Rachel Fletcher
Director, Distribution
Ofgem
9 Millbank
London
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13 February 2009

Dear Rachel

EDF Energy's response to the December 2009 DPCR5 Policy Paper

We are pleased to provide our response to Ofgem's paper.

Our response is divided into the two sections attached. The first provides a summary of our key points, while the second explores these and other issues in more detail. We hope that our comments will be helpful to you and your team.

I can confirm that this response may be placed on Ofgem's public website.

Yours sincerely

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SECTION 1: EDF ENERGY'S KEY POINTS

This commentary sets out the views of EDF Energy on the key issues arising from Ofgem's policy paper published on 5 December 2008 about the electricity distribution price control review.

Overview

1. Ofgem's paper raises many questions but answers relatively few, leaving much work to do between now and July, when Initial Proposals are scheduled for publication. We had hoped that the policy paper would set out a clear framework for the rest of the review period, but considerable uncertainty remains even on basic issues, such as how RAV additions will work. Ofgem should work closely with the DNOs in the first part of 2009 to resolve these issues, and we would urge Ofgem to establish a number of joint working groups for this purpose.

Regulatory risk

2. There is much in Ofgem's paper which would have the effect of substantially increasing regulatory risk. At several points Ofgem refers to an ex-post denial of funding or incentive rewards on the basis that expenditure has been inefficiently incurred or that the incentive reward was unearned. These statements are either new ones or are the ex-post interpretation of vague statements made by Ofgem at DPCR4. They suggest that any allowances provided in DPCR5 can at best be regarded as interim sums, to be adjusted by Ofgem at some later date and in a manner which cannot be predicted.

3. Increasing regulatory risk is not only a perverse reaction to concerns about DNOs under-investing, but is also unlikely to promote additional investment in facilitating the development of a low carbon economy. Ofgem needs to take a step back and think more carefully about what it is trying to achieve and whether the solutions being suggested form a balanced and coherent package capable of attracting the required investment.

Cost of capital

4. Neither Ofgem nor the DNOs can predict the length or depth of the current economic crisis. Given the high levels of volatility, the broad-based nature of the recession, and the significant new investments needed, it is critically important that Ofgem continues to monitor developments in the capital markets right up until its Final Proposals. The rates locked into the DNOs' current

portfolios of debt may offer some cash flow protection for the DNOs, but this does not insulate them from the effect of a higher cost of capital on their propensity to invest.

5. In the likely event that high levels of uncertainty remain, we would support some form of trigger or re-opener mechanism to ensure that Ofgem sets the cost of debt at a level that adequately reflects the costs that DNOs will be exposed to. In doing so, it will be important for Ofgem to ensure that DNOs are incentivised to efficiently manage the cost of their debt.

Financeability of the proposals

6. In assessing the financeability of its price control proposals, Ofgem must ensure that the assumptions it uses to estimate the cost of capital are fully consistent with those used in its financial models. This is particularly important for DPCR5 because one impact of the credit crunch has been to widen the spread between A3/A- rated companies and those with weaker credit ratings.

7. Furthermore, in assessing financeability in the past, Ofgem has been able to improve a DNO's position by assuming a proportion of index-linked debt. In DPCR5, however, Ofgem will need to make realistic assumptions about the availability of such debt. Currently, following the demise of monoline insurance as a form of credit endorsement, the market for index-linked debt has all but dried up. Evidence of an enduring recovery will be needed before Ofgem can make assumptions about the future use of such debt by the DNOs.

8. Ofgem should be very cautious in assuming the availability of new equity finance, whether through rights issues or through retained earnings. Moreover, significant changes to regulatory assumptions about depreciation should not be made without being certain that the value of existing equity is not being diluted.

Ofgem's measure of return on equity

9. Ofgem's focus on only part of the price control settlement (ignoring gearing, debt costs, tax, and restructuring costs) runs the risk of misleading stakeholders. It also seems to undermine the idea that price controls should be seen as a package to be assessed, and then accepted or rejected, in the round. The DNOs themselves cannot currently obtain a reference to the Competition Commission on a partial issue, so it is inappropriate for Ofgem to assess their performance using partial measures.

Target return on equity

10. In view of the above, and without firm proposals on what the DNOs will be asked to achieve, how much that would cost to deliver, and what the risks of under-performance will be (including, of course, assessment of what proportion of risks are outside the control of the DNOs), it is not possible to answer Ofgem's question about the range of return on equity that would best represent a fair balance between customers' and shareholders' interests.

Treatment of severe weather events

11. We can see no rationale for Ofgem to tighten the current severe weather mechanism as a result of increased investment. The mechanism is in effect self- correcting because, as companies invest more in improving their network resilience, fewer events will meet the current thresholds and hence fewer CIs and CMLs will be excluded from the Information and Incentive Scheme.

Future proofing

12. We agree that it is sensible for DNOs not to replace assets on a like-for-like basis where a degree of future-proofing can be built in at reasonable cost. We have been following such an approach for some time and believe that we are relatively well placed to facilitate change.

13. The final report on Ofgem's LENS project gives an insight into the kind of network scenarios that could emerge by 2025 and 2050. While the five scenarios presented provide for a very wide range of possible outcomes when viewed from a purely environmental and economic (rather than political) perspective, it is clear that the current direction of the government's renewable energy strategy will lead to a need both for high levels of transmission investment and for distribution networks to be more actively managed in future.

14. We therefore suggest that a far more considered and integrated approach to demand-side management (DSM) needs to be developed. Such an approach would consider the respective roles of suppliers, DNOs, TNOs (and the GBSO), potential new players such as aggregators and virtual power plant operators, and not least customers.

15. An important outcome would be the development of a regulatory and commercial framework that would enable all of those players to interact in an effective and co-ordinated manner such that the government's renewable energy strategy and carbon emission reduction targets can be delivered in time, and at reasonable cost, and such that customers are able to benefit financially from demand-side participation.

16. Moreover, if DNOs are to offer DSM services that can have any meaningful effect on those who are connected to our primary substations, then agreements would need to be in place with hundreds if not thousands of customers. In turn, this would require a significant workforce to market the DSM services and to negotiate agreements with customers, an infrastructure to monitor behaviour (including access to smart meters and any control functionality they may have), and, potentially, DNO control of communications-enabled appliances.

17. Nowhere in Ofgem's policy paper is this potential business line for the DNOs discussed fully and properly.

Policy on deferred investment

18. We understand the principle that DNOs should not benefit from inefficient deferment of investment. However, Ofgem will need to be careful in applying this principle because, if a crude approach is taken, then efficiency incentives will be undermined.

19. It would not be in customers' interests for DNOs to incur expenditure which, as a result of previously unforeseen circumstances, subsequently proved possible to defer. Equally, it would not be in customers' interests for DNOs not to bring forward investment the need for which had previously been unforeseen. Such flexibility is a necessary element of efficient network investment management, which the Information Quality Incentive is ideally suited to facilitate.

20. We are also concerned that Ofgem seems to be suggesting that deferment of investment during times of high commodity prices is not in customers' interests and should be funded by shareholders. Deferring investment to a later period when cost levels have reduced will benefit customers through lower charges in the long run. Customers, had they the means to express a choice, might well choose a small and short-term increase in risk as a fair trade-off.

21. DNOs are in a position to make this judgement on behalf of customers, whereas if commodity price risk is passed through to customers (as Ofgem is suggesting), then no choice can be made.

Load-related drivers / triggers

22. In implementing any new driver, Ofgem will need to consider interaction with the mechanism of the Information Quality Incentive. In the current economic environment, where the impacts of the credit crunch are unfolding daily, it would be unreasonable for a DNO to have reduced incentive

opportunities simply because Ofgem had taken a more pessimistic view of the economy (and hence of load growth) than the DNO, particularly when the price control is to be de-risked by the use of load-related drivers.

Attitude to risk / use of caps and collars on overall equity returns

23. We would support a limited use of caps and collars on individual incentive schemes where there is a high risk of unforeseen gains or losses – i.e. where an incentive is new and has no track record, or where the reported performance is significantly outside the DNO's control. Such limits should be set if possible by reference to ranges around mean values of customer willingness to pay.

24. On the question of overall caps and collars on equity returns, we shall need more information on the incentive package in terms of scope, calibration, and risk as well as on the proposed cost of capital before we can be in a position to make an informed comment.

Meters stranded by smart meters

25. We are pleased that Ofgem has recognised this as an issue. However, although it does affect some other market participants, it is predominantly a DPCR5 issue and will need to be settled within the Final Proposals.

Incentives and the IQI

26. Ofgem claims (for reasons which remain unclear) to have improved the Information Quality Incentive Scheme by not allowing DNOs to make changes to the initial forecasts they submit. However, since the incentive matrix has not been published, it is difficult to see how the DNOs are able to react to this if rebidding is not permitted – thus destroying the incentive.

27. Ofgem's decision also allows it to set IQI amounts below the level of any reasonable forecast, while insisting that the DNOs remain committed to their forecasts – another example of increased regulatory risk.

Output measures

28. Ofgem wants the DNOs to commit to a range of network output measures "in return for their use of system charges" and says that it "would like, as a matter of principle, wherever possible to agree ex-ante mechanisms to adjust allowed revenues according to performance against the outputs".

29. Some measures already expose DNOs to a revenue risk, for example CIs and CMLs. However, these are capped and collared (+/-3% in the case of the Interruptions Incentive Scheme). If new outputs are to be linked to revenue

recovery, the rules will need to be set out clearly in advance and the amount of revenue at risk must be clearly defined.

30. It also needs to be made clear what happens if a DNO exceeds an output target – will this be rewarded, and if so by how much? Creating an unspecified risk of subsequent denial of cost recovery would increase the cost of capital, as also would creating new output measures which have only downside potential (i.e. are an asymmetrical risk for the DNOs).

Equalised incentives for capex and opex

31. We support the development of equalised incentives for capex and opex. As Ofgem is aware, we continue to believe that there are significant differences in the way that companies report their costs under the RRP and that distortions are occurring as a result of the current differentials. We assume that since capex incentives are symmetrical (unlike the current opex incentive), any enlarged incentive would also be symmetrical. It is important to a proper understanding of the final price control proposals when they emerge later this year that Ofgem should confirm this point.

Carbon footprint reporting

32. We broadly support Ofgem's proposals for business carbon footprint reporting, and we endorse the use of well-established frameworks and tools, such as the GHG protocol and Defra conversion factors. We agree that, with the exception of losses, a DNO's carbon footprint is unlikely to be large enough to warrant the use of financial incentives.

Technological and commercial innovation

33. Ofgem appears to be aiming to create a sea-change in DNOs' behaviour while imposing no additional risks on consumers. We do not see how this will work, or indeed why it should be regarded as the right approach. For example, Ofgem says that DNOs will be rewarded or penalised according to "project outcomes": i.e. if a DNO undertakes an innovative project in good faith it may nevertheless be penalised for a poor outcome, despite the fact that Ofgem is likely to offer a cost of capital that is only appropriate for a low-risk business.

34. As Ofgem will be aware, EDF Energy has been particularly proactive in the field of technical innovation and has enthusiastically embraced the philosophy of the Innovation Funding Incentive. We would like to continue in that vein and we are particularly keen to ensure that Ofgem's embryonic ideas in respect of innovation and future networks are developed and that an effective and balanced (in terms of risk) incentive mechanism is established in

good time to permit technologically and commercially innovative products to be developed and tested during the DPCR5 period.

35. Ofgem needs to be aware that the development of innovative approaches by the DNOs suggests a renewal of intellectual resource which has been eroded by the focus on cost reduction throughout the past 18 years. Asserting the need for further reduction at a time when the DNOs should be gearing up for significant change would be counter-productive.

Incentives on exit charges

36. While we understand Ofgem's philosophical aversion to pass-though arrangements, we do not support the development of incentives in this area.

37. Ofgem accepts that DNOs have little influence over the capital costs of the relevant transmission assets, but does not explain why transmission companies would offer us "innovative deals": after all, they are a monopoly provider of such connections and have no reason to offer any arrangements which could increase their own costs. Furthermore, the idea that DNOs can cost effectively implement "non-network solutions" to limit volume increase or defer reinforcement is not supported by any history of successful initiatives or, indeed, any analysis to show that these could be practicable and cost effective.

38. The reality is that EDF Energy and National Grid have an established and very effective joint planning liaison procedure. Meetings take place at regular intervals where emerging requirements for transmission and distribution investment (for example, in respect of SQSS and P2/6 obligations, fault levels, and condition-based asset replacement) are carefully considered from a whole-cost perspective (taking account of both transmission and distribution options).

39. Each option presented is subject to a thorough challenge process by both parties, a process which can be made visible to Ofgem if required. It follows that there is no need for any artificial "incentive" to encourage companies to do what they already do.

Losses incentive

40. Ofgem's proposals for amending the current losses incentive pose an unacceptable financial risk for EDF Energy during the DPCR5 period. The risk arises because Ofgem proposes to significantly tighten the targets and increase the incentive rate at a time when reported losses are increasing. The estimated financial exposure to us is of the order of £200 million over the DPCR5 period.

41. We are concerned that Ofgem's current proposal will not meet the desired policy objective of incentivising DNOs to invest to reduce losses. A key

outcome of observing the operation of the current losses mechanism is that the data from the settlement system is volatile. We have particular concerns that the rollout of smart metering will exacerbate this volatility. Our view is that:

- Installation of low loss equipment should be incentivised through an appropriate input mechanism (at an incentive rate which incorporates the cost of carbon); and,
- A subsidiary incentive on non-technical losses which should continue via an output-based scheme, but with a reduced incentive rate (i.e. which excludes the cost of carbon) and caps and collars.

42. As we have stated above, we still see a role for an output-based incentive mechanism. However, we have significant concerns over the proposed changes to both the target-setting methodology and the incentive rate. The main problem is that Ofgem's proposals are based on a philosophical attachment to output measures which in this particular case is inappropriate.

43. Technical losses are driven by physics, and so the impact of engineering actions to reduce losses can be predicted with sufficient accuracy to avoid the need to rely on an outputs measure. A modelled approach which underpins capex allowances also creates a direct connection between engineering choices and incentive rewards – something which would greatly facilitate the relevant business case decisions.

44. A settlements-based approach also does not work where, because of the risks involved, it needs to have restrictive caps and collars. This is because DNOs will find themselves beyond these points relatively often and in a place where the marginal losses incentive rate (the one which will be used for each marginal investment decision) is zero. Indeed, with a marginal losses incentive of zero there would actually be a disincentive on DNOs to reduce losses arising from the capex/opex incentive. This does not seem sensible.

Installation of smart meters on low voltage substations

45. As Ofgem has recognised, networks need to be future-proofed to meet the growing carbon challenge. However, instead of installing smart metering at low voltage substations, we would propose that intelligent network devices should be installed, which would not only improve losses information but also provide a platform for developing active distribution networks. In our view, a practicable rollout period would be at least five years.

Customer satisfaction measure

46. While we support the idea of trying to establish measures of customer satisfaction, we have strong concerns about whether this is really a practicable proposition. As Ofgem is aware from its own willingness to pay work, customers have very little awareness of business separation and of the respective roles of suppliers and distributors (let alone of the various metering agents). Indeed, Ofgem found it necessary to specifically educate its focus groups so that the later stages of the WTP survey would have a chance to be meaningful.

47. We think that it is most unlikely that a customer survey could overcome this problem, with the inevitable result that the views of customers will continue to reflect the performance of a range of parties and not just that of the DNOs.

Connections regulation

48. We support the encouragement of more competition in connections. But we do not agree with Ofgem's diagnosis of current connections performance by the DNOs, and hence we cannot support Ofgem's proposals to introduce a substantially increased regulatory burden.

