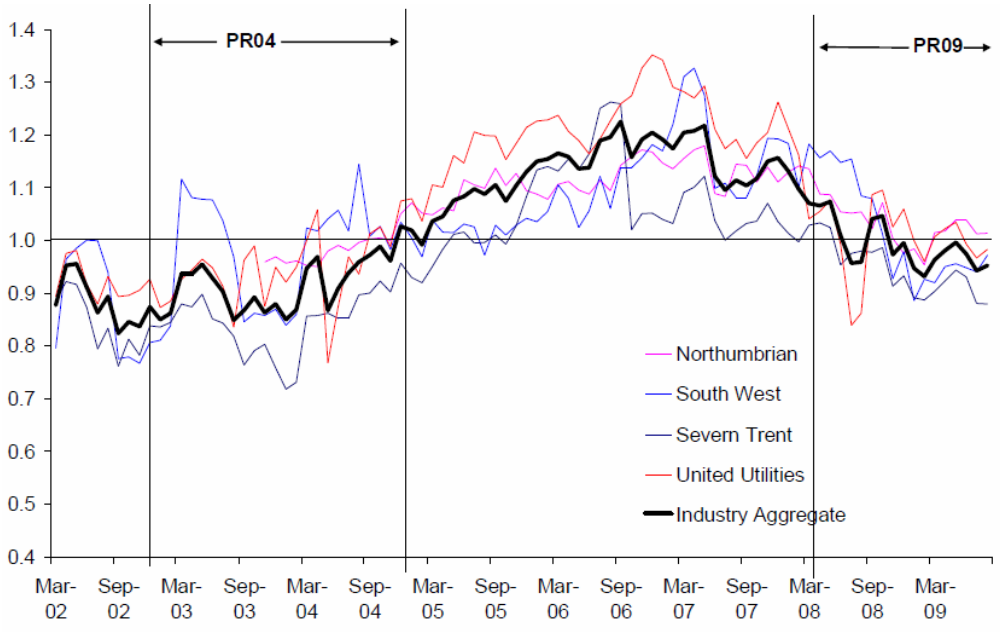


Chart shows market value of equity plus market value of net debt (regulated activity only) divided by RCV.

The indicative MARs have been falling throughout the PR09 discussions. By the end of August 2009 (i.e. after the publication of the draft determinations on 23 July) the weighted average MAR for the four stood at 0.95.

MARs below zero are suggestive of investors expecting returns below the cost of capital - either because of the forward looking aspects of the PR09 review, and/or because of the truing up of PR04 incentive/revenue mechanisms.

Ofwat, like Ofgem, also seem to have based its cost of capital work on a return to pre-crisis "bubble" conditions. Certainly, the publication of Ofwat's views on the WACC have done little to raise investors' expectations of the sector, suggesting to us that the package is inappropriate for current market conditions and sentiment.

In this context the range proposed by PWC for Ofgem (3.0% to 4.85%) lacks credibility.

15.5. Dividend Growth Model (DGM)

In its report for the ENA, NERA has provided DGM-based estimated of the equity risk premium in the range of 7.2% - 9.5% - around 3% higher than pre-crisis estimates of 5.4%.

The detail of NERA's analysis is already with Ofgem and is not repeated here.

Clearly, DGM estimates will evolve over time as everybody's understanding evolves of the enduring post-crisis trading and regulatory environment. Therefore, we would not expect to face an ERP at the top end of NERA's estimate taking the DPCR5 period as a whole. However, stabilisation at the mid-point seems a real possibility.

15.6. Relative risk

We note that Ofgem's final decision on the cost of capital will be informed by an analysis of relative risk.

We believe that the Initial Proposals increase risks, mainly though the additional regulatory risk stemming from opaque and subjective approaches to cost assessment.

15.7. Cost assumptions underlying the financeability tests

Although the Initial Proposals do not say so explicitly, Ofgem appears to have conducted its financeability tests on the assumption that DNOs do not incur those costs which Ofgem has disallowed, due to benchmarking analyses which suggest they are "inefficient" or "imprudent". We do not believe that this approach fulfils the Authority's statutory duty to ensure licensees can finance their licensed activities.

Financeability tests act as a reality check on regulatory proposals, testing whether allowed revenues are high enough so that "the gearing level throughout the period, and the ability of companies to pay their interest obligations from their cash flows, are consistent with a comfortable investment grade credit rating." However, for financeability tests to act as a reality check, they must be realistic.

The conclusions of a financeability test that assumes companies will not incur disallowed costs would be meaningless. Disallowing costs means preventing the company from including them in revenues; it does not mean that the costs disappear.

If Ofgem has proof that DNOs' costs are currently above an "efficient" level, it may decide not to include them in revenues, with immediate effect. However, the Authority's financeability duty means Ofgem must still accept that DNOs will take time to reduce actual costs to the "efficient" level.

