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EDF ENERGY

Date 06 May 2004

Dear Nienke

EDF Energy's Response to Ofgem's Electricity Distribution Price Control Review: Policy Document and Associated Appendices.

We welcome the opportunity to comment on the above documents.

It is our strong desire for EDF Energy to work closely with Ofgem (recognising our shared responsibility for the customers connected to our networks) and to achieve a successful outcome to the review.

We are pleased to see that Ofgem has resolved many of the policy questions posed by earlier papers. This should allow greater focus on the key matters for review, some of which will require considerable joint effort by us and others to fully resolve. In particular we would wish to highlight the following views, many of which we have already had the chance to share with you and your colleagues in recent meetings:

- Ofgem's approach to benchmarking is not yet robust enough for the use of frontier performance to set cost allowances. There are many reasons for this, but perhaps the most important are that it ignores all past (legitimate and efficient) capex/opex trade offs and does not yet adjust effectively for differences in the capitalisation of overheads. As we demonstrate, total cost modelling reveals the extent of capex-opex trade-offs and the fact that the most likely opex frontier company is not frontier on a total cost basis (and by extension is not frontier on price).

- By the principles of sound regulation, DNOs are entitled to recover all the costs associated with their past ERDC decisions, including the increase in pension contributions that is now required. Any treatment of these costs that does not

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properly reflect this entitlement would effectively penalise efficient decisions, and so discourage similar decisions in future. We have provided additional reasons why the cost of ERDCs should not be excluded from cost recovery. In particular, we point out that where companies are reducing costs to keep pace with Ofgem's cost reduction glide path, there was no outperformance gain to fund the associated ERDC costs.

- We agree with Ofgem that boundary problems between the categorisation of opex and capex costs can be avoided without undermining incentive regulation or impacting cash flow. We support Ofgem's intention to carry out further work in this area and look forward to seeing worked examples.

- The proposed reduction in incentives for the deferral of capex is not the best way of incentivising accurate cost forecasts or for encouraging companies to invest (an appropriate cost of capital is the means to achieve this). We propose that variable capex incentive rates should apply depending on the degree of variation between actual cost and forecast. We do not consider that such arrangements need to be company specific or related to the scale of the expenditure involved.

- EDF Energy has submitted a detailed report to Ofgem regarding the additional costs we face from working in Greater London. To date, Ofgem only appears to have recognised the issue in respect of salary costs in LPN. Ofgem has not made any counter arguments against the other matters contained in our report, but appears to have chosen to simply ignore them. Indeed, its choice of initial composite scale variable (CSV) weightings makes matters worse by discriminating against LPN's relatively short circuit lengths per customer. Not only must Ofgem correct for its CSV anomaly, it must ensure that its process is robust and transparent by specifically addressing the points made in our report.

- Any assessment of costs will need to take account of the legitimate expectations regarding the retention for five years of net merger benefits, as would automatically be the case for mergers taking place at the start of a price control period. Achieving such equity need not take the form of adjustments to benchmarking models, but can be accommodated in setting appropriate allowance glide-paths. We look forward to seeing Ofgem's further thinking in its June proposals paper.

- Ofgem has used the Capital Asset Pricing Model (CAPM) as the basis of its initial estimate of the cost of capital and in doing so has provided much significant evidence. We have asked NERA to examine this evidence and to comment on Ofgem's use of it. NERA finds that there are a number of inconsistencies between the evidence presented and the conclusions drawn by Ofgem. NERA has attempted to eliminate these inconsistencies and in doing so arrives at a cost of capital range consistent with its estimate set out in its March 2004 analysis.

- We remain strongly of the view that as we only have limited control over rates and are acting appropriately in the valuation process, the costs should be allowed on a pass-through basis in DPCR4. Furthermore, if Ofgem wishes to apply tests to establish whether DNOs have sufficiently challenged the Valuations Office on rates it needs to set out what those tests are in advance.

- We are supportive of the proposed cash lock-up mechanism, but believe that mechanisms dealing with new and uncertain costs, as set out in the recent ENA submission to David Gray, should be introduced at the same time. This would provide a DNO with appropriate protection from such cost shocks without the need for cash lock-up for Special Administration arrangements in extreme cases.