49. Although Ofgem's paper shows connections as the biggest category of referrals to energywatch (323 cases out of a total of 878, or 37%), Ofgem should not be surprised by this, as connections are the most routinely complex area of customer engagement for the DNOs. A total of 323 complaints over 30 months are only 11 per month, across Great Britain as a whole, compared to an average number of connections made per month in 2007/08 of 42,300. The complaint rate is therefore just 0.03%. So Ofgem's proposals to introduce more regulation into this area of activity do not pass the proportionality test.

50. Ofgem proposes price regulation for market segments where competition is unlikely to be effective, but has not explained why the protections that have been in place since 1990 – Ofgem determinations, escalation to consumer councils (later energywatch, and now an ombudsman service) – are no longer appropriate. We do not believe that Ofgem has made out a case for introducing SLC15 obligations to all connections, or indeed for introducing price regulation for market segments where competition is unlikely to develop.

Exposure to quality of supply incentives

51. In the past, the Interruptions Incentive Scheme has set a strong incentive to encourage the DNOs to apply automation and/or remote control technology to their networks as part of an overall quality of supply improvement strategy.

This has been very effective in cost-effectively reducing CIs and CMLs, and customers have undoubtedly benefited as a result.

52. However, there is a natural level of saturation for this technology beyond which any further incremental improvements in quality become increasingly less cost-effective: a classic diminishing-returns scenario. Similarly, cost-effective "opex" solutions, such as deploying dedicated rapid response teams, can be very effective in reducing restoration times (and hence CMLs) but, once they are fully established, further improvements in "physical" response times become increasingly less cost-effective.

53. Further incremental improvements in quality of supply indices are hence unlikely to be cost-effective or consistent with customer willingness to pay criteria. It is in this context that we believe that the DPCR5 CML targets for EPN and especially SPN are too stretching. The fact that we are making good progress towards DPCR4 CI targets for all three networks testifies to the cost-effectiveness of our automation and remote control technology. But further progress in CML reductions will require step improvements in network reliability (i.e. reducing fault rates), which is likely to be either unduly expensive or impractical.

54. Under the current mechanism, up to 3% of revenue is exposed to CI and CML performance. Our concern is that, as Ofgem progressively tightens the targets, so the potential impact of one large event grows. While this risk has been present in the current period, the combination of a future tightening of the targets with an increasing investment programme means that the likelihood of such an event is greater and its potential impact more significant.

55. As Ofgem has recognised, the impact of these events can be mitigated. Of the options presented, we would favour applying a weighting to 132kV and EHV incidents. This is administratively the least burdensome option, and also the simplest to apply. Our initial view is that a 50% weighting should be used. If this change is not implemented, the revenue at risk should be reduced to 2%.

Worst served customers

56. We agree that it is appropriate to define worst-served customers in relation to a maximum number of incidents that a customer should experience over a three-year period. Such an approach will ensure that the service experienced by the worst-served customers does not significantly diverge from that experienced by the "average" customer.

Opex benchmarking

57. We are pleased to see that Ofgem intends to take a robust approach to regional costs. We believe that in the interests of fairness Ofgem must make symmetrical adjustments so that both high and low cost area companies are normalised to the average cost level.

58. Ofgem should be circumspect in its use of cost benchmarking and its interpretation of the results. All that benchmarking can do is reveal differences in cost levels that are not explained by the drivers used. It cannot reveal any particular level of efficiency.

59. Ofgem's DPCR4 benchmarking (and its assertion of a 1.5% frontier shift) were clearly inappropriate (as we said at the time), given that most DNOs have exceeded their opex allowances. Ofgem's statement that comparative analysis will play a key part in the review (paragraph 4.24) is worrying and suggests that lessons have not been learnt.

60. There is a fundamental inconsistency in Ofgem wanting DNOs to be more innovative and flexible, while at the same time asserting cost reductions by drawing inappropriate and misconceived conclusions from benchmarking and further undermining the DNOs' pool of intellectual resource.

61. We are pleased to see a cost driver relating to investment activity – an omission which greatly undermined the DPCR4 analysis. The other drivers also are intuitively sensible, though they will themselves be insufficient to explain cost variations between the companies. For example, benchmarking fault costs against a single variable (fault numbers) cannot possibly capture the costs associated, beyond the basic overground/underground split, with the difficulty of finding, reaching, or accessing the location of faults.

62. We note that Ofgem understands the risks of using international benchmarking, particularly in respect of data credibility. However, issues also exist within this work, around differences in service levels, accounting practice, and investment cycles, making robust comparisons very difficult.

Pensions: timing of actuarial valuations

63. The best option for treating pension costs is to base the allowances on the DNOs' best estimates of the costs they will incur during the DPCR5 process. These estimates should be supported by the DNOs' professional pension advisers.

EDF Energy (Networks)

13 February 2009

SECTION 2: EDF ENERGY'S DETAILED RESPONSE

The layout of this section follows Ofgem's consultation document

Chapter 1: Introduction and overview

Regulatory risk

There is much in Ofgem's paper which has the effect of substantially increasing regulatory risk.

At several points Ofgem refers to the ex-post denial of funding or incentive rewards on the grounds that expenditure has been inefficiently incurred/the incentive reward is un-earned. For example in p1.19 the DNOs are threatened with denial of cost recovery if they do not introduce cost reflective charges. Similarly, in p4.1 Ofgem refers to any investment backlogs being funded by shareholders unless the DNOs can demonstrate clear efficiency benefits which benefit customers.

These statements are either new ones or are the ex-post interpretation of vague statements made at DPCR4. They suggest that any allowances provided in DPCR5 can at best be regarded as interim sums, to be adjusted by Ofgem at some later date and in a manner which cannot be predicted.

Indeed, Ofgem is adding to these risks by introducing new concepts such as "outputs" and "future networks" which look as though they will also only be interpreted ex post.

Indeed, at one point Ofgem is encouraging DNOs to think carefully about what sort of network will be needed for the low carbon economy (p2.48), whilst at the same time introducing ill-defined ex-post tests on efficiency. Clearly, as read, if DNOs make rational choices in the face of uncertainty based on current knowledge, they would be taking a risk that at some time later Ofgem will determine ex post that the investments were not efficient.

Increasing regulatory risk is not only a rather odd reaction to concerns about DNOs under-investing, but it is also unlikely to promote additional investment in facilitating the development of a low carbon economy. Ofgem needs to take a step back and think about what it is trying to achieve and whether the solutions being suggested form a balanced and coherent package.

Question 1: Do you agree with our assessment of how the DPCR4 settlement has performed in practice?

Ofgem's measure of regulatory return ignores three important aspects of company performance: actual gearing, tax and actual debt costs – all of which have been subject to incentives under the DPCR4 settlement. It is not therefore clear to us what advantage Ofgem's measure has compared to return on RAV. Using a partial measure is unlikely to be helpful to external stakeholders, particularly those familiar with more traditional measures of profit.

It is also wrong for Ofgem to have excluded restructuring costs since these have been incurred for the purposes of lowering costs and omitting them gives an over-inflated view of a DNO's profitability.

Each price control accepted by a DNO is done so on the basis that it is a package. The introduction by Ofgem of a partial measure seems to undermine this principle.

Question 2: Do you agree with the main lessons we have drawn from this assessment?

There is a risk under Ofgem's approach that individual elements of performance are assessed in isolation. For example, focussing on the losses incentive alone could suggest that DNOs have benefited from unearned profits (driven externally by the settlements system), when in fact they are largely compensating for losses caused by errors in other parts of the DPCR4 package.

Price control settlements inevitably contain compensating errors – particularly because Ofgem has, in the past, relied on simplistic techniques for assessing costs (for example, the Composite Scale Variable "CSV", reliance on a single year's data etc). Focussing on one element of the package and trying to relate that to actual service levels delivered is bound to be difficult.

Question 3: Have we identified appropriate measures to address our concerns and deliver a settlement that provides better rewards/penalties for highly performing/poorly performing companies?

Ofgem should assess the likely range of outcomes implied by the DPCR5 incentive and allowance package to check that the resulting risk is consistent with the cost of capital. Such checks should help reduce the risk of error and of inappropriate calibration of incentive schemes.

Question 4: Do you think our proposal to base DNOs' incentives for under/outperformance around their effective return on equity is appropriate?

No. As we discuss above, past price controls have been accepted as a package for which a partial measure is inappropriate. Only if and when each element of Ofgem's price control process is robust and can stand alone would partial or

even individual measures be informative. DPCR5 will, hopefully, move us towards this position, but given differences in DNO regulatory reporting, important errors are likely to remain.

Question 5: If you do, what range of return on equity do you think would represent a fair balance between customers' and shareholders' interests to reward increased efficiency, better service and innovation, whilst maintaining strong incentives for shareholders of any poorly performing DNOs to improve performance?

It is not possible therefore to answer Ofgem's question without firm proposals on what the DNOs will be asked to achieve, how much that would cost, and what the risks of underperformance will be (including of course an assessment of what proportion of risks are outside the control of the DNOs).

Customers may be willing to fund relatively large rewards in some cases (for example, environmental matters) but not in others. Similarly, one DNO may wish to see a relatively high reward/high risk package, whereas another may not. However, it is important that Ofgem gains an understanding of the overall risk portfolio a DNO is being asked to bear and checks that this is consistent with the cost of capital. Analysis of stock market data may reveal the range of returns for companies with betas equivalent to the DNOs.

Others issues not included in questions

Meters stranded by smart meters

We are pleased to see that Ofgem has now recognised the stranding issue (p1.16).

We understand that the issue of meters stranded by a mandated roll-out of smart meters impacts on GDN and unregulated metering provision agents as well as DNOs. However, if practicable, it is sensible to address the DNO issues as part of DPCR5.

Initial views on risk sharing

Ofgem's adoption of a risk framework in order to decide on the appropriate mitigations is a welcome one.

With regard to p1.46 "practicality" should be defined in terms of the need to identify an objective measure of variation in costs, and "desirability" would be the final overall judgement rather than a criterion itself.

Incentives and the IQI

For reasons which appear somewhat speculative (concerns about the DNO being able to influence Ofgem's benchmark), Ofgem says that it has improved the IQI by not allowing DNOs to make changes to the initial forecasts they submit. However, since the incentive matrix has not been published it is hard to see how the DNOs are able to react to them if rebidding is not permitted – thus destroying the incentive.

Ofgem's decision also allows it to set IQI amounts below the level of any reasonable forecast, whilst insisting that the DNOs remain committed to their forecasts – another example of increased regulatory risk.

Obligations on DNOs

Ofgem wants the DNOs to commit to a range of network output measures "in return for their use of system charges" and says that it "would like, as a matter of principle, wherever possible to agree ex-ante mechanisms to adjust allowed revenues according to performance against the outputs".

Some measures already expose DNOs to a revenue risk, for example CIs and CMLs. However, these are capped and collared (+/-3% in the case of the IIS). If new outputs are to be linked to revenue recovery the rules need to be set out clearly in advance and the amount of revenue at risk must be clearly defined.

It also needs to be made clear what happens if a DNO exceeds an output target – will this be rewarded, and if so by how much?

Creating an unspecified risk of denial of cost recovery would increase the cost of capital, as would creating new output measures which have only downside potential (i.e. are an asymmetric risk for the DNOs).

Chapter 2: Environment

Question 1: Do you agree with our view of future uncertainties and the need for DNOs to change their way of working and thinking to encompass innovation and flexibility?

We agree with Ofgem that the pace and scope of changes required to move to a low carbon economy are currently uncertain, and that it is essential that the DNOs are ready for the changes when they happen rather then being seen as impediments to it.

Ofgem paints a picture of DNOs having a traditional approach and being unwilling to change. However, the DNOs are products of successive regulatory packages designed to produce low cost and low risk distribution services. If Ofgem wants this to change then it must offer appropriate incentives.

DNOs will change in response to appropriate obligations, incentives and funding in respect of the DNO's future role, including any new and enhanced services to be provided (such as those outlined under Key Points above).

However, as Ofgem will be aware, EDF Energy has been particularly proactive in the field of technical innovation and has enthusiastically embraced the philosophy of the Innovation Funding Incentive. We are committed to continuing in that vein and are particularly keen to ensure that Ofgem's embryonic ideas in respect of innovation and future networks are developed and that an effective and balanced (in terms of risk) incentive mechanism is established in good time to permit technologically and commercially innovative products to be developed and tested during the DPCR5 period.

Ofgem needs to be aware that the development of innovative approaches by the DNOs suggests a renewal of intellectual resource which has been eroded by the focus on cost reduction over the past 18 years.

Question 2: What are your views on our proposals for DNOs to provide more information to help low carbon initiatives and have we adequately identified and defined the information requirements?

We believe that there is merit in DNOs being required to provide standardised web-based information tools for generators (and other users such as customers, GBSO etc). Such tools could provide assistance with generators' location decisions through providing:

- A regional view including zones indicating potential for low cost connection – this could include a standard menu of reports designed to assist with more granular locational choices

- Information of nodally specific use of system charges (i.e. nodal LRIC charges at EHV)
- Indicative connection charge estimates (e.g. the E-connect tool)

We are currently developing the E-connect tool (now with IMASS) using IFI funding. The idea is that developers would buy a licence to access the system. The main advantage for us is that it could reduce the volume of speculative enquiries by enabling developers to test options themselves and eliminate those that appear impractical or too costly. However, the commercialisation of this service by IMASS/E-connect will depend on the level of support from DNOs and developers.

In developing these tools we also need mindful of security issues, and it may be appropriate to grant access to information about our electricity infrastructure only a licences basis following appropriate screening.

Question 3: Do you agree with our proposal that all distributed generation should pay use of system charges, and if not, can you provide evidence to substantiate your specific concerns?

Yes.

It is helpful that Ofgem is prepared to allow DNOs to pay compensation to pre-2005 DG. However, it is not clear why the generators should accept the compensation unless it is substantially higher than the costs currently "avoided". Moreover, if DNOs are mandated to negotiate the change (e.g. through a licence condition), the relevant generators will be able to demand any price.

We note that the "deep" charging arrangements in place prior to 2005 only included the cost of new assets used to make the connection. The extent of the asset covered by a deep connection charge will have varied greatly between connectees depending on the local circumstances.

It will be very difficult (if not impracticable) to retrieve details of connection offers made many years in the past and hence to develop customer specific compensation arrangements.

Question 4: Do you agree that the distributed generation (DG) incentive should be retained? Should embedded transmission be deemed relevant DG?

We noted in our response to Ofgem's initial consultation document (June 2008) that in our experience, the current DG incentive is ineffective because the majority of costs required to connect generators in our areas are sole-use costs recovered through connection charges.

We do not see this situation changing in DPCR5. Nevertheless we recognise that this pattern may change overtime.

We agree that treating embedded transmission as relevant DG is sensible.

Question 5: What are your views on our proposals on innovation and flexibility? How would you rate their feasibility and which option is most likely to drive the more innovative and flexible behaviour that we are seeking?

Ofgem appears to be aiming to create a sea-change in DNOs' behaviour while imposing no additional risks on consumers. We do not see how this will work, or indeed why it should be regarded as the right approach.

Figure 2.4 explicitly says that DNOs will be rewarded or penalised according to "project outcomes": i.e. if a DNO undertakes an innovative project in good faith it may nevertheless be penalised for a poor outcome, despite the fact that Ofgem is likely to offer a cost of capital that is only appropriate for a low-risk business. Option 3 has no incentive properties unless the rewards are defined in advance.