Ofgem cannot therefore avoid the need to set out a "glide path" for expected *actual* costs, even if Ofgem only *allows* DNOs to recover "efficient" costs from the start of the regulatory period. Incidentally, Ofwat recognises that it takes a number of years to reduce costs by allowing companies several years to close the gap between companies' current costs and its estimated frontier.

15.8. Required investment grade

According to Ofgem's initial assessment of DNOs' financial profiles for 2010-15, all the companies are consistent with a "comfortable investment grade". Ofgem claims this standard does not necessarily require an A grade rating. Leaving aside the error in Ofgem's cost assumption, this view of debt rating contradicts the Competition Commission's (CC's) recommendation in the recent Stansted review, where the CC concluded that a rating of BAA1/BBB+ would be insufficient in current market conditions:

"Given that there was an inevitable degree of uncertainty about the way that debt market conditions will evolve in the coming years; this suggested to us that an efficiently financed company might seek to target an A3/A– rating in the current market climate."

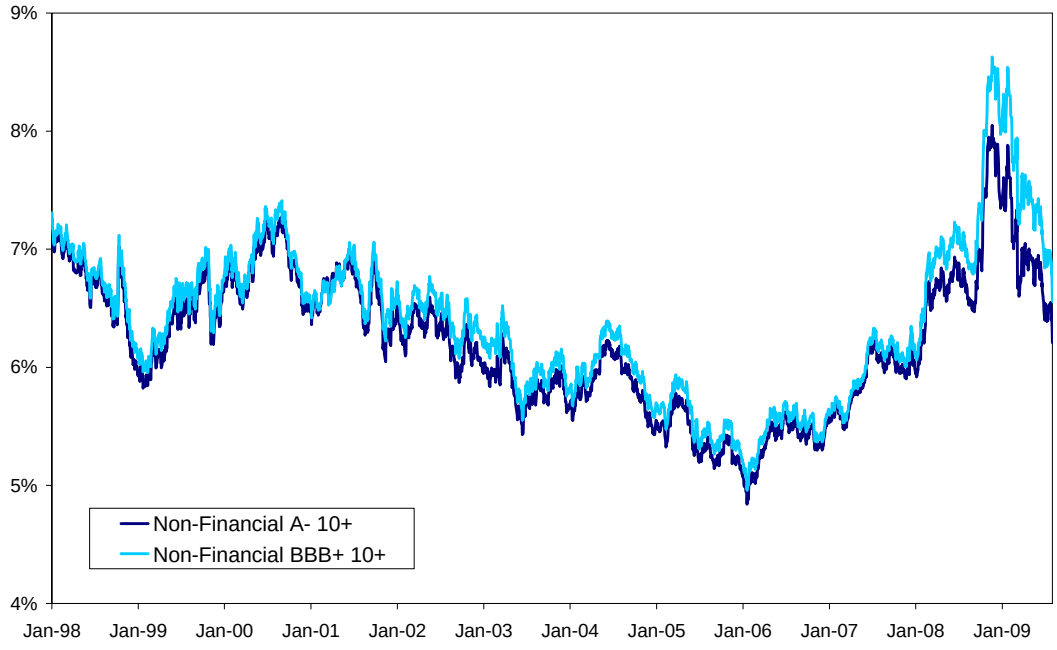
The CC therefore took the view that the allowed return should enable Stansted to obtain an A grade rating.

In its recent draft determination, Ofwat tested the water and sewerage companies against key financial ratios which are consistent with an A category. Ofwat suggested that investors in utility debt are "less sensitive to the difference between a high BBB and low A range ratings". However, Ofwat's statement is contradicted by a recent report by S&P on the UK Water sector in which S&P observes that investors have a clear preference for 'A' rated bonds:

"Recent bond issuance suggests [...] investors' preference for debt rated in the 'A' category."

In other parts of the report, S&P refers to Ofwat as being "relatively relaxed" for not making a distinction between A- and BBB+ rated debt. As the chart below shows there has recently been a significant widening between the costs of single A- and BBB+ debt.

Figure X.X
Secondary market bond yields



Source: NERA analysis of IBOXX data until 31st July 2009. A- and BBB+ series derived from A and BBB series using linear interpolation.

In particular, we note:

- Over the past ten-years yields on A- rated bonds have been about 20 bps less than yields on BBB+ rated bonds;
- More recently the differential has increased to about 50 bps.

NERA's review of recent city comments shows that in the current market environment, investors do make a distinction between A- and BBB+ rated debt.

The significant widening between the costs of single A- and BBB+ debt means that it is vital that regulators make clear what credit rating assumption is implicit in the cost of debt allowance.