- Progress has been made regarding the incentives on connecting distributed generation. However, we remain concerned about the impact of very large (but not necessarily very high £/kW cost) schemes. We recommend that a scale based cap be included.

- We believe that Ofgem has yet to fully appreciate the poor bargaining position that DNOs are likely to find themselves in regarding the procurement of MOP services from their competitors in the new market place (and who will be contracting directly with suppliers). In this context, we believe that the obligation to provide MOP services be removed from DNOs as any dominant provider will be subject to general competition legislation.

Attached is our detailed response, which we hope you find to be an informed and helpful contribution to the review and the forthcoming discussions.

If you have any questions or comments on this response please do not hesitate to call me on 07971152317.

Your sincerely,

Paul Delamare
Head of Price Control Review

Ofgem's March 2004 DPCR Policy Document

Form, structure and scope of the price controls

Revenue drivers

We welcome the retention of the principle to equally weight the revenue driver between units distributed and customers. We note Ofgem's decision not to introduce a capacity driver at this time.

Ofgem is proposing a change from forecast to actual consumer numbers defined by the IIP Regulatory Instructions and Guidance (RIG). Whilst we are not against the proposal to use actual consumer numbers, we do have reservations about the use of RIG to define this number. Some classes of consumers are excluded from the RIG definition and there may be consistency issues if DNOs have different approaches in how they apply the RIG to define consumer numbers. Another issue is that the move to actual customer numbers may disincentivise companies from improving the quality of their MPAN data by identifying MPANs which should be disconnected. It is our view that Ofgem will need to consider the impact of these factors before moving away from the current approach.

Ofgem is reviewing the weightings of voltage categories within the units distributed revenue driver. If EHV customers are included within the price control, as indicated by Ofgem in its March document, then Ofgem's review of weightings should include EHV customers. Consideration of weightings for different customer groupings may also prove an effective method of dealing with different consumer types, for example, Distributed Generation. EDF Energy will comment on Ofgem's proposals once they are published in June.

Price Index

Ofgem poses the question as to whether the RPI (Retail Price Index) should be replaced by the CPI (Consumer Price Index) as the price control inflator.

The CPI, which is the European standard measure of general inflation, has recently been adopted by the UK Government as the inflation target for the Bank of England's Monetary Policy Committee. The main difference between the RPI and the CPI is that the latter excludes mortgage interest. The inclusion of mortgage payments within RPI is important because they:

- are generally considered to be the largest single item of consumers' outgoings, directly impacting households' disposable income;
- give a good indication of the regional cost factors affecting DNOs, especially those located in the South-East.

Given that a significant proportion of a DNO's costs are wage related (either directly or indirectly – through contractors charges for example), and that changes in mortgage payments will be translated into wage inflation pressures, it would seem appropriate to continue to use RPI.

We also note that the standard approach to US price cap plans uses the GDP deflator, which is forecast to grow at about 2.1% in the UK. The RPI forecast is about 2.2%, but CPI only 1.5%. This suggests that continued use of RPI would be more consistent with standard US practice.

Ofgem has not included any sector specific indices as a choice, and yet any proposed changes ought to be informed through an understanding of the particular inflationary pressures that bear on a DNO's cost base.

EDF Energy strongly supports the continued use of RPI.

Transmission exit charges

EDF Energy welcomes Ofgem's decision not to change the distribution price control treatment of NGC exit charges.

Treatment of wheeled units

Ofgem's proposals to include wheeled unit revenues in the price control, and to allow recipients pass through is a sensible approach and is welcomed.

EHV charges

The costs of EHV connections are highly variable. We therefore welcome Ofgem's decision to treat any new EHV connections as an excluded service during the next price control period.

We would like to better understand Ofgem's intention with regard to the development of a revenue driver for EHV within the units distributed revenue driver. At this time we are assuming that Ofgem only intends to add an additional line to the basket of voltage category weightings referred to in your paragraph 3.12.