Ofgem's proposals for DNO new roles/services are set out in the table below, together with the proposed funding arrangements. In some cases the funding arrangements are unclear:

Future proof network investment (2.14)	Funding an enhanced specification for equipment used on a routine basis (such as switchgear) would be best included in capex unit costs and funded ex ante (option 1).
Innovative approaches to connecting DG (2.17)	Defined programmes or projects to trial innovative connection solutions may fall under a new innovation mechanism (p2.65) option 2
Adopt new commercial arrangements e.g. for DG (2.20)	The types of new commercial arrangements are not clear but presumably include procuring DG support in lieu of reinforcement. Funding of payments to generators from capex allowances is implied. Allowances for DG support prospecting/commercial workforce and for commercial management/monitoring of DG agreements not specified.

Provide information, advice and guidance to DG (2.24)	Material costs are likely to be incurred in the development and provision of web-based information tools (e.g. heat maps/connection calculator. Funding is unclear – access by subscription is feasible, in which case excluded service status would need to be clarified.
Make connection easier (2.24) – proportionate administrative requirements, and code developments	Probably low cost – limited funding issues
Proactively promote DSM (2.31)	Equalisation of capex and opex incentives (2.55) – implies funding of DSM payments to connectees from capex allowances Allowances for DSM prospecting/commercial workforce and for commercial management/monitoring of DSM agreements not specified.
Carry out R&D (2.60)	IFI retained with no change to scope.

Our preferred matrix of funding and incentive arrangements is set out in the table below:

Category	Preferred funding approach	Reason	Incentive
Enhanced functionality for "business as usual assets"	Ex-ante capex allowances	Cost integral to main item	Disincentive through capex incentive needs to be reversed into a positive incentive to invest

Research and development	IFI scheme	R&D has uncertain benefits – "use it or lose it" funding suitable for discretionary nature	80% pass-through assumes remaining 20% funded through innovation implementation – however the IFI does not cover implementation so benefits realisation difficult. IFI should be extended to include trialling to increase prospects for benefit realisation.
Deployment (following trialling)	Project specific – upon application	Benefits and costs likely to be bespoke to each initiative	Risk, and hence reward, likely to be bespoke to each initiative (i.e. Ofgem option 2)
Information services, including web access	Opex allowances	Basic service without known uptake levels	None – but will need clear obligation to deliver service to counteract opex incentive
DG support/demand-side management prospecting	Opex allowances	Basic service without known uptake levels	None – but will need clear obligation to deliver service to counteract opex incentive

DG support/demand-side management payments	Capex allowances/RAV	Payments are in lieu of load-related capex and need to be recovered through the RAV.	Efficient solution would lead to capex incentive reward – but unclear if capex incentive sufficient to fund added risk of DG/DSM solution (e.g. conflict with IIS) – especially if incentive rate is reduced by IQI. Needs further consideration.
Other changes (e.g. to statements, guidance for generators etc)	None – assumed cost not material	n/a	Would accept suitable licence obligation if required (may be needed to counter impact of opex incentives)

The table shows that there are areas where Ofgem is asking DNOs to carry out new services, principally to procure DG/DSM support, but has not yet given consideration to their funding (e.g. costs of a prospecting workforce).

It is noted that opex solutions to connecting DG will be facilitated by equalising capex and opex incentives rates, but there is no mention of how the opex is to be funded in the first place.

Ofgem is also silent on the issue of risk and, in particular, what risks a DNO should take in relying on DG/DSM rather than conventional reinforcement. An ex-post judgement (e.g. following a large incident) is hardly likely to encourage DNOs to go down the DG/DSM route.

Question 6: What are your views on our proposal to set an incentive on transmission grid exit charges?

While we understand Ofgem's philosophical aversion to pass-though arrangements, we do not support the development of incentives in this area.

An incentive based on a simple percentage would not align well with the "lumpiness" of costs associated with new exit charge schemes. For example,

an increase in capacity of one 240MVA super grid transformer (the smallest increase it is usually possible to obtain from National Grid) onto a 'greenfield' GSP site away from major urban centres typically costs £6-8m. This equates to around £750k in exit charges per annum. This is a significant amount in relation to the expected commitments laid out in our FBPQs. Unless a scheme was created with wide tolerance bands a DNO could face a significant and uncontrollable risk.

Ofgem accepts that DNOs have little influence over the capital costs of the relevant transmission assets, but does not explain why transmission companies would offer us "innovative deals"; after all, they are a monopoly provider of such connections and have no reason to offer any arrangements which could increase their own costs.

Furthermore, the idea that DNOs can cost-effectively implement "non-network solutions" to limit volume increase/defer reinforcement is just speculation and is not backed up with any evidence of successful initiatives or any analysis which suggests that they could be practicable and cost effective.

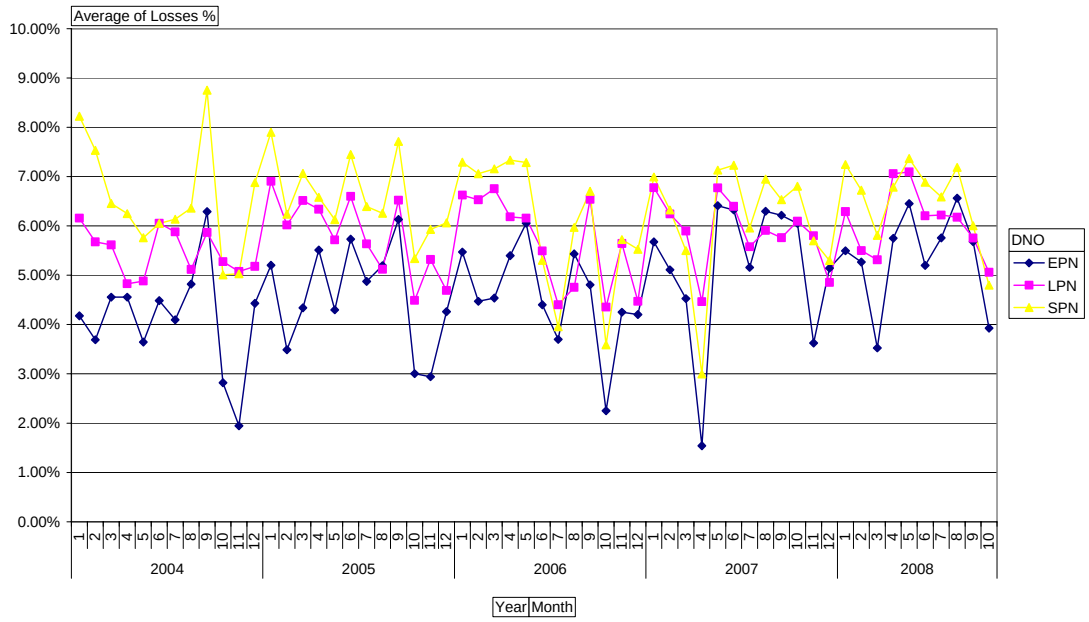
The reality is that EDF Energy and NGET have an established and very effective joint planning liaison procedure. Meetings take place at regular intervals where emerging requirements for transmission and distribution investment (for example in respect of SQSS and P2/6 obligations, fault levels, condition-based asset replacement etc.) are carefully considered. Investment scenarios are considered from a "whole cost" perspective (i.e. taking into account both transmission and distribution options). Each option presented is subject to a thorough challenge process by both parties and Ofgem should rest assured that the process results in solutions which represent the best interests of customers. It follows that there is no need for any artificial "incentive" to encourage companies to do what they already do.

Consistent with the principles of better regulation, Ofgem should propose a change from the current pass-through arrangements only where it is able to demonstrate the existence of transmission connection assets which have been built since vesting (when the pass-though arrangements were first put in place) but which are now stranded. We are not aware that any such evidence exists.

Question 7: What are your views on our losses proposals, and do you have any additional comments on the option to install smart meters on low voltage substations?

Ofgem proposes that the current settlement-based losses incentive scheme is continued. EDF Energy is concerned that this approach will place substantial risk on DNOs, without necessarily impacting the actual level of technical losses.

As illustrated in the following graph, a review of the losses percentages for EDF Energy's DNOs, based on settlement data, shows substantial variation in the observed losses.



The first point to notice from the settlements-based data above is that technical losses in the range of 1.5% to 3% are physically impossible! In addition, detailed regression analysis of this data indicates the following:

- Even allowing for seasonal effects – where losses percentages follow a pattern that tends to repeat on an annual basis – at best we can only explain ~50% of the variability in the data.
- After adjusting for seasonal effects in this data, changes in technical losses explain at best less than 20% of the remaining variation in the data.
- We believe the repeating annual pattern is driven by errors in estimating the half-hour by half-hour consumption of end customers (based on settlement profiles) rather than changes in technical losses.
- There is an underlying trend of increases in losses over time which is not explained by an increase in consumption (and hence an increase in technical losses).

This leads us to the following conclusions:

- Ofgem's proposed losses incentive will do little or nothing to incentivise the reduction in technical losses.
- Because the level of losses, as observed from settlements data, is subject to such variability, the proposed losses incentive will increase the financial risk observed by UK DNOs.
- We believe that most of this variability (and hence financial risk) arises from "profile drift", where the actual half-hour by half-hour pattern of consumption for customers who are not half-hourly metered (mainly domestic customers) differs from that assumed by settlements. Profile drift is likely to worsen as customers install micro-generation and/or take part in DSM schemes because generic settlement profiles will become increasing less relevant to their modified patterns of consumption.
- Half-hour by half-hour consumption patterns are likely to change substantially over the DPCR5 period, both as a result of energy efficiency initiatives and of the credit crunch – increasing the extent of profile drift, and hence uncertainty in the level of losses.
- The roll-out of Smart Metering and the impact on settlements is hard to predict and could create significant data disturbance.
- The current and increasing level of financial risk imposed on DNOs by a losses scheme of the form suggested by Ofgem increases DNOs' cost of capital, and hence the cost to customers.
- This increase in costs is likely to exceed any benefit from reduced technical losses.

Form of losses incentive

Ofgem's proposals for amending the current losses incentive pose an unacceptable financial risk for EDF Energy in DPCR5. This arises because Ofgem is proposing to significantly tighten the targets and increase the incentive rate at a time when reported losses are increasing. The estimated financial exposure to us in DPCR5 could be as high as £200m over the DPCR5 period.

We believe that an alternative and more sensible approach is available to Ofgem:

- Installation of low loss equipment should be incentivised via an appropriate input mechanism; and
- Non-technical losses should continue to be incentivised via an output-based scheme but with a reduced incentive rate and caps and collars.

As we have stated above, we still see a role for an output-based incentive mechanism. However, in any case, we have significant concerns about the proposed changes to both the target setting methodology and the incentive rate. These are discussed below.

Ofgem's proposals may be based on a philosophical attachment to output measures which, in this particular case, is inappropriate. Technical losses are driven by physics, and so the impact of engineering actions to reduce losses can be predicted with sufficient accuracy to avoid a reliance on an outputs measure. A modelled approach which underpins capex allowances also creates a direct connection between engineering choices and incentive rewards – something which would greatly facilitate the relevant business case decisions.

A settlements-based approach also does not work where, because of the risks involved, it needs to have restrictive caps and collars, since DNOs will find themselves beyond these points relatively frequently and where the marginal losses incentive rate (the one which will be used for each marginal investment decision) is zero. Indeed, with a marginal losses incentive of zero there would actually be a disincentive on DNOs to reduce losses arising from the capex/opex incentive. This does not seem sensible.

Detailed comments on Ofgem's proposals

We discuss the main elements of Ofgem's proposals below:

1. Ofgem must set targets that reflect the likely level of losses in DPCR5. The use of a short time period is not appropriate as it will not reflect the likely path of reported losses (as derived from settlements data) and will also not allow for the effects of the recent economic downturn on future losses.
2. It is unfair for Ofgem to set targets based on a 10 year period when reported losses are generally falling, but to shorten the period to five years when they are expected to rise. This puts an asymmetric risk on the DNOs and may even indicate that Ofgem is trying to achieve an element of claw-back – i.e. to effectively re-open DPCR4. If Ofgem has such a policy, then of course it would need to re-open other areas of the DPCR4 settlement in order to produce a fair result – for example, allowances for controllable costs. Ofgem should retain a 10 year period for target setting.

- The DPCR4 losses data is distorted by units in respect of consumption which actually occurred in the DPCR3 period. This problem is accentuated for a company like EDF Energy which has taken a very proactive approach to reducing non-technical losses, since the correction of many metering errors captures under-recording of consumption which has occurred over different periods.

3. Ofgem must either agree to our current data management costs or set a target with sufficient headroom to fund these costs. Not doing so would lead to inequalities, as it would give all of the benefit to customers while placing all of the risk on the DNOs.
4. Investment in low loss equipment (the DNOs' principal tool for reducing technical losses) should be funded through capex allowances and the losses targets adjusted to reflect this investment. However, it must be appreciated that over a five-year investment cycle, the scope for cost-effectively reducing technical losses is very limited, as our FBPQ table NL11 illustrates. It follows that the incentive mechanism would principally measure movements in non-technical losses and settlement system volatility. On this basis, it would be inappropriate for the incentive rate to be linked to energy prices and to the notional cost of carbon.
5. The unacceptable risk of a settlements-based approach must be mitigated – for example, by using caps and collars. The scope of revenue at risk must be considered in conjunction with the value at risk from the rest of the incentive package. Large potential swings in revenue will not be viewed favourably by the investment community (or indeed by energy suppliers), with a consequential impact on the cost of finance.

Choice of target

The current losses target is based on average performance over the period 1993/94 to 2003/04. Ofgem's current proposal is to base the losses target on a period of five years or less. The following table details the range of targets for EDF Energy's DNOs based on using a 10, five and three year time period.

	East of England	London	South East
Current target	6.3%	6.5%	6.5%
3 year average	4.4%	5.6%	5.8%
5 year average	4.5%	5.7%	5.8%

10 year average	5.2%	6.1%	6.1%

The key question that Ofgem must answer is which time period gives the best view of the level of future losses? 4.5% losses, as for EPN's five-year average, are simply not credible even from a purely "technical" losses perspective. Indeed, a move from 6.3% (the current target) to 5.2% (the target based on a ten year period) is an equally unrealistic movement in technical losses given the limited and slow moving range of lever we have. It follows that the expectation must be for the settlements system to return figures closer to longer-run historic levels in the future.

Losses reported in the DPCR4 period contain consumption which occurred in the previous DPCR period. Adjusting for this effect gives the following actuals/forecast:

DNO	2005/06	2006/07	2007/08	2008/09	2009/10	Average
EPN	4.2%	5.1%	5.7%	5.3%	5.6%	5.1%
LPN	5.5%	5.5%	6.1%	6.3%	6.6%	5.9%
SPN	6.2%	5.7%	6.6%	6.0%	6.3%	6.1%

The table demonstrates that the underlying average level of losses in DPCR4 is approximately 5% in EPN and around 6% in LPN and SPN.

The use of a short timescale also raises the issue of stranding the costs that have been incurred to deliver reductions in losses. Ofgem has recognised that EDF Energy has significantly invested in both systems and people to improve non-technical losses. These costs have been funded through the incentive payments in DPCR4. We know that other companies do not currently incur these costs and as such we are unlikely to have them allowed in any opex benchmarking process. However, if Ofgem sets the targets to capture all of this benefit immediately, then the company is faced with either:

- removing that workforce but remaining exposed to an increase in losses and hence incentive penalties; or
- continuing with the expenditure, even though it is unfunded, to maintain the current performance levels and minimise any future penalty.

Neither of these options is equitable, as customers receive all of the benefit but bear none of the future costs of maintaining that level of performance.

Choice of incentive rate

A key issue is that Ofgem proposes to double the current incentive rate to around £96/MWh. This, coupled with the tightening of the targets, would create an unacceptable financial risk for EDF Energy.