We therefore conclude that to ensure Ofgem conducts a realistic assessment of DNOs' ability to finance their ongoing operations, it would be imprudent for Ofgem to consider a BBB rating category for DNOs in the current market environment when conducting its financeability analysis.

15.9. Financial ratios

As part of its financeability test, Ofgem examines three financial ratios. However, rating agencies and other UK regulators including Ofwat use a broader set of ratios (see Table 4.1) in order to assess companies' financeability more comprehensively.

Moody's and Ofwat focus primarily on '*adjusted*' cash interest cover ratios ("Adjusted ICR"). Adjusted ICR is calculated to measure the interest cover after deducting from cash flows the portion of the capital expenditure that is required to maintain the regulated asset base at a constant value over the regulatory period. The reason for this is that only cash after maintaining the business' operations is available to make interest payments *on a sustainable long-term basis*.

Ofgem however only looks at the cash interest cover ratio before capital maintenance requirements, which provides a very short-term view of companies' financeability. In particular, since DNOs' capex is to a large extent non-discretionary (due to environmental, legal or regulatory requirements), Ofgem should also consider *adjusted* ICR in addition to ICR as a key financeability test.

Key Financial Ratios used in Financeability Test: Comparison of Ofwat with Ofgem

	Ofwat (Draft Determinations, PR09)		Ofgem (initial proposals, DPCR5)
	Large Companies	***Small Companies***	
Cash interest cover (FFO : net interest)	~3.0x	~3.5x	3.0x
Adjusted cash interest cover (FFO less capital charges : net debt)	~1.6x	~1.8x	*not considered*
FFO : debt	~13%	~17%	*not considered*
Retained cash flow : debt	~8%	~10%	9%
Gearing (net debt : regulatory capital value)	<65%	<60%	65%

Source: Ofwat, DD PR09 (23 July 2009) and Ofgem initial proposals DPCR5[94]; Note: "Large companies" are water and sewerage companies; "small company" are water only companies.

16. Tax Response to Ofgem's Initial Proposals

16.1. Corporation Tax Allowances

At a high level, we believe that Ofgem's methodology is reasonably fair. However, there remain some important issues that need to be resolved.

16.2. Tax trigger: impact on the cost of capital

We believe the impact of any such effect would be small. In competitive markets a change in tax legislation which affected an entire sector would simply raise prices rather than impact profitability. Indeed, given the extraordinary state of the UK Government's finances, tax increases are more likely to be economy wide rather than fall on a particular industry. Such changes would have no affect at all on the DNOs' cost of capital.

In any case, substantial levels of risk would remain. In particular, DNOs would still bear the risk arising from changes in case law, changes in HMRC interpretation and the tax effect of changes in accounting standards, as well as the risk of tax changes that fall below the trigger.

16.3. Company specific compared to common allocation basis

EDF Energy maintains its position that company specific is the most appropriate approach to allocating capital .

16.4. Capital Allowance Percentages

EDF Energy appreciates the steps Ofgem has taken to increase the number of cost categories to which capital allowance percentages are being applied and to improve the accuracy and fairness of the process of calculating capital allowances. However, it is still the case that there is not enough granularity to provide fair allocations of capital allowances. All the information to provide the improved level of granularity that Ofgem refers to in the Initial Proposals is already with Ofgem.

16.5. Modelling IFI and the Low Carbon Networks Fund

Currently Ofgem's financial model assumes that all incentives are funded pre-tax and hence should be specifically excluded from the calculation of the tax allowance to ensure that no tax allowance is given on top of this. This is correct. However this treatment has also been applied to IFI and the Low Carbon Networks Fund.

The Low Carbon Networks Fund will provide support to DNOs to develop new technologies etc. that will reduce the overall carbon footprint of the networks. Rather than acting as an incentive, the fund is a contribution towards costs. The costs that the DNOs have forecast they will incur have been treated as deductible in the Ofgem's model but receipts from the fund have not been taxed. This does not mirror

reality and understates the DNOs' tax liabilities and hence understates the tax allowance.

Like the Low Carbon Networks Fund, IFI acts as a contribution towards costs. To ensure that the DNO is correctly modelled as getting a tax deduction for the net expenditure incurred the receipt of the contribution must be treated as taxable and hence not excluded from the calculation of the tax allowance as is currently happening.

16.6. Desirability of a tax trigger mechanism

Compared with five years ago there is considerable uncertainty about how, and at what rate, the DNOs will be taxed. The need to fund the increase in national debt leaves whichever Political Party is in power for the next price control period with difficult decisions to make over whether to raise taxes to try to increase tax take or whether to lower tax rates in order to provide stimulus to the economy and hence as a result increase tax take.

As a result of this uncertainty EDF Energy agrees with the proposal to establish a tax trigger mechanism. This mechanism is fundamental to a DNO to be able to accurately forecast future cash flows and raise the appropriate finance accordingly.