Non contestable connection charges

EDF Energy continues to support the development of the competitive connections market wherever genuine benefit to customers can be achieved. It is pleasing to note that Ofgem has decided not to change the treatment of non-contestable connection charges and that they remain outside the scope of the price control.

However EDF Energy does not support widening the scope of competition to include any new areas of work until the current market arrangements have stabilised further. EDF Energy's experience to date would suggest all parties, operating within the contestable framework, have opportunities to further improve delivery of contestable connections to customers.

EDF Energy supports the publication of clear charging methodologies by DNOs and will be keen to participate in Ofgem's proposed working group.

The standards of service applied to contestable connections work should be consistent for all categories of connection. These standards should be open to revision as the processes around competition in connections become better developed and in light of operational experience of the process.

Extending the scope of contestable work

In the previous DPCR consultation there was a suggestion that some aspects of network diversions might be opened to competition in the future. However, Ofgem has suggested in the March paper that network reinforcement may also eventually be considered as a contestable activity. We do not support the opening of competition in either diversionary works or network reinforcement, because:

- Both network diversions and network reinforcement comprise work on, or revision to existing energised networks. This includes a significant element of operating and working on live networks within the DNO's safety rules and under its control.
- It adds additional complexity, cost and risk for both the network operator and ICP without bringing identifiable benefits to the end customer; and
- This type of work is in no way comparable to the simple extension of the distribution network on a "greenfield site" to afford new connections.

Schedules of charges

EDF Energy supports Ofgem's view that clear, transparent charging methodologies and schedules of charges should be published by DNOs. In agreeing such schedules with Ofgem, DNOs should also be required to demonstrate that the charges are cost reflective.

Standards of service

EDF Energy agrees that any voluntary standards applied to greenfield housing developments could be applied to all new connections work undertaken by independent connections providers ("ICPs"). However, as described below, some of the existing indicative standards are unrealistic. This is because a DNO's ability to meet the standards is dependent on the performance of the ICP. For example:

- In advance of any work on site it is essential that the ICP provides a programme of works indicating the sections of network requiring live connection and the dates on which those connections are required. This programme should be regularly updated in line with the actual progress of construction on site so that site inspections and live connections can be programmed in line with ICP requirements. The absence of any such robust programme negatively impacts on EDF Energy's ability to respond to ICP connection timescales.

We believe that it is inappropriate for standards to be introduced where a DNO's ability to meet them is not within its control. Notwithstanding this, EDF Energy is keen to work with Ofgem to develop a sensible regime of standards for the connections market.

Other excluded services

We support the proposals that there is no change to the price control treatment of top up and standby charges, non trading rechargeables and other minor activities and charges. We agree that the units distributed to embedded networks should be included within the price control.

Business rates

The March Policy document confirms initial rating values (RVs) are due to be provided by the Valuation Office Agency (VOA) by the end of May 2004 and following on from this the office of the Deputy Prime Minister (ODPM) will set the poundage (or tax rate).

Ofgem states in the document that as the DNOs have the right to appeal the RV they have substantial influence over the outcome of the deliberations, although 'much less influence once the RVs are finalised (following any appeals)'.

We have been using advisors to assist us in our dealings with the VOA and our understanding of the process is slightly different from that set out above:

- We believe that following appeal we have no influence as opposed to 'much less'
- Once the initial estimates are submitted to the ODPM at the end of May the only way the charges can be influenced by DNOs is by going to formal appeal

Furthermore, it is our understanding that appeals cannot be lodged until April 2005 and the appeal process itself could take up to two years. This is some time after the companies will have been asked by Ofgem to accept the final proposals.

Given the magnitude of the rating charges companies may find themselves in a position where they are unable to accept the final proposals unless the rating element has been confirmed on a pass-through basis.

As you would expect we have been fully engaged with the rating process and we have provided information as requested by the VOA to assist them in establishing revised rateable values. We have attended meetings with them to discuss the proposed methodology and their initial proposals and are awaiting further information from them as well as clarification on some issues. We have already made progress in moving the VOA on from their initial indicative proposals.

It should be noted that the use of the revised methodology may result in disturbance in the relative level of charges between companies, with some companies seeing reductions in their charges while other companies incur increases.