We believe that such an incentive rate would be too high and needs to be revised:

- The wholesale price of energy has fallen in response to economic crisis (much of this reduction reflects similar falls in crude oil prices).
- The incentive rate incorporates an element for carbon based on the Defra shadow price – which has declined significantly over the past six months. An EU permit to emit one tonne of CO_2 cost €10.15 (£8.86) at the end of January 2009 – down from €28.50 in mid-2008.

Actual movements in reported losses are due to a number of reasons, including the installation of low loss equipment, theft detection, data correction and settlements year on year volatility.

The biggest year-on-year variation will come from the ongoing settlements system volatility, which will have no impact on carbon. It is not therefore appropriate to use an incentive rate which will cause large annual swings in revenue as a result of settlement system volatility – volatility which, without constraint, would materially increase our cost of capital.

The largest reduction in carbon comes from the installation of low loss equipment. However, the most sensible way for Ofgem to incentivise this investment is to make an appropriate capex allowance reinforced by a suitable measure of low loss assets delivered. Once losses targets had been adjusted by the calculated improvement in losses from the installation of low loss equipment, the losses incentive (i.e. that based on settlements data) would only be measuring any movement in non-technical losses and settlement system volatility. Both of these have a significantly smaller impact on carbon and hence it would be not be appropriate for the incentive rate to include the full value of carbon.

Mitigating risk

Ofgem has proposed, at a high level, that the scheme should be capped and collared. This would be a positive development as it would mitigate the future financial risk.

The scale of the revenue at risk to the losses incentive cannot be considered in isolation from the revenue at risk from the rest of the incentive package. The

key issue is that the potential for large swings in revenue will not be viewed favourably by the investment community. Therefore, Ofgem must have due regard for overall downside risk when it is evaluating the price control package, to ensure that companies do not face increased financing costs. Currently, up to 4% of revenue is at risk in relation to network performance and the introduction of output measures may result in further revenue being at risk. This would tend to suggest that placing a modest value at risk of 1%-2% of allowed revenue at risk to the losses incentive would be appropriate.

An additional factor is that the roll-out of smart metering is likely to result in significant disturbance in settlements data, the scale and direction of which cannot be predicted. Given that the roll-out is anticipated to begin in DPCR5, this again would indicate that only a relatively modest amount of revenue should be put at risk.

Installation of smart meters on low voltage substations

It is our view that installing smart metering at low voltage substations would be a missed opportunity. As Ofgem has recognised, networks need to be "future proofed" to meet the growing carbon challenge. Therefore, instead of installing smart metering we would propose that intelligent network devices are installed which would not only improve losses information but would also provide a platform from which to develop active distribution networks, In our view, a practicable roll-out period would be at least five years.

Question 8: What are your views on the various aspects of the business carbon footprint proposals?

We broadly support Ofgem's proposals for Business Carbon Footprint reporting, and we endorse the use of well-established frameworks and tools, such as the GHG protocol and Defra conversion factors.

We agree that, with the exception of losses, a DNO's carbon footprint is unlikely to be large enough to warrant the use of financial incentives.

In respect of the detail of the proposed methodology, we support the organisational and operational boundaries described. However, we envisage that there will need to be some negotiation with contractors, either to obtain access to their existing records or to require them to commence/modify the collection of data. As a result of this, it is unlikely that we will be able to meet all of Ofgem's proposed data requirements until 2010/11.

In order that this scheme does not create an unreasonable administrative burden for the DNOs, there will need to be discussion with the industry over the granularity of data collected. For example, EDF Energy currently collects

information on energy usage for its major sites only and not for smaller operational facilities. Putting this in place could be a significant exercise. Note: we assume energy usage in substations will be excluded from this reporting.

In respect of the league table, we believe that the approach described whereby relative achievement in reducing the carbon footprint against an individual DNO baseline is the only practicable approach. The alternative would be to attempt to normalise the emissions to reflect the different scales and mix of activities of each DNO. We suspect that it would be impracticable to arrive at a satisfactory method for doing this.

We welcome Ofgem's proposal that past actions to reduce emissions will be taken into account when setting the baseline, and believe that this is essential if the league table is to be meaningful.

Question 9: What are your views on our proposals for refining the undergrounding scheme? In particular, should we apply caps per km of cable by voltage level or should we remove all voltage caps and just have a single overall cap?

We are pleased that Ofgem supports the continuation of the AONB scheme. We have found our work to be popular with stakeholders, a view which is endorsed by Ofgem's willingness to pay research.

Our views on the detailed areas discussed in Appendix 6 of Ofgem's paper are set out below.

Extension to include noise pollution

We agree that this is not appropriate.

Making participation on the scheme mandatory

We agree that it is not appropriate to mandate the participation of DNOs. Ofgem is aware that EDF Energy responded quickly to the creation of the allowance, using its existing established relationships with the EPN Protected Area bodies to create Steering Groups for EPN and SPN.

In our view, the DNOs may find it difficult to resist the demand from their stakeholders to respond to the publicly-stated availability of the allowance, since there is considerable publicity and lobbying within the Protected Area community as a whole.

We have invested in our stakeholder relationship to the extent that they expect us to be fully engaged in responding to their requirements. Far from being

mandatory at Ofgem's instruction, we consider that our CSR profile would suffer if we were to try to reduce the level of our participation in the scheme.

Proposed revised caps and principle of matching funding

Revised caps:

In October we provided details of costs to show how the threshold caps can be strongly affected by normal network design parameters. Our analysis showed that, over the whole programme, we have installed approximately 1200m of cable for each 1000m of overhead line removed. On average, we have also installed one ground-mounted substation for each 1000m of overhead line removed. We do not consider that these factors are accounted for adequately in the proposed caps.

Removing the voltage caps altogether would provide more freedom for the Steering Groups to select projects. The Steering Groups assess cost per km as part of their peer review and selection process.

Matching funding:

We agree that there may be opportunities to leverage the allowance by obtaining matching funding, but we regard this as a role for the stakeholders, not the DNOs. We consider that Ofgem's suggestion that DNOs should perhaps seek alternative funds, as well as possibly contributing to project costs, may raise inappropriate expectations among stakeholders.

In essence, we have taken the requirement to consult and communicate to the extent where the stakeholders select the projects for delivery by EDF Energy. The projects are therefore chosen in accordance with stakeholders' criteria, with technical advice for us. While some incidental network or customer benefit may be derived from the projects, we have not found any proposed projects which are likely to yield benefits on a scale which would justify our own investment; they are almost entirely for visual amenity improvement.

We discussed the potential for matching funding with the Steering Groups at the outset, suggesting that they may wish to consider leveraging as a criterion for selection. It is only recently, now that their process has reached a level of maturity (and as the unassigned DPCR4 allowance reduces), that the Steering Groups understand that they should consider how to add external funding (whether cash or in kind) to the allowance. In our consultation model, the Steering Groups are in no doubt that it is their responsibility to seek leveraging opportunities.

Extension to protected/conservation areas

We agree that the scope of the scheme should not be extended to other area designations. In part, it is difficult to see how appropriate customer representation could be organised without imposing a significant overhead for an extended range of stakeholders.

Avoiding new overhead lines in designated areas

We agree that it would not be appropriate to use the allowance to fund new underground connections.

Boundary issues where existing lines overlap visual boundary of designated area

We have experienced two aspects of this issue in the undergrounding projects we have undertaken in this period. Firstly, there are projects in respect of which the reasonably practicable solution to achieve undergrounding within the Protected Area requires the removal of the overhead line to a point outside the boundary. In the case of one particular project, the overhead line connecting one part of the Protected Area to another actually crossed undesignated land. In these cases, we proceeded with the projects in good faith to make progress and we have been advised subsequently that these elements of the project cost must be borne by our "normal" capex budget.

We consider that such elements of the project should be allowed in the DPCR5 allowance, provided they are a reasonable proportion of the whole underground proposition.

It should be noted that some of the Protected Areas in our footprints are coastal "ribbons", where there may be more potential for this type of issue.

The other aspect concerns the stakeholders' occasional requests for improvement of the view as seen from within the Protected Area, which affects overhead lines which are outside the area. In our experience, these requests have been made on the basis of a thorough assessment of the benefit to the landscape and visitor experience and they are rigorously peer reviewed by the Steering Groups.

We would ask that Ofgem reconsiders this issue. The scheme should support the improvement of visual amenity in Protected Areas irrespective of whether an element of the works lies outside the designated area. The involvement of the Protected Areas in peer reviewing scheme selection will ensure that robust judgements are made.

Interactions with normal replacement work

We agree that the allowance should be available to fund the relevant cost differential. To refer back to the discussion on matching funding, we see that this is the one example where the DNO may make a contribution.

DPCR4/5 overlap

We continue to work on the understanding that the DPCR4 allowance is "use or lose" by 31 March 2010, with the achievement criterion being the removal of the overhead line. However, the Steering Groups are concerned that they could find themselves in a position in March 2010 where the new underground network is energised and serving customers, but the decommissioned overhead line still exists because access has been denied. It is not unusual for the final removal of a decommissioned overhead line (which constitutes a very small part of the cost of an undergrounding scheme) to be delayed for many reasons outside a DNO's control, including the denial of access to land to avoid crop or land damage, disturbance of nesting birds etc. In such a scenario, nearly all of the project budget would have been spent in DPCR4 but the settlement may have to come from the DPCR5 allowance. Obviously, the Protected Areas and the landowners would be motivated to remove the dead overhead line at the earliest practicable opportunity, and we would ask Ofgem to consider ways in which criteria for "effective completion" could be agreed. We would suggest that "effective completion" should require evidence that the customers are connected to the underground network and that there is written evidence to demonstrate that the programme for removing the overhead line has been discussed in detail within a reasonable timescale.

We feel that this would be a significant gesture to show support for the continuing success of the allowance; failure to show a degree of flexibility would demotivate the stakeholders at a critical stage of development of the initiative.

Project officer funding

We are disappointed by Ofgem's decision but recognise the practical difficulties of funding a project officer within the context of a non-mandatory scheme. EDF Energy realised that the secondment of an experienced Project Officer to the Steering Groups was essential for enabling the Protected Areas to climb a very steep learning curve in terms of how to set about selecting candidate schemes and how to participate as stakeholders. It was also necessary to help transform their attitude to the potential for undergrounding from the traditional view of "it probably can't be done" to the new view of "Ofgem has provided an allowance

to improve our areas, and we are effectively in charge of directing where it is used". This took considerable time and effort to achieve, but Ofgem has met with members of the Steering Groups and we are confident that Ofgem has seen that they are fully informed and aware of the opportunities offered by the allowance and that they are strongly motivated to extract the maximum benefit in the future.

Question 10: Do you agree with our proposed approach for the treatment of fluid filled cables?

Ofgem does not appear to have understood the point that a replacement programme is not about the current risk of leakage, but rather future, far higher, rates of failure following further (and hard to predict) lead sheath degradation. The driver for replacement is the concern that in the future the condition of our FFCs may deteriorate at a rate faster than we can replace them, and that this could lead to quality of supply/resilience as well as environmental issues. We have previously discussed with Ofgem joint industry work, post the DPCR5 settlement, in order to further analyse the potential impact on future FFC replacement programmes. Explicit recognition of this intention as part of the final DPCR5 settlement would help to build some certainty in ensuring that this issue is tackled.

We support the proposal that all DNOs subscribe to the operating code and report to Ofgem/EA in a common format.

We are disappointed that Ofgem has not referred to our ground-breaking (and IFI funded) use of perflurocarbon tracing.

Chapter 3: Customers

Question 1: Do you think that the range of existing and proposed arrangements will deliver the levels of service customers expect?

Yes, we agree that the broad range of measures proposed should deliver the range of outputs that customers expect.

Question 2: What percentage of revenue/return on equity should be exposed to customer service and how should it be split between the various areas?

We do not believe that the quantum of the risk reward value should be measured against a notional return on equity. We believe that the value should be set as a percentage of revenue. Using a fixed return on equity would mean that different amounts of revenue would be at risk across the DNOs. As a consequence, potential revenue volatility would obviously be different across DNOs and hence the risk profile would also be different. Such an approach would not be compatible with a common cost of capital.

It terms of the split of revenue across the various customer satisfaction categories, we continue to believe that CIs and CMLs should continue to attract the largest share of revenue. However, the absolute level will be related to the structure of the IIS and, in particular, the exceptional events mechanism. Our views on this area are discussed in more detail in our answer to question 5. We can see no rationale for changing the current percentage of revenue at risk on the telephony standard (and, in the future, on the broad customer satisfaction measure) or altering the cap of 2% on the downside risk associated with the severe weather mechanism.

Question 3: Do you agree with our intention to develop a broad measure of customer satisfaction and the proposed advocacy approach?

Ofgem asks a number of specific questions:

Whether we agree with the overall approach for measuring and incentivising customer satisfaction

While we support the idea of trying to establish levels of customer satisfaction, we have strong concerns about whether it is a practicable proposition. As Ofgem is aware from its own willingness to pay work, customers have very little awareness of business separation and of the respective roles of suppliers and distributors (let alone the various metering agents). Indeed, Ofgem found it necessary to educate its focus groups so that the later stages of the WTP survey stood a chance of being meaningful. We think it most unlikely that a customer

survey will overcome this problem and that therefore the views of customers will reflect the performance of a range of parties, not just the DNO.

The one area where a survey may be possible is in the area of connections. This is because it is rare for there to be any supplier involvement.

We also have strong concerns about regional bias. In Ofgem's existing telephone survey LPN has been consistently scored below our other DNOs, despite our call centre using the same people and, to a large extent, the same information systems – the clear inference being that LPN's customers are harder to satisfy than others. Ofgem itself notes (p3.42) that customers in London have a higher willingness to pay (regarding interruptions) than in other regions, demonstrating that London customers do indeed have different needs. We would only support a survey that addressed this issue and allowed for the normalisation of results.

It is because of these concerns (and the steps that are necessary to mitigate them) that we would wish to take a lead role in the development and implementation of any new survey.

Ofgem should not attach rewards or penalties to any new customer satisfaction measure until a historic time series is available, because of the risk of errors/"noise" in the data. Any incentive would also need to be scaled against the cost of delivering improvements – which would be difficult given the broad range of matters to be included in the measure. We recommend that Ofgem uses the new measure as a monitoring or early warning tool (as ORR does in its annual report on Network Rail's performance).

Relevant considerations in developing an advocacy metric for DNOs

We support Ofgem's intentions to take advice from market research professionals on how to introduce the principle of advocacy measures in a monopoly business such as a DNO. However, at this stage we are doubtful that an advocacy metric would produce any meaningful results. We would be interested in seeing the lead-up questions proposed for the advocacy metric in order to be able to fully consider the likely effectiveness of this approach. For our Connections activity, we currently undertake independent customer satisfaction surveys with an external provider. We would be happy to test the advocacy approach by including relevant questions in the questionnaire used by our provider.

Whether the scope of the lead-up questions proposed are appropriate

We are unable to comment on the scope of the advocacy metric lead-up questions as we have not had sight of these.

We are satisfied that the attributes of customer satisfaction listed in Table 3.1 (p54 Policy Paper) are appropriate. We are also satisfied that the scope of the customer interactions is appropriate; however, Ofgem should consider combining Service Alterations and Supply Upgrades (Service Alterations and Upgrades), as these are essentially very similar activities.

Whether the scope of the customer interactions is appropriate

We are unsure what the "obtaining compensation" category refers to. Obtaining a Guaranteed Service Standard payment could be included; however, any compensation arrangements offered by a DNO are entirely voluntary and should not be included. "Service alterations" should exclude unmetered supplies as these are addressed in the relevant unmetered Service Level Agreements. New connections and supply upgrades are effectively the same thing and should be combined.

Who should conduct the surveys?