16.7. Scope of the Tax Trigger

Ofgem has proposed a trigger mechanism that will respond to changes in underlying tax legislation but which will not respond to changes in case law, HMRC interpretation, and changes in accounting standards that have a knock-on effect on the quantum or timing of taxation. Ofgem has however expressed a willingness to consider the effects of changes in case law and HMRC interpretations.

EDF Energy has previously expressed its views on the inclusion of changes in case law and HMRC interpretations. All that needs to be added at this stage are two points:

- if these are not included in the mechanism then the cost of capital needs to be increased to reflect the increased risk compared with five years ago, and
- a mechanism that only responds to one out of four clearly identified means by which DNOs' cash tax charges can be affected is quite arbitrary.

Ofgem has not yet publicly acknowledged that there can be major changes in the timing or quantum of taxation that can arise from changes in underlying accounting standards that are outside the control of the DNO. It is worthwhile giving an example of the kind of situation where this could occur:

- In July 2009 the Accounting Standards Board announced that UK GAAP would be withdrawn by as early as 2012 and replaced by the mandatory use of International Financial Reporting Standards ("IFRS"). Whilst UK GAAP and IFRS

largely mirror each other there are areas where there are differences. One area where there is currently considerable uncertainty is around IFRIC 18 and its application to customer contributions. There currently is debate around how IFRIC 18 would apply and under one view it could lead to acceleration of recognition of profits for accounting purposes and as a corollary lead to an acceleration of taxation. It is not expected that this uncertainty will be removed by the time Price Control Period 5 commences and it is of course this uncertainty that drives the potential tax risk. This potential acceleration of taxation would purely arise out of a change in underlying accounting – for most DNOs including EDF Energy, this would result from a change of GAAP but it would also affect those DNOs already using IFRS in that there would still be a change in the timing of recognition of profits. Clearly this timing of recognition would be outside of the DNOs' control.

16.8. Measurability

Ofgem has listed five key criteria by which it believes the trigger mechanism must operate. These have largely been paraphrased from EDF Energy's previous responses. However, there is one additional criterion: that the trigger mechanism is measurable by Ofgem with minimal recourse to DNOs. EDF Energy understands Ofgem's rationale for wishing to include this but believe that this is an unnecessarily restrictive inclusion.

A recent example of a fundamental change in legislation that would not have been easily measurable by Ofgem would be the creation of Integral Features. This legislation recategorised some assets that would have been long life, some assets that would have been general pool and some assets that would have been IBA into a new special rate pool. This was enacted legislation that would clearly have fallen right in the heart of what the trigger is supposed to cover (subject to the fact that the quantum may not have breached the trigger as it currently stands). It would not have been easy for Ofgem to quantify this, but it is very hard to argue that it wasn't a major change in legislation. In these circumstances, where it is not immediately clear from re-running the model what the adjustment should be, it would seem appropriate that the DNOs and Ofgem should collectively agree what adjustment is required. If this is not possible, then there should be a mechanism by which the benefit or cost to the DNO from the adjustment potentially breaching the trigger should be deferred until the following price control period, giving time for the DNOs to prove to Ofgem how the change works in reality, by demonstrating the effect on submitted corporation tax computations.

16.9. The Trigger Point

The trigger point is currently expected to be set at 0.5% of base revenue. EDF Energy believes this is too high and will lead to very material levels of risk remaining with the DNOs even if the trigger mechanism includes the three areas highlighted by the DNOs

but which have currently been excluded by Ofgem, namely changes in case law, changes in HMRC interpretations and changes in accounting standards. Therefore again it is important that this increased risk compared with DPCR4 is factored into cost of capital.

It is pertinent to note that a 2% change in the tax rate (which we believe Ofgem would regard as material) would not be large enough to breach the trigger as currently set. For instance, based on the DPCR5 Initial Proposals model for EDF Energy Networks (EPN) plc, a 2% change in the corporation tax rate would alter the average annual cash tax charge by £1.40m. 0.5% of base revenue would amount to an average of £1.91m per annum. Therefore it is clear that the trigger is currently set at much too high a level.

EDF Energy believes that a 1% change in corporation tax rate ought to be caught by the trigger and hence the trigger ought to be set at something closer to 0.15% of base revenue. In fact a more appropriate measure of the trigger would actually be to set the trigger at a cash amount equivalent to the effect of a 1% change in corporation tax rate.

17. Excluded Services

17.1. Treatment of excluded services metering

We do not agree with your proposed approach to make adjustments to the RAV based on outturn costs compared with forecasts. This would effectively cap the level of metering activity at the forecast level as the adjustment proposed makes no allowance for additional volume of activity. Our metering work is contracted out and the indirect support costs within the DNO's are less than £0.1m per annum in total. All costs are therefore captured as exluded services and not within the DUoS funded activities.