We remain strongly of the view that we only have limited control over these costs (including the quantum of costs applied to the sector) and therefore we believe that provided we have acted appropriately in the valuation process, the costs should be allowed on a pass-through basis in DPCR4.

We believe as a matter of urgency, Ofgem should clarify to all DNOs, details of any tests/hurdles it proposes to use to determine whether companies have acted appropriately in their discussions with VOA and whether they have mounted a sufficient challenge.

Dealing with uncertainty, new obligations and costs

Ofgem remains unwilling to allow for future uncertainty over costs, except by agreeing that something might be done. However, the uncertainty over how Ofgem will treat future cost increases means that the price cap does not offer the firm incentive that Ofgem claims. For instance, Ofgem might agree that a DNO is bearing a new cost item, but argue that cost savings are sufficient to cover it. This would result in allowed revenues being reset prematurely to a level equal to costs.

We agree that it is important that the process and approach for allowing any costs associated with uncertainty or new obligations are transparent. Therefore, we fully support the proposals sent to Ofgem by the ENA detailing a proposed methodology for dealing with the costs arising from either uncertainty or new obligations. We believe that such mechanisms should be introduced at the same time as any “cash lock-up” arrangements (see below).

Duration of the price control

Ofgem’s confirmation that barring unforeseen circumstances the price control will last from 1 April 2005 to 31 March 2010 is welcome.

Retention period for efficiency savings

We support the introduction of five year rolling mechanisms for both opex and capex efficiency savings. We also agree that for practical purposes it is sensible for no adjustment to be made to any underspend achieved in 2004/05 in the opex for DPCR3.

However, we have identified a number of concerns with the proposed models. These are:

- **Opex roller for DPCR3:** Ofgem has stated that the incremental outperformance in 2003/04 will be calculated with reference to the highest previous outperformance in DPCR3. However, in order for this to be equitable Ofgem would have to normalise the expenditure in 2000/1 and 2001/02 on the same basis as 2002/03. Given the difficulty associated with normalising the 2002/03 costs we do not believe this to be realistic. For practical reasons, we believe that the incremental outperformance in 2003/04 should be calculated with reference to 2002/03 only.

- **Opex roller for 2005/06 to 2008/09:** the model as described has two major weaknesses.

  - The inclusion of atypical items means that the outcome of the scheme is unpredictable and hence its incentive power is severely weakened. The inclusion of atypical items within the scheme would only be appropriate if an allowance is made for atypical items in the normal operating costs of each DNO; and

  - The limiting of the total incentive payment for opex savings to the average of the actual outperformance in 2007/08 and 2008/09 would result in weaker incentives to make efficiency savings in 2007/08 and 2008/09. Therefore, periodicity has not been removed though this was one of the main reasons for the introduction of rolling incentive mechanisms.

- **Capex rollover scheme for DPCR3** – We have been unable to recreate Ofgem's proposed incentive payments illustrated in Table 3 of Appendix 1. In the example, Ofgem states that the efficiency payment in 2005/06 should be £1.34m, comprising one year's depreciation and half a year's return. However, half a year's return in the example should be £0.66m[1]. Therefore, the actual incentive payment would be £1.66m, as one years depreciation is equivalent to £1m. It would be useful if Ofgem could share its detailed model with all DNOs.

Definition of costs and incentives

We share Ofgem's concern regarding the current uncertain treatment of costs (particularly fault related) and support moves towards greater certainty.