Because of our concerns about customer misunderstanding and regional bias (described above), we would prefer to conduct the surveys ourselves, so as to be better placed to understand the magnitude of this effect.

Telephony scheme

In principle, we are in favour of Ofgem running the telephony scheme in parallel with the new broad customer satisfaction measure for the early part of DPCR5 with a view, if practicable, to eventually replacing the telephony incentive with a broader customer satisfaction incentive mechanism. We are also in favour of streamlining the scheme to three attributes.

Inclusion of Unsuccessful Calls (App7 1.4 – 1.7)

We support the inclusion of unsuccessful calls within the incentive scheme, to supplement the telephony survey results. However, Ofgem should provide a clear definition of 'Unsuccessful Call' and ensure that the reporting criteria are applied consistently across all DNOs. We acknowledge Ofgem's acceptance that there may be reasons beyond a DNO's control for calls being unsuccessful and support the placing of the 75% weighting to account for this.

Incorporation of calls dealt with by messaging (App7 1.8)

In principle, we support Ofgem's proposal to incorporate an incentive on calls dealt with by messaging into the existing scheme. However, this will be dependent on the resolution of the associated data protection issues. We intend to investigate whether the DNO undertaking the survey, rather than Ofgem, will address this issue.

DNOs to run their own telephony system surveys (App7 1.9)

We support the proposal for DNOs to run their own telephony system survey.

Unlimited Exposure EGS2 (App7 1.25)

We support proposals to consider a cap to limit the financial risk from the unlimited exposure which exists from EGS2 compensation payments.

Complaint Handling (App7 1.26)

We fully support Ofgem's proposal to allow DNOs the opportunity of demonstrating that they have effective complaint handling procedures that meet the recommendations set out in the new CEAR complaint handling standard. We appreciate that we are already under a licence obligation to prepare and publish complaint handling procedures, and to have them in place as part of our (currently voluntary) ombudsman arrangements. We do not believe that a new Guaranteed Standard is necessary at this stage but accept that regulation may need to be introduced if these arrangements prove to be ineffective.

Customer Service Reward Scheme (App7 1.31)

We support Ofgem's desire for best practice, as identified during DPCR4, to be adopted by all DNOs. Of the two options presented, we consider that Option 1 would be the most effective way of achieving this. We believe that option 2 *'Incorporate best practice into the licence',* would be difficult to implement as the subjective nature of some of the best practice criteria could lead to different interpretations of what is required.

Guaranteed standards

We accept the proposed change to compensation levels to take account of inflation and support Ofgem's decision not to increase the levels of compensation beyond this.

Question 4: Do you agree with our proposed approach to connections, which of the options do you support and why?

We do not agree with Ofgem's diagnosis of current performance, and hence its justification for introducing a substantially increased regulatory burden.

We note that Ofgem categorises Authority determinations as a "category of complaint" (Table 3.2). This is misleading because determinations often concern a difference of view and are rarely about poor service. Similarly, it is not clear that the requests for "informal advice" represent complaints.

Furthermore, although (in Ofgem's table) connections represent the biggest category of referrals to energywatch (323 of a total 878 – 37%), Ofgem should not be surprised as connections are the most routinely complex area of customer engagement. 323 complaints over 30 months are just 11 per month, compared to an average number of connections made per month in 2007/08 of 42.3k – i.e. a complaint rate of just 0.03%. Ofgem's proposals to introduce more regulation in the connection area do not seem to pass the "proportionality" test.

Margins

As one of the DNOs who have been asking Ofgem to allow margins on connection work, we are pleased to see that Ofgem has revisited its previous position.

We agree that margins are only applicable on contestable work where there is, or there is the prospect of, real competition. We agree that currently this would exclude service-only work up to four domestic connections, but margins should be allowed in all other categories of contestable work.

Ofgem's choice of a three year period in which to test the market response to DNO margins on contestable work seems overly conservative, particularly in view of the current (and likely to be protracted) downturn in the construction industry. We believe that Ofgem should review the policy at the next price control review, DPCR6.

Ofgem should not include non-compliance with licence conditions in its competition tests because it provides no evidence of the state of competition, and in any case the denial of future margins on this basis would introduce a double jeopardy on DNOs with the statutory arrangements for financial penalties.

Ofgem is proposing price regulation for market segments where competition is unlikely to be effective, but has not explained why the protections that have been in place since 1990 – Ofgem determinations/escalation to consumer councils (later energywatch, and now an ombudsman service) – are now no longer appropriate. Ofgem simply has not made the case for introducing SLC15 obligations to all connections, nor has it made the case for introducing price regulation for market segments where competition is unlikely to develop.

In particular, the SLC15 target timescales were arbitrary and were applied to a relatively small number of connection applications. Extending the scope of SLC15 to all connections would introduce significant cost implications as well as the risk of non-compliance, particularly regarding unforeseen increases in connections activity. The cost impacts of these new proposals are likely to include at least some of the following:

- A need for significantly more design and quotation resources, thereby adding costs to the overall process and increasing customers' prices
- Some of the Electricity Guaranteed Standards could become redundant as a result of the new standard licence condition and would need to be reviewed and revised.
- We would need to operate the same arrangements as for SLC15, including:
    - clock start, pause, stop events – clear definitions
    - customer opt-out provision
- The scope of any new standard licence condition should match the scope of the new A&D charge regulations i.e. they should apply only where the requirement for upfront A&D charges can be applied
- It would be essential to allow a process of phased or deferred implementation of any such standards to allow for lead times on:
    - recruitment and training of skilled design resource (also needed to some extent for contract designers)
    - process and system developments to deal with changes

As a result we are likely to introduce greater levels of conditionality into our connection offers to allow for cost variations beyond relatively simplistic base estimating assumptions. We do not believe that such an outcome would be in customers' interests. Ofgem should justify its proposals against its better regulation objectives. If it cannot do this, it must withdraw its proposals.

The reintroduction of A&D charges would remove many speculative connection applications which would make the introduction of some limited additional protections more acceptable. It would therefore be helpful for Ofgem to expedite the initial work on the development of the relevant secondary legislation.

Appendix 7

We believe that the most important market tests are as follows:

- Market share
- Market penetration
- Customer awareness of competitive alternatives
- Facilitation of competition
- Compliance with SLC15

It is important for Ofgem to develop, prior to the start of the DPCR5 period, very clear and detailed guidelines, criteria etc, for how each of their tests will be expected to operate. Depending upon the final list of market tests that Ofgem adopts, we believe that a level of 70-80% achievement should determine whether a DNO can earn competitive returns.

Options 1-4 for protection of customers selecting non-competitive connections

Option 1 - LC15 standards for all non-competitive work

Ofgem needs to demonstrate more clearly the case for applying SLC15 standards to all DNO connections.

Option 2 – price-regulated segments where competition is unlikely to ever be effective.

We do not support standard pricing mechanisms on the basis that there is sufficient price protection for customers through the Ombudsman and the Ofgem determinations route. An alternative to price capping could be a more formal review by Ofgem of DNOs' prices as a part of its annual process for reviewing and approving DNOs' connection charging methodology statements. Other options could include benchmarking and/or published comparisons of DNO's prices.

Option 3 – price accuracy scheme

1.20. We do not support this option and believe that customers have sufficient protection through the established process for Ofgem determinations.

Option 4 – A cost-efficiency incentive on connections

1.21. We do not support this option as we believe it would be difficult to operate, essentially because any such mechanism would need to take full account of the variability in customer-driven enquiries, offers and connections.

Question 5: Do you agree with the proposed amendments to the IIS (in full) and what are your views on how incentive rates should be structured?

Our views on the various aspects of the IIS are set out below.

Approach to target setting

We support the use of assumed HV CI benchmarks in determining the HV CML for those companies which are frontier CI performers. We believe that companies which are frontier CI and CML performers are disadvantaged by the current process. In a number of cases these companies are being asked to accept targets that are harder than the benchmarking process indicates they should have. Under the current approach there is no incentive for being a frontier CI or CML performer apart from harder targets which are more difficult to outperform. This seems unfair. A possible option to address this would be to use the 2009/10 targets as the starting point for the glide path to the 2014/15 targets to recognise this out-performance.

Exposure to incentives

In the past, IIS has provided a strong incentive to DNOs to apply automation and/or remote control technology to their networks as part of an overall quality of supply improvement strategy. This has been very effective in cost-effectively reducing CIs and CMLs, and customers have undoubtedly benefited as a result. However, there is a natural level of saturation for this technology beyond which further incremental improvements in quality of supply become increasingly less cost-effective: a classic "diminishing return" scenario. Similarly, cost-effective "opex" solutions, such as deploying dedicated rapid response teams, can be very effective in reducing restoration times (and hence CMLs) but, once fully established, further improvements in "physical" response times become increasingly less cost-effective.

It follows from the above that further incremental improvements in quality of supply indices are unlikely to be cost-effective or consistent with customer WTP criteria. It is in this context that we believe that the DPCR5 CML targets for EPN, and especially SPN, are too stretching. The fact that we are making good progress towards our DPCR4 CI targets for all three networks is testament to the cost-effectiveness of our automation and remote control technology (and other technological improvements). Further inroads into CML reductions will require

step improvements in network reliability (i.e. reducing fault rates), which is likely to be either unduly expensive or impractical.

Under the current IIS mechanism, up to 3% of revenue is exposed to CI and CML performance. Our concern is that as Ofgem progressively tightens the targets, the impact of large events grows. While this risk has been present in the current period, the combination of the tightening of the targets with an increasing investment programme means that the likelihood of such an event is greater and its impact more significant. However, as Ofgem has recognised, the impact of these events can be mitigated. Of the options presented we would favour applying a weighting to 132kV and EHV incidents. This is administratively the least burdensome and the simplest to apply. Our initial view is that a 50% weighting should apply. If this change is implemented, we would favour continuing with the current 3% of revenue exposed. If it is not implemented, then we believe that the revenue at risk should be reduced to 2%.

We also note that there is a suggestion that CIs should have a lower weighting than currently. We do not agree. The results of Ofgem's customer survey (Figure 3.1 in the consultation document) indicate that customers place a greater premium on the reduction of cuts than their duration. In addition, while it is true that if a company reduces CIs it brings with it a CML improvement, this is not the prime driver of such investment and other options such as operational response improvements can have a greater impact on CMLs. In our opinion, CIs and CMLs should be equally weighted. We believe this strikes a balance between recognising customers' relative priorities and also recognising that CI initiatives carry a CML benefit.

Duration of the IIS Scheme

In p3.41 Ofgem asks for views on how past and future capex targets should be incorporated into setting targets for DPCR5 and beyond.

In suggesting this Ofgem is implicitly asserting a link between capex deferred and quality of supply performance. However, this is misguided because:

- capex is dominated by work on 132kV/EHV assets which contribute little to interruptions performance (because of the high levels of redundancy built in); and
- the majority of interruptions are caused by the condition of the cable network (and there is little scope for cost-effective cable replacement) and tree cutting (which is opex).

Indeed, Ofgem also asserts that "future targets would only be at existing levels or tighter, except under exceptional circumstances" (p3.41). However, an ageing cable network is bound to experience increasing fault rates and should only be replaced when there is a positive cost benefit for doing so. Therefore, in the future, relaxing quality of supply targets could well be in customers' overall interests.

Clearly these ideas need further thought.

Incentive rates

As we have previously stated, we believe that the overarching principle should be that the same percentage of revenue should be at risk across all DNOs. On this basis we do not believe that Ofgem's examples 2 or 4 are viable. In fact, we do not see a rationale for changing the current mechanism if 132kV and EHV events are appropriately weighted in the IIS mechanism. The largest incentive rates tend to be for those companies with the smallest absolute performance, and for those companies, large one-off events can have a disproportionate impact on annual performance. Therefore, if these events are appropriately treated in the mechanism then we would favour continuing the current approach.

We also believe that Ofgem's example in comparing the IIS incentive rate with the capex incentive rate may be flawed. For a company to have an incentive rate of £300k, this would imply that its absolute level of performance is low, and hence it is an above average performer. Consequently, one would expect that its marginal cost of improvement would be quite high. Similarly, a company with an incentive rate of £75k would tend to suggest a relatively high level of CI absolute performance i.e. a below average performer and hence greater scope for CI improvement at a lower marginal cost. Therefore, unless DNO A and DNO B have a similar ranking benchmarking process, which seems unlikely, the comparison is misleading.

Question 6: Do you agree with our proposed long-term objective of DNOs being able to automatically know which of their customers are off supply and the exact times, and if so what is the appropriate timescale to achieve this?

We agree that in principle, this is a sensible long-term objective.

As Ofgem is undoubtedly aware, the question of establishing full customer connectivity was discussed extensively (in 2001) with the DNOs as part of the introduction of the Guaranteed Service Standard covering multiple interruptions. At this time, the companies and Ofgem agreed that the cost of establishing phase connectivity for LV networks could not be justified –

meaning that automatic payments for multiple interruptions were not viable. Nothing has happened to change the position reached in 2001.

However, the introduction of Smart Metering would change the picture, provided that the specification provided the necessary functionality. In this regard, the ENA recently met with DECC officials to discuss DNO smart metering "requirements", and the extract below summarises the discussion on power outage detection.

"Power Outage Detection - an important customer benefit would arise from the capability of the SMS to signal loss of energisation. This would enable Network Operators to immediately identify faults on their Low Voltage networks without relying on customer calls. Also, if both de-energisation and re-energisation signals are time-stamped, this would enable Network Operators to accurately report 'Customer Interruption' and 'Customer Minutes Lost' information to Ofgem, and would enable the automatic identification of Guaranteed Standard of Service (GSS) supply restoration failures. Under severe storm conditions, the ability to ascertain the energisation status of a meter would enable the identification of 'masked' faults (i.e. where, typically, a high voltage fault has been repaired and the network re-energised, but an undetected downstream low voltage fault means that some customers remain without power). This functionality would be particularly beneficial in identifying vulnerable customers who have been without power for a long period."

EDF Energy fully supports the ENA position as stated above. However, the availability of power outage data implies a range of costs which would need to be funded, for example IT development costs to enable the accessible storage of high volumes of metering data and the appropriate processing of signals within network management and control systems. There would also need to be new processes to enable us to maintain up-to-date metering asset databases, for example to log each change of meter made by the meter operators. We have not included any costs for these aspects in our business plans and would therefore need to resume discussions with Ofgem if and when the requirements crystallise.

Question 7: Do you agree with the proposed focus on worst served customers and which of the options do you prefer?

Defining the worst served customer

We agree that it is appropriate to define worst served customers in relation to a maximum number of incidents that a customer should experience over a three year period. Such an approach will ensure that the service experienced by the worst served customers does not significantly diverge from that experienced by the "average" customer.

Defined allowances for worst served customers

Ofgem's proposal to cap the cost per customer relating to worst served customer improvements may not actually achieve the outcome of ensuring that the differential between the worst served and the "average" customer does not widen. There is a risk that the customers at the tail of the interruption distribution will continue to see a growing gap between their performance and that of the average customer.

We also do not agree with Ofgem's proposal to split the allowance equally between DNOs. In setting a minimum threshold target the allowance should be based on the number of customers in each DNO area that meets the worst served criteria. Under Option 1 EPN would be allowed approximately £300 per worst served customer, whereas SPN would be allowed £160 per worst served customer, even though it has nearly twice as many worst served customers as EPN. This is clearly inequitable, and on this basis we believe that Option 3 (varied allowance based on the number of worst served customers) is the only credible option.

Worst served customer mechanism

We support the principle that the cost per customer should be assessed at the portfolio, rather than the project, level. However, at this stage it is difficult to determine the threshold for average cost per benefiting customer without further work on the range of schemes to be implemented. In addition, while we believe it is sensible for DNOs to regularly report on their progress, the framework should be constructed so that it minimises the reporting burden.

Question 8: We have raised some detailed questions throughout this chapter and the appendix. We welcome views on these issues.

Treatment of pre arranged outages

We believe that the inclusion of cost allowances for pre-arranged interruptions is worthy of further investigation. Our main concern with it as an approach is how Ofgem would determine the appropriate level of costs. This is particularly pertinent given the inherent network differences that can impact on each company's requirement for outages to undertake work, and differing customer expectations with regard to their willingness to be interrupted for planned work.

Treatment of severe weather events

We can see no rationale for Ofgem tightening the current severe weather mechanism as a result of increased investment. The mechanism is in effect self-correcting in that, as companies invest more in improving their network

resilience, fewer events will meet the current thresholds and hence fewer CIs and CMLs will be excluded from the IIS mechanism.

Chapter 4: Networks

Question 1: Have we identified the right behaviours for DNOs? Are there others which should be included?

The behaviours Ofgem has identified seem broadly appropriate, subject to the comments we make below.

We particularly support making decisions on the basis of whole life costs – something which we strive to do. Past price controls have not encouraged this, particularly through the setting of opex allowances without robust consideration of opex capex trade-offs. Ofgem's intention to equalise incentives between capex and opex should help encourage a more robust approach.

As evidenced by Ofgem's LENS final report, it is difficult to be sure of the long-term requirements of customers since a very wide range of possible outcomes are possible as a consequence of the government's energy policy and other potential change agents over the longer term. What is becoming clear is that Britain's electrical energy profile will have to change, i.e. in terms of the way in which electricity is both produced and consumed, and hence the way in which electricity is transmitted and distributed. Massive injection of wind generation into transmission networks, increasing levels of distributed generation (including micro-generation); the gradual, but inevitable, electrification of heat and transport; and the roll-out of Smart Metering to residential and SME customers will give rise to changes to customers' usage patterns and requirements for supply quality.

Insofar as we can predict them, we should therefore reflect these changes in our network design standards and technical equipment specifications. Even so, there will remain a significant level of uncertainty in the direction and speed at which one or more of the LENS scenarios (or one or hybrids thereof) will roll out. It therefore seems sensible for DPCR5 to include re-opener(s) in respect of possible changes implied by medium-term developments, including possible changes to legislation.

To that end, while we cannot predict the future with any great certainty, we agree that it is sensible for DNOs not to necessarily replace assets on a like-for-like basis where a degree of "future-proofing" can be built in at a reasonable cost. We have been following such an approach for some time and believe that we are relatively well placed to facilitate change. For example:

- We have for some time been equipping HV GM and PM switchgear with remote control and (selective) automation functionality. This has

resulted in significantly higher unit costs (in particular, the cost of the RTU and the GPRS communication systems) but has also provided for improved quality of supply.

- Monitoring power flows on our HV and LV networks will be an important enabler of a more active network management regime going forward.

However, such steps can only be the first ones. We also need mechanisms to promote and fund innovation and to support the process of trialling and commercialisation of new technology. It is one thing to experiment with new equipment in "laboratory" conditions. It is quite another to have a readily available product which can be deployed routinely in operational situations. The DPCR4 Innovation Funding Incentive (IFI) was a welcome beginning, but stopped short of supporting the essential stage of trialling and commercialisation. Examples of technologies being developed by EDF Energy which need to progress beyond research and development include:

- AuRANMS (autonomous regional active network management system): an IFI project currently being undertaken in conjunction with Scottish Power, Imperial College and University of Strathclyde. This is a radical development of the concept of "automation" involving far greater reliance on real-time system intelligence and processing power. The concept is that a defined network cell (typically embracing two or more Primary substations and their associated HV networks) will self-reconfigure as necessary, not only for fault conditions but also to optimise distribution paths for both demand and distributed generation. The project is currently at the laboratory stage of development but we would expect to be in a position to field trial the system during DPCR5.
- Active (network connected) Electrical Storage: in future, this might be particularly valuable in terms of increasing network headroom for intermittent distributed generation and potentially enabling such generation to make a greater contribution to system security. An IFI funded "proof-of-concept" sized active storage system is currently being installed on an HV network, close to an existing small wind farm, for technical evaluation. Depending on the results of this trial, during DPCR5 we would expect to be in a position to begin trialling larger "system-size" installations which could have a material impact, both on network optimisation and in terms of enhancing the effectiveness of intermittent generation.
- Active Voltage Control is a technology that has already been trialled on our network and registered as an RPZ. However, we are now considering

extending this concept to a "system wide" active voltage control scheme. This would involve real-time management of voltage and power factor (and hence power flows) on an interconnected EHV ring network which already experiences varying levels of export from an existing industrial CHP installation and which is the subject of a number of enquiries from wind farm operators.

- Performance: this strategy has been helpful in preparing our networks for a future more "active network management" regime

We are already well placed in terms of being able to monitor power flows at the 132kV/EHV/HV voltage transformation levels and we are now considering opportunities for specifying additional measurement functionality at the distribution substation (HV/LV) level for new unit substation purchases.

It is unclear what "investment should be at a sustainable level" actually means; indeed, the word "sustainable" can mean many things including carbon neutral. If sustainable means fit for purpose, then this should be made clear. If "sustainable" has environmental connotations, then it should presumably apply to all of a DNO's obligations, and not just to investment.

Similarly, it is not clear what a "sustainable workforce" actually means. Presumably Ofgem means, invest in skills development/recruitment to ensure that a DNO can continue to deliver on its obligations. This should be made clear.

Elsewhere in its document Ofgem is encouraging the DNOs to take steps such that at least they do not become a blocker to the development of a low carbon economy – so it is surprising not to see this as one of the defined DPCR5 behaviours.

The word "development" (in "support innovation and development") is equally vague. If it means, support the transition from innovation through trialling and commercialisation to operational deployment, then we would wholeheartedly support this behaviour. However "development" can also mean economic development, social development etc. Clarity is needed.

DG/DSM offset

Ofgem mentions use of DG and DSM to offset capital expenditure in its paper, but does not refer to them in its list of desired behaviours. Elsewhere in this response we express concern that Ofgem is expecting the DNOs to offer new services without recognition of the need to fund the costs of administering them, or indeed with any debate about who is best placed to provide these services.

If DNOs are to be required to provide these services, then it seems sensible to recognise these services in the behaviours as the basis for providing equivalent price control treatment to other more established DNO services, such as providing connections.

EDF Energy believes that DNOs may well have a future role in more actively controlling both demand and embedded generation export in order to better "balance" their networks. We foresee the emergence of two important aspects of network balancing in the future.

Firstly, increased levels of penetration of distributed generation will introduce new power flows potentially requiring local network reinforcement, even where there is an upstream demand offset. Since much of this generation is likely to be intermittent, in particular wind and heat-led CHP (or CCHP) and wind, its contribution to system security (as determined by P2/6 and ETR130 and 131) will be minimal. It follows that little, if any, avoidance of upstream reinforcement will be feasible. However, this intermittency also means that reinforcing the network to provide for the most onerous maximum export/ minimum demand might not be justified in economic terms. Instead, it might be more efficient to provide for a more typical export/demand scenario and employ generation curtailment (or possibly electricity storage) to cater for atypical conditions.

Secondly, the inevitable electrification of heat and transport as a consequence of the government's renewable energy and carbon emission targets will again introduce new demand profiles for which some network reinforcement may be necessary. However, electrically heated homes (for example, zero carbon homes from 2016) and electrically powered vehicles (or plug-in hybrid vehicles) will also provide opportunities for short-term energy storage. If adequately controlled, the demand profiles for these new sources of electricity consumption could be smoothed to avoid excessive reinforcement and minimise variable losses.

Taking these two together, it is clear that local network balancing through generation curtailment, storage dispatch and DSM could become an important aspect of distribution network management in the future. Moreover, given the very high levels of wind generation that will be connected to transmission networks in the future, and the inherent challenges that GBSO will then face in terms of system balancing, it may be that DNOs will also have an important role to play in providing an ancillary service to GBSO by managing import/export levels at GSPs.

Ofgem's LENS project final report provides an insight into the scenarios that could emerge by 2025 and 2050. While the five scenarios presented provide for a very wide range of possible outcomes when viewed from a purely environmental and economic (rather than political) perspective, it is clear that the current direction of the government's renewable energy strategy will lead to a need both for high levels of transmission investment and for distribution networks to be more actively managed in future.

In view of the above, we would suggest that a far more considered and integrated approach to "DSM" needs to be developed. Such an approach would consider the respective roles of suppliers, DNOs, TNOs (and GBSO), potential new players such as aggregators and virtual power plant (VPP) operators, and not least customers. An important outcome would be the development of a regulatory and commercial framework that would enable all of these players to interact in an effective and co-ordinated manner such that the government's renewable energy strategy and carbon emission reduction targets can be delivered in time, and at a reasonable cost, and such that customers are able to benefit financially from Demand Side Participation

Question 2: What action should we take where a DNO has deferred investment and created a backlog in DPCR4?

We understand the principle that DNOs should not benefit from inefficient deferral. However Ofgem will need to be careful in how it applies the principle because, if a crude approach is taken, efficiency incentives will be undermined. In any case it would not be in customers' interests for DNOs to incur expenditure which, due to previously unforeseen circumstances, subsequently proved possible to defer (for example, if anticipated load growth had not materialised at a particular network node or the condition of a given asset had not deteriorated to the extent expected). Equally, it would not be in customers' interests for DNOs not to bring forward investment the need for which had previously been unforeseen. Such flexibility is a necessary component of efficient network investment management which the IQI mechanism is ideally suited to facilitate. Ofgem should not be overly concerned that DNOs are benefiting unduly from the incentive.

Moreover, Ofgem seems to be suggesting that the deferral of investment during times of high commodity prices is not in customers' interests and should be funded by shareholders. However, deferring investment to a later period when cost levels have reduced will benefit customers through lower charges in the long run. Customers, had they the means to express a choice, may choose a small and short-term increase in risk as a fair trade-off. DNOs are in a position

to make this judgement on behalf of customers, whereas if commodity price risk is passed through to customers (as Ofgem is suggesting), no choice can be made.

Ofgem's statement in p4.23 that it will take opex overspends into account when evaluating capex underspends, is sensible and welcome.

Question 3: What approach should we manage to deal with volume uncertainty?

We agree with Ofgem that current economic uncertainty makes it difficult to accurately forecast demand requirements. We also agree that the existing volume driver, based on p0 values, units distributed, and customer numbers, is not a particularly good proxy for load-related investment and that an alternative needs to be developed.

Any new driver needs to be relatively easy to define and measure. One possibility would be the annual peak demand for a network, or perhaps at a defined set of nodes. However, this measure can be rejected as it would not deal with load churn (i.e. movement of load between areas as one prospers but another suffers relative decline) – an important driver of LRE capex. There would also be issues with timing, since load growth may initially be accommodated on lower voltage assets with relieving upstream (EHV/132kV) reinforcement following on in later time periods.

In implementing a new driver, Ofgem will need to consider interaction with the IQI mechanism. In the current environment, where the potential impact of the credit crunch is unfolding daily, it would be quite unreasonable for a DNO to have reduced incentive opportunities simply because Ofgem took a more pessimistic view of the economy (and hence load growth) than the DNO, particularly when the price control is to be de-risked by the use of load-related drivers.

Integration of the IQI with load triggers may need DNO LRE capex forecasts to be normalised to a baseline view of economic activity agreed with Ofgem. This would also need to incorporate a baseline view of the proportion of costs related to connections and to reinforcement. Differences in volume assumptions (between Ofgem and the DNO) would therefore not form part of the IQI assessment.

Revenue increments for use with the capacity installed driver could be extrapolated from the baseline values in respect of each of the main voltage levels. However, this needs to be done with care to ensure that the variation DNO revenue is at least consistent with changes in their underlying costs. This needs to take account of:

- **Non-MVA driven reinforcement:** The fact that some elements of reinforcement are driven by factors other than MVA growth. Examples of this include the need to maintain fault levels and to maintain voltage within statutory limits – both of which are driven by the type of load connected to the system rather than the absolute level of that load
- **Lumpy investment**: As has been acknowledged in transmission pricing methodologies, It would be inefficient to upgrade network components in small increments (e.g. 1MVA at a time), meaning a small increment in MVA may trigger a larger increment in capacity:
- **Costs vary by project:** The cost of each upgrade reflect the specific environment of the component to be upgraded – so do vary on a "per MVA" basis
- **IQI Interface:** that the IQI incentive rate should apply equally to baseline and incremental allowances.

The scope of costs associated with a driver should include the relevant direct and indirect costs.

Question 4: What approach should we take to price uncertainty?

We continue to believe that DNOs are better placed than customers to manage the impact of input price (RPE) changes, although we note that scope for efficiently deferring work out of high cost periods will be constrained by the need to achieve defined outputs – although we would be concerned if this was the case. We agree that there is merit in developing protection beyond a trigger point – i.e. the point beyond which cost increases would jeopardise a DNO's ability to finance its activities.

Question 5: Should we be looking to equalise incentives for opex and capex? If so, what approach should we adopt?

We support the development of equalised incentives for capex and opex. As Ofgem is aware, we continue to believe that there are significant differences in the way companies report their costs under the RRP and that distortions are occurring as a result of the current differentials.

Our preference would be for all direct costs, engineering indirect costs and network investment support costs to be treated in the same way, as this would address the key boundary issues of:

- Faults/asset replacement capex

- Engineering indirects and investment support costs/capex (by contractors)

We note that negative DUoS charges to generators are an intended outcome of Ofgem's Structure of Charges project, but that at present more attention needs to be given to the accounting/price control treatment of these payments. We presume that these would need to be treated in the same way as more targeted payments for DG/DSM support and shown as a cost in the DNO's books (and not as a credit against DUoS income). This suggests that such costs need to be included in cost allowances and thereby in price controlled revenue. Where a payment to DG is specifically to defer a reinforcement scheme, then the capex allowances for that scheme can be used to fund them. However, no such relationship will exist for payments made in respect of an LRIC-based tariff, since the investment deferred will, in many cases, relate only to a notional load increase.

We assume that since capex incentives are symmetrical (unlike the current opex incentive), any enlarged incentive would also be symmetrical. It is important with regard to clearly understanding the package on offer that Ofgem confirms this point.

Question 6: Do you consider that we should make refinements to the IQI? If so, what changes should we make?

Bidding

For reasons which appear somewhat speculative (that Ofgem's benchmark can be affected by the DNOs bidding), Ofgem says that it has improved the IQI by not allowing DNOs to make changes to the initial forecasts they submit. However, since the incentive matrix has not been published it is hard to see how the DNOs are able to react to them if rebidding is not permitted – thus destroying the incentive.

Ofgem's decision also allows it to set IQI amounts below the level of any reasonable forecast, whilst insisting that the DNOs remain committed to their forecasts – another example of increased regulatory risk.

Connection charges

Ofgem expresses concern about the increase in connection charges seen in DPCR4 and suggests that, in DPCR5, incentives be adjusted so that variances from plan have no impact on incentives (p4.19).

We believe this to be unnecessary. At DPCR4 there was considerable uncertainty in this area. In particular, at Ofgem's instigation, DNOs made a

number of far reaching changes to their connection charging policies (such as the removal of tariff support and capitalised operations and maintenance, and the introduction of cost apportionment factors). We are not aware of any equivalent policy changes being proposed for DPCR5, and therefore, Ofgem should be able to gain confidence in DNO forecasts by reference to charges made in the DPCR4 period.

The capex incentive sends a strong signal to DNOs to optimise each charge within the context of their respective charging policies, hence sending the most robust marginal and locational price signal. This protects existing users from bearing costs which should rightfully fall on the person making the decision to connect. Removing this incentive would be a retrograde step in our view.

Scope of costs

The scope of costs included in the IQI should be the same as those covered by a unified incentive rate (see our response above).

Load related expenditure (LRE)

In p4.47 Ofgem refers to its intention to develop LRE volume drivers/triggers (connection volume, reinforcement, high materiality projects). There are important interactions with the IQI to consider. Clearly, these are intended to de-risk allowances with regard to differences between the DNOs' forecast and actual events and it would then be inappropriate to penalise a DNO though the IQI mechanism for having different assumptions of load development to Ofgem. The implication is that in determining a base level of LRE, Ofgem and the DNO will need to agree a shared view of base load growth.

Question 7: What action should we take where DNOs provide insufficient output information as part of their February FBPQ?

Ofgem's response should be proportionate to the risks involved and, in particular, should not jeopardise an efficient DNO from being able to finance its functions.

Question 8: Do you agree with our proposed approach to assessing network operating costs and indirect costs?

We are pleased to see that Ofgem intends to take a robust approach to regional costs. We believe that in the interests of fairness Ofgem must make symmetrical adjustments i.e. uplift the costs of those companies who operate in lower cost areas to the national average as well as reduce the costs for those companies who operate in high cost areas. Not do so could result in high cost area companies being unfairly discriminated against if a company in a lower

cost area sets the benchmark as they cannot feasibly achieve that target without moving their network to that lower cost area.

Ofgem should take care in the use of cost benchmarking and interpretation of the results. All benchmarking can do is reveal differences in cost levels not explained by the drivers used. It cannot reveal any particular level of efficiency. Ofgem therefore has no basis to assert, as it has done in the past, that the costs of one or more "frontier" companies are appropriate for the others.

Ofgem's DPCR4 benchmarking (and assertion of a 1.5% frontier shift) were clearly wrong given that most DNOs have exceeded their opex allowances. Ofgem's statement that comparative analysis will play a key part in the review (p4.24) is worrying and suggests that lessons have not been learnt.

There is a fundamental inconsistency in Ofgem wanting DNOs to be more innovative and flexible whilst at the same time asserting cost reductions by drawing inappropriate conclusions from benchmarking.

Cost allocation categories

We support Ofgem's allocation of cost categories into its three approaches – statistical (regression, DEA etc), bottom-up review and expert review – provided that an over-arching check is applied to ensure that the resulting cost allowances are viable and do not represent an impossibly efficient virtual DNO. For the statistical element an aggregate, top-down view should be used as a check. However, this is not possible with the bottom-up and expert elements, in which case Ofgem must ensure that any large differences between modelled cost and recent past costs can be justified in terms of credible management actions (such as cost reduction programmes).

We agree that Ofgem has "made significant progress in identifying and resolving inconsistencies in the [DNOs'] data". However, as we have discussed with Ofgem on many occasions, there remain material problems with the data. If, for example, some DNOs can fix faults for less than our costs of ground excavation alone (costs discovered through competitive tendering) then problems remain. At this stage, Ofgem should make adjustments to DNO data where it can but otherwise remove abnormal data points (high and low) from its analysis.

We are pleased to see that Ofgem intends to take a robust approach to regional costs.

Related party margins should be included (unless excessive) in respect of parties appointed following market testing or competitive tender, i.e. where the resulting costs to the DNO (including the margin) represents the efficient cost.

Normal pension costs should be included to enable robust comparison with contractor costs. Where a DNO has made lump sum payments into its pension scheme(s) which go beyond deficit repair, its pension costs should be suitably normalised.

An allowance for atypical events should be included, based on national average annual cost. The risk of any additional costs should be reflected in the (also national) cost of capital for DNOs.

With regard to normalisation adjustments, we have identified adjustments relating to operating in London specifically, and to the costs which result from urbanicity, and super-urbanicity more generally. These factors are routinely taken account of in international benchmarking studies, including more recently those carried out for the French regulator (CRE).

We agree that the non-op capex should be spread over the relevant activities to reduce in-sourcing/out-sourcing decisions. As non-op capex is variable year on year, longer run averages should be used in the analysis.

We agree that costs should be adjusted to reflect in-sourcing/out-sourcing decisions as far as practicable.

We are pleased to see a cost driver relating to investment activity – an omission which greatly undermined the DPCR4 analysis. The other drivers also are intuitively sensible, although they will themselves be insufficient to explain cost variations between the companies. For example, benchmarking fault costs against a single variable (fault numbers) cannot possibly capture costs associated with the difficulty of finding, reaching or accessing the location of the fault beyond the basic overground/underground split. For example, in London there are costs associated with travelling time (congestion), removal of parked cars, gaining permission to access streets etc.

With respect to the measure of network activity, consideration will need to be given to the different weightings between the DNOs regarding Network Investment and Network Operating Cost Activity. The driver for vehicles and HR should be an FTE-based metric.

We note that the cost Ofgem intends to exclude from the scope of the regressions etc. covers a significant part of the average DNO cost base – although this varies considerably between the companies, no doubt reflecting differences in reporting. It will be important to understand these differences in order to produce a fair outcome.

We note that Ofgem understands the risks of using international benchmarking, particularly around data credibility. However, issues also exist around

differences in service levels, accounting practice and investment cycles, which makes robust comparison difficult.

We are concerned that in a time when DNOs are proposing substantial increases in direct capital expenditure, statistical analysis based on historical levels of activity may not provide a good indicator of a reasonable level of future indirect costs required to support this level of investment. Therefore, in determining the appropriate level of future indirect costs, Ofgem will have to have due regard to the level of future direct network investment.

Activity groupings

At a high level we believe that Ofgem's proposals in respect of Cost Groupings and Drivers are broadly sensible. We would make the following comments concerning the details:

- Underground faults – Ofgem might wish to consider undertaking the analysis both for total fault volumes and damage-only faults. We would expect damage faults to be the key driver in this area, as these faults require excavation, which is typically the largest component of the cost.
- Network Policy, Design, Project Mgt and System Mapping – We support the use of Network Investment activity as the driver, however we believe that there will need to be further discussion with the DNOs to agree an acceptable definition of this measure.
- Engineering Management, Control Centre, Call Centre, Stores, H&S and Operational Training – We support the use of a driver combining network investment activity and network operating costs. However, Ofgem may need to consider the different mix of activities and the balance between opex and capex which the different DNOs are proposing, and apply an appropriate weighting to the two components.
- Vehicles and Transport, HR and Non-operational Training – We would like to suggest that the driver proposed in the policy paper is rather complex, and that both these cost categories are essentially driven by staff numbers. For vehicles and transport, the number of direct FTEs might be an appropriate driver. For HR and non-operational training, total FTEs could be used, perhaps weighted in respect of the proportion of direct to indirect FTEs.
- Inspection and Maintenance – We believe that the cost driver should reflect the numbers of assets, broken down by asset type, on which a DNO incurs expenditure. We would expect Ofgem to adjust the costs of the Scottish DNOs to reflect the fact that their 132kV network is

considered as transmission. This issue may also affect the benchmarking of the indirect costs. We would also expect Ofgem to recognise the particular I&M costs that EDF Energy faces as a result of its legacy fluid-filled cables.

- Tree cutting – We support the use of DPCR4 reopener data to set allowances. However, Ofgem will need to be conscious of the implications that different in-sourcing/outsourcing arrangements might have on cost reporting.
- We agree with Ofgem's position with reference to the exclusion of EHV/132KV Faults and LV/HV Plant Faults from the regression analysis. It may be appropriate for Ofgem to consider setting allowances on the basis of a three-year average.
- Non-Quality of Service Faults – Ofgem may wish to include this in its regression analysis. In our view, customer numbers would provide a suitable cost driver.

Treatment of apprentice training costs in the benchmarking analysis

In our opinion, Ofgem needs to ensure that DNOs that have invested in areas such as apprentice training and other recruitment and development initiatives, in anticipation of increasing volumes of future capital works and the challenge of an ageing workforce, are in no way penalised. We are particularly concerned given that EDF Energy has invested more than the DNO average in this area, and believe it would be inequitable for us to be disadvantaged in the benchmarking for being a first mover in this area.

Question 9: Do you agree with our proposed approach for assessing network investment?

- Important to take account of regional cost difference and unique characteristics of London's network
- How do we engage – will there be an equivalent of the PB power report?
- How will Ofgem investigate the difference between the output of its models and the DNOs' submissions?

Assessment of load related expenditure

We accept that it is entirely appropriate for Ofgem to develop its own view of each DNO's required investment. However, where there are material differences between a DNO's view and Ofgem's, then it is equally important that sufficient

time is allowed to explore these differences, and where Ofgem continues to differ from the DNO, it must clearly state the rationale behind its decision. If this is not the case, then the transparency of Ofgem's process will be questionable and the outcome is at risk of being inequitable.

Load related investment

We agree with Ofgem that units distributed are no longer an appropriate driver for forecasting future load-related investment requirements, and that new drivers require development. With regard to new connections, however, we do have some concerns with employing a benchmark cost per connection approach at LV and HV. Based on our own analysis of the most recent data, there is a huge variation between the DNOs in terms of cost per connection. This would tend to suggest that significant normalisation may be required and that the use of multiple years of data should also be considered to mitigate any year-on-year volatility. The latter is particularly true of HV where the scope of schemes, and hence costs, can vary considerably. If Ofgem were to implement such an approach then it would be essential for both regional and network specific factors to be considered, thereby ensuring that the process was equitable across companies.

Given the current level of economic uncertainty, the use of triggers for general reinforcement expenditure is a pragmatic solution. However, as we have previously stated, a key element of this approach will be determining the baseline against which the triggers will operate. This will require Ofgem and the DNOs to agree a set of economic assumptions against which to forecast future reinforcement requirements. In addition, there are categories of expenditure that fall within the general reinforcement category (e.g. maintaining statutory voltage compliance), which would not lend themselves to a £/MVA driver. Further thought needs to be given as to how such expenditure will be dealt with.

Non load related replacement

Ofgem's process looks broadly sensible subject to there being sufficient time to debate the outcome. However, as with the load-related assessment, it is vital that Ofgem takes into account any regional/network specific issues.

Chapter 5: Financial issues

Ofgem's statement (in p5.1) that it "will avoid too narrow a focus on the cost of capital decision", and instead take a "more holistic approach", creates a new element of regulatory uncertainty.

Ofgem will have to clarify what a "more holistic approach means" and how it can guarantee that DNOs can earn returns that are sufficient to attract new finance. Incentive schemes may provide an alternative source of profit (or loss), but it must be stressed that the cost of capital provides the return on investment, whilst incentive schemes provide a word for efficiency or the delivery of an agreed change to outputs. The latter cannot pay for the former.

Question 1: Have your views on the appropriate methodology for setting the cost of capital or on indexing the cost of debt changed as a result of the current turmoil in the capital markets?

Yes.

We are in unprecedented times. If the market conditions do not settle down before Ofgem makes its decision on the cost of capital to be applied, then there is a real risk that if it is set with too great an emphasis on long-term trends, it is likely to be set at too low a level. This will be just at the time when many DNOs will have to raise more finance to deal with increasing investment levels.

Cost of Debt

We believe the effect of government policies to increase the availability of debt should be closely monitored in the first half of the year to see what effect the policies have on the availability and cost of debt and the wider market conditions.

In the likely event that high levels of uncertainty remain we would support some form of trigger/re-opener mechanism to ensure that Ofgem sets the cost of debt at a level that adequately reflects the costs DNOs will be exposed to. In doing so, it will be important to ensure that DNOs are incentivised to efficiently manage the cost of their debt.

We are therefore supportive of the stance set out by Ofgem in p5.13 of the Policy Document which confirms that it will retain the option of introducing a cost of debt trigger or re-opener if, when the cost of capital is set, capital market conditions remain difficult, or debt rates remain above long-term averages.

We are currently considering suitable indexation mechanisms, including appropriate benchmark indexes and possible ranges, for discussion with Ofgem

prior to the development of proposals for inclusion in the Initial Proposals document.

In the policy document (p5.12) Ofgem makes reference to its analysis being in line with the Competition Commission's September 2007 conclusion that "indexation would start to erode one of the core foundations of RPI-X regulation". We believe Ofgem should be careful in placing undue weight on this conclusion, as circumstances are currently occurring in the debt and wider financial markets which could not have been envisaged in 2007.

Cost of Equity

Ofgem sets out in para 5.7 of the Policy Document that it intends to examine a number of variables to arrive at the cost of equity, and therefore it is not currently in a position to confirm whether the range of long-term average returns of between 6.5% and 7.5% is still appropriate.

We believe that even before account is taken of the impact of the current credit crunch and wider market conditions. the range of equity returns quoted by Ofgem is below that which can be justified by an objective review of available data.

Risk Free Rate

- We believe the use of Index Linked Gilts (ILGs) as a measure for the risk free rate is biased. This bias has been primarily driven by increasing levels of inelastic demand driven by pension funds which have been switching assets into ILGs, partly to deal with the Minimum Funding Requirements, FRS17 and IAS 19 issues, which has driven a decline in real yields. In addition, in times of market volatility – such as current market conditions – yields are also likely to be depressed.
- Yields of all maturities of ILGs are affected. The Competition Commission agreed in its BAA ruling that long dated maturities were distorted and they focused on 5 and 10 year yields instead. However, if yields at longer maturities are distorted then so must be, perhaps to a lesser extent, yields at shorter maturities.
- We believe, in line with a number of academics, that the use of swap rates provides a more robust basis for determining the real risk free rate. We believe the market-based swap evidence supports a risk free rate of **2.5%** (based on 10 year swaps). This compares to an ILG yield of **2.1%**.

- A review of the international evidence from markets not subject to similar biases to the UK ILGs indicates a range on deflated yields on government bonds in the range of 2.1% to 2.8%, averaging around **2.5%**.

Equity Risk Premium

- Based on very long-term historical data for the UK, the range of ERP is between 4.1% and 5.4%. The lower end of the range is based on the geometric average and the upper end of the range on the arithmetic average. The majority of academic opinion favours the use of arithmetic averages which therefore indicates an ERP around **5.4%** is appropriate.
- The Dividend Growth Model provides a valuable cross-check to the appropriate level for the ERP. Using objective market data for each of the FTSE 100 companies (including published analysts' forecasts), it is possible to calculate a forward looking ERP. The values have been cross-checked against FTSE 350 companies and give similar results. These results indicate that the correct ERP is 5.3%, which is consistent with that obtained using the arithmetic average of **5.4%** above obtained from historical data.

Beta

- The available market data to assist with Beta estimates is limited. We believe the relevant data is in respect of National Grid, Scottish Power and the water companies and that National Grid provides the best comparator. Looking at both short and longer-term data relating to National Grid, it suggests an asset beta of around **0.37-0.42** which is broadly consistent with the water companies.

Estimated Cost of Equity

- Based on the above, we estimate that the appropriate cost of equity (before taking account of the impact of the credit crunch) is in the range of **7.5% to 8.2%**.

Real Risk Free Rate	2.5
ERP	5.4
Gearing	60
Asset Beta	0.37 – 0.42
Equity Beta	0.93 – 1.05
Cost of Equity Range (real, post tax)	**7.5% - 8.2%**

- Using the DGM as a cross-check, using data from National Grid and the water companies for 2007 and 2008, a range of 7.6% to 8.6% is obtained which is broadly consistent with the CAPM results above

Impact of the credit crunch on cost of equity

- We are currently undertaking work to assess the impact that the current financial conditions would have on the cost of equity if they continued into the longer term. We aim to share the results of this work with Ofgem prior to the development of policies for inclusion in the Initial Proposals document.
- It is clear that financial volatility has increased significantly in recent months, and during such periods, investors require greater compensation for the risks they are exposed to (i.e. a higher ERP). Initial analysis indicates that ERP had increased towards 10% by the end of November, but we are undertaking further analysis.

Financeability

In assessing the financeability of price control proposals Ofgem must ensure that the assumptions it uses to estimate the cost of capital are the same as those used in its financial models. This is particularly important for DPCR5 because one impact of the credit crunch has been to introduce large premiums for paper lower than A3/A-.

Bond yields and credit spreads

The chart below shows observed yields on A and BBB-rated 10-year bonds, and shows that the relative cost of weaker credit quality has grown significantly throughout the crisis period. Clearly, differentials of such magnitude (up to 150bps) raise important questions about what Ofgem should assume when setting the cost of capital and when carrying out financeability tests on the DNOs.

We understand that credit/default spreads are wider than has been the case in previous recessions, indicating the unprecedented nature of the current environment and the prospect of significant levels of corporate defaults to come. It seems likely that these will persist for some time, at least throughout 2009, and may lead to a more fundamental reprising of default risk (there being little price discrimination for risk during the "bubble"). Setting the price control on the basis of BBB assumptions would pose an unacceptable level of risk to us in the current conditions.

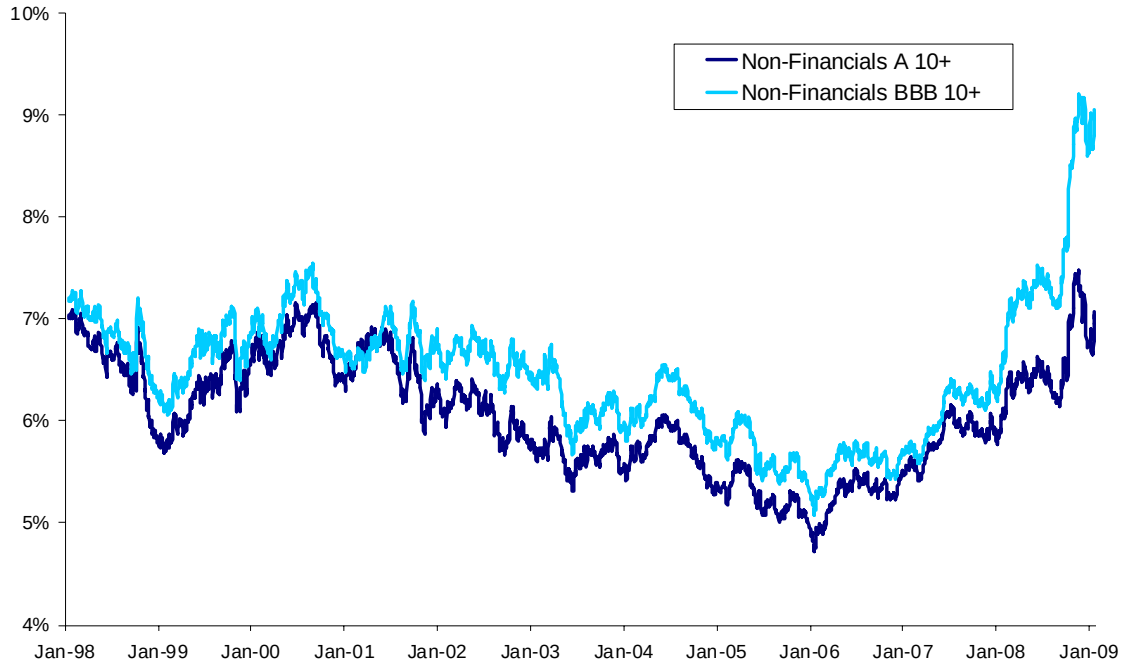


Chart: corporate bonds in the Secondary Sterling Market

Furthermore, in assessing financeability, Ofgem has been able to improve a DNO's position through assuming a proportion of index-linked debt. In DPCR5 Ofgem will need to make realistic assumptions about the availability of index-linked debt. Currently, following the demise of monocline insurance as a form of credit enfacement, the market for IL debt has all but dried up. Evidence of an enduring recovery will be needed before Ofgem can make assumptions about future use by the DNOs.

Ofgem should take a cautious approach to assuming new equity finance, either through rights issues or through retained earnings. In particular, we believe that it would be unwise to make significant changes to regulatory depreciation assumptions without being certain that the value of existing equity is not being diluted.

Question 2: What is the appropriate timing of actuarial valuations for setting ex ante pension allowances?

We believe the best option for treating pension costs is to base the allowances on the DNOs' best estimates of the costs they will incur during the DPCR5 process. These estimates should be supported by the DNOs' professional pension advisers.

Given the significance of pension costs, it may be appropriate for Ofgem to request additional information over and above that included in the DNOs' FBPQ and Pension Questionnaire submissions. We would be supportive of this

approach if an appropriate allowance for pension costs could be made in the Final Proposals.

We believe that the option of using the latest available triennial valuations on the basis that this would reduce the cost to customers in the short term, with there being a true up in DPCR6, is not a valid alternative as all the evidence points to this leading to significant underfunding of the DNO's properly incurred costs in the DPCR5 period.

The option of having a re-opener when a new regular full triennial valuation is published, which results in a material change to pension costs, would protect DNOs from significant increases in their costs but would potentially cause a sharp increase in charges at the point the re-opener was settled. This situation could also be complicated by the Trustees requesting a full formal valuation on a more frequent basis than every three years, which they are entitled to do. In addition, a re-opener mechanism will also result in increased workloads for the DNOs and Ofgem.

Treatment of Taxation

Triggers - Ex post Adjustments for legislative changes

EDF Energy maintains its support for an ex post mechanism that adjusts for material legislative changes. This reduces the risk to the DNOs of adverse changes whilst allowing the customer to benefit from favourable changes. In formulating such a mechanism there are a number of parameters that need to be defined:

- Proportion Shared: Ofgem's policy document refers to a "sharing mechanism", however this could only be appropriate when management action is possible to mitigate the impact of the change. For most changes to legislation this is unlikely to be the case. EDF Energy believes that rather than having a "sharing mechanism", the mechanism should remove all risk and potential upside from the DNOs subject to the materiality trigger discussed below. That is to say, all downside risk of adverse legislative changes should be removed from the DNOs whilst similarly the customer should retain all of the upside benefit of beneficial legislative changes. This is of course what would happen in competitive markets in response to generic changes to tax.
- The definition of legislative changes should be:
  "Any change in legislation that alters the cash tax charge for the DNO in the current price control period, and should specifically include:

- Changes in the relevant legislation whether introduced in a finance act, other act of parliament, statutory instrument or other legislative instrument,
- Changes in, or clarifications to, HMRC interpretation of legislation,
- New precedents set under case law, and
- Changes in accounting standards that have a knock-on effect on the quantum or timing of taxation."

- Frequency of calculation: EDF Energy is not currently expressing a view as to the most appropriate frequency for calculation of adjustments. It is understood that Ofgem has prepared a discussion paper that will form part of the next draft policy document and EDF Energy will respond to that document on the most appropriate frequency.
- Trigger: we believe that it is sensible to have materiality threshold so that only changes with a significant impact are addressed. The materiality thresholds used for the DPCR4 re-openers (1% of base demand revenues per category) are a sensible starting point.
- The definition of a tax-related trigger needs to recognise that a legislative change may have differing effects in differing years of a price control period. This should be calculated on the basis of the average annual effect over the remainder of the price control period. Furthermore, where a number of changes are enacted in a single act, those changes should be considered in total as a single adjustment rather than separately.
- While the adjustment to the current tax charge may be greater than the agreed materiality threshold, it is possible that the adjustment to the total tax charge, i.e. the charge including deferred tax, may be £nil and hence there would not be any adjustment to retained earnings for the year. It is therefore important to ensure that the adjustment to the tax cost allowance not only reflects the adjustment to current tax but also reflects, where necessary, the lack of adjustment to profits available for distribution.
- The trigger should not act as an "excess". That is to say, wherever the materiality trigger is breached then a tax cost allowance adjustment should be made for the entire amount rather than the excess over the materiality trigger.

- Calculating the Adjustment: the adjustment should be calculated by simply re-running the relevant model as adjusted for the specific legislative change. No adjustment should be made to any assumptions used in the model, even if these are known to be incorrect by the time the model gets re-run. This ensures that the adjustment is calculated on a like-for-like basis.

EDF Energy agrees with Ofgem that a similar adjustment for over/under-performance against the tax cost allowance is inappropriate. As stated by Ofgem, this would be a disincentive to DNOs to manage their tax costs efficiently.

Claw Back of Tax Benefits of Excess Gearing

EDF Energy responded under separate cover to the open letter on tax claw-back for excess gearing.

Modelling of Capital Allowances

EDF Energy appreciates the progress that has been made since the initial consultation in moving away from a generic approach to capital allowances. Such an approach would not result in capital allowance profiles that in any way reflected the reality of the DNOs' corporation tax computations and hence would remove any legitimacy from the calculation of the tax cost allowance.

EDF Energy has actively supported the "specific approach" which uses the actual DNO specific tax pool allocation policy. With our support Ofgem has now introduced the necessary sheet into the FBPQ that allows this data to be captured. The specific approach provides transparency in reconciling the tax calculations used to calculate the tax cost allowance to the RRP tax calculations to be undertaken on an annual basis during DPCR5.

Ofgem has indicated, however, that its favoured approach is the "common approach" which relies on an "average" actual allocation based on information received from all DNOs. While this removes the transparency in being able to reconcile actual tax calculations in RRPs back to the tax calculation for the tax allowance, it can be argued that it provides an incentive for DNOs to be more "tax efficient" than average. A DNO that is more efficient than average will receive a tax allowance based on the average and hence will benefit compared with a less efficient DNO. EDF Energy is not wholly comfortable with this approach as it does not believe that material efficiencies are available or that it is appropriate to use anything other than the specific approach. However, as a matter of pragmatism, EDF Energy would be prepared to accept the common approach provided there is clarity over how the average tax allocations are

calculated and that they are undertaken on a basis that would not unfairly favour or detriment a DNO:

- Firstly, it is important that those averages are carried out at the level of each line on the sheet F8 of the financial FBPQ rather than at the level of "Load", "Non-load" etc. This would recognise the supposed efficiencies (or otherwise) of DNOs' treatment of different types of expenditure without artificially benefiting or impairing a DNO because it incurs more or less than average of a particular type of expenditure.
- Secondly, it is important that the DNOs have sight of the averaging calculations so that it is possible for each DNO to understand why they differ from the average.
- Thirdly, EDF Energy agrees with Ofgem that it would be appropriate to exclude the "outlying" DNO from the averaging calculations.
- Fourthly, averaging should not be applied to the splits between amounts treated as capital and amounts treated as revenue for accounts purposes.

Opening Capital Allowance Pools

There is concern amongst some DNOs that if the opening values for the DPCR5 tax pools are based on actual tax computations rolled forward to 31 March 2010, then some expenditure from DPCR4 can be reflected in the allowance for tax twice, and hence artificially reduce allowed revenue. It is worth giving an example of how this can happen:

Suppose £1,000 is spent in the first year of DPCR4. For the purposes of DPCR4 Ofgem assumed that this qualified for plant and machinery allowances at 25%, whereas in reality it qualifies for long life asset allowances at 6%. In the five years of DPCR4 Ofgem will have given capital allowances of £734 and hence reduced the tax cost allowance by £220 (£734 @ 30%). This leaves £266 of allowances to be taken in later price control periods. In reality, capital allowances of only £237 will have been claimed, leaving £763 of capital allowances to be taken in later price control periods rather than the £266 assumed by Ofgem. This means that £497 of capital allowances reflected in setting the tax cost allowance for DPCR4 will also be reflected again in setting the tax cost allowance for later price control periods, and hence the overall tax cost allowance will be artificially depressed.

Clearly this does not appear to be equitable, although it is fair to state that it is just as likely that the DNO could benefit from such a situation. The alternative

is to use the closing pools from DPCR4, which would ensure that there would not be any double counting, as seen in the example above.

However, it is EDF Energy's view that it would not be practical, equitable or consistent to use the closing pools from DPCR4 and that, despite the obvious issues that surround using opening pools based on actual computations as seen above, opening pools must be based on actual submitted computations. There are a number of arguments to support this view of which the key ones are:

- As mentioned above, EDF Energy agrees with Ofgem that there should be no adjustment for over/under-performance against the tax cost allowance. This would not be consistent with using the closing pools from DPCR4 to form the opening pools for DPCR5 which effectively removes any incentive to the DNO to out-perform on negotiating relief for capital expenditure with HMRC.
- The reasons why the opening pools calculated on the two bases are different would need to be explained if going for a DPCR4 closing pool approach. This is because, for instance, the difference between the two balances may be caused by real differences in total capital expenditure. If real capex had exceeded that forecast in DPCR4 then, clearly, pool balances would be higher in reality than those reflected in DPCR4 and it would be inequitable, and damaging to the customer, if additional tax cost allowances were given in future price control periods just because this additional tax written down value was not reflected in the tax pools used for DPCR4. Furthermore, the actual process of identifying exactly what the differences were between what was forecast in DPCR4 and what was actually spent would prove very difficult in practice.

Therefore EDF Energy is of the opinion that the only practical and consistent basis for opening capital allowance pools is to use submitted computations rolled forward to 31 March 2010.

Depreciation Rates

As well as the generic splits for capital allowances used in DPCR4 (see above), a generic depreciation rate for deferred revenue expenditure of 2 1/2 % was used in DPCR4. EDF Energy believes that using real depreciation rates (as evidenced by prior year computations) is the most appropriate method for calculating relief for deferred revenue expenditure. The rate of relief for deferred revenue expenditure is as intrinsic to a tax computation as a capital allowance rate.

Chapter 6: Process

Question 1: We invite views on which format stakeholders would find most useful for the Ofgem workshops to be held in January 2009.

We supported and attended the workshops held by Ofgem during January, which we believe have been helpful to the overall process.

Question 2: We invite views on our proposed process.

In general we believe that the process as set out in the Policy Paper is robust, but we have some concerns about the volume of work Ofgem will need to complete to achieve the short-term milestones, particularly the publication of the methodology document and initial results in May. Any delay to the completion of this document is likely to have significant impacts on DNOs' ability to provide an FBPQ update by 26 June. However, we do have some specific comments regarding aspects of that process.

There has been a significant level of change between the format of the August HLFBPQ and the February FBPQ, and delays from Ofgem in finalising and communicating these changes have caused problems in scheduling our internal resources. The dual submission dates of 13 February and 27 February introduced by Ofgem in response to this issue are considered to be only partially helpful due to the inter-relationship between tables and EDF Energy's internal planning structures. This has therefore raised additional risk on a DNO's ability to achieve the necessary quality controls for the submission on 13 February. Recognition and flexibility of Ofgem's approach with regard to the correction of any data errors would be welcome.

The alignment of the FBPQ submission date and the date for responses to the Policy Paper on 13 February 13 has also been unhelpful, as it has risked diluting the focus of our resources.

We are unsure of the value of the request for a "reduced RRP" submission on 26 June followed by a full RRP submission a month later, in "late July". We are required to provide a resubmission of the FBPQ on 26 June. This will include 2008/09 actual costs and volumes, which are at a more detailed level, and we would therefore question the need for a RRP submission.

We would welcome the opportunity to meet with the Consumer Challenge Group and hear their views first hand.

It would be helpful if Ofgem could communicate how it intends to define what changes can be made by DNOs between the February and June FBPQ

submissions, or whether Ofgem intends this to be by agreement, on a case-by-case basis.

EDF Energy (Networks)

13 February 2009