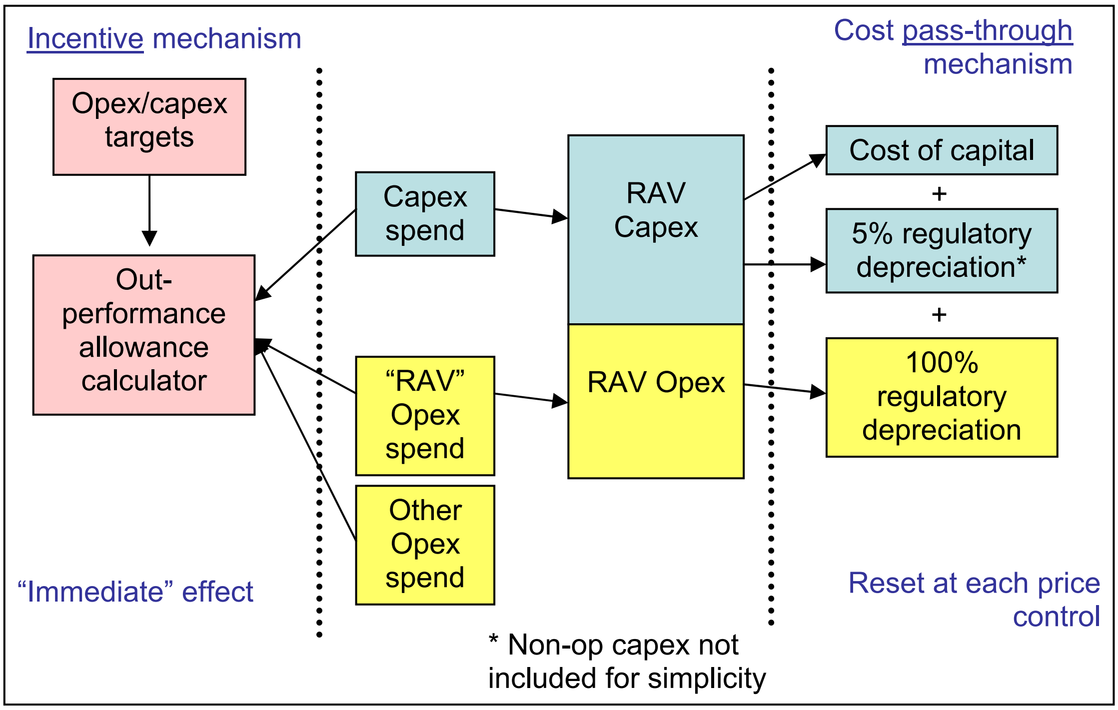
Ofgem's proposed approach would benefit from a worked example in order to fully understand its implications. However, in the absence of this, we make the following assumptions:

- Cost recovery and efficiency incentives are to be subject to separate mechanisms;
- Therefore the incentive rate (i.e. the cash rewards or penalties) does not need to be related to the quantum of regulatory depreciation or return;
- If so, this would imply retrospective cash adjustments each time the RAV is reset, including adjustments for efficient overspends;

[1] This is calculated by ((21+20)/2*0.065)/2

- The rate of regulatory depreciation is unaffected;
- Changes to allocations between cost categories within the RAV have no effect on incentives provided that the incentive rate is the same;
- Residual opex (i.e. not faults) would not be included in the RAV, but would be subject to separate incentive arrangements.

The arrangement can be shown pictorially as follows:



Assuming our understanding is correct, Ofgem's proposal has merit regarding the issues associated with the allocation of costs between capex and opex.

The question of the appropriate strength of incentives is, as noted above, a separate one subject to the constraint that "RAV" opex and capex incentives are of similar strength. The strength of incentives on non-RAV opex can be different as there is less risk of inappropriate allocation.

We note that Ofgem's proposal does not improve the quality of benchmarking and the setting of cost allowances. Robustly defined information returns would still be needed for this purpose, and we continue to support any initiative by Ofgem to achieve this.

Incentives for capex deferral

We support Ofgem's initiative to review the operation of the capex efficiency with a view to making improvements. We do not support any weakening of the incentive as we believe this will be counter to customers' interests (we explain below). Instead we propose an alternative approach.

We believe that the problem lies more in the linear form of the incentive rather than its strength. Currently, no matter how large the deferral, and departure from forecast, each £ deferred earns the DNO the same marginal reward. Reducing the strength of the reward, but keeping its linear qualities may well provide a stronger incentive to defer as companies struggle to meet shareholders' expectations on returns (which are driven by a combination of the cost of capital and outperformance growth assumptions).

A more satisfactory approach would be to maintain a strong incentive, but to apply collars and/or variable sharing factors beyond certain break points. In this way, underspends would be subject to weaker incentives, and so on. Similarly, overspends could attract a zero incentive rate for a certain percentage overspend, after which a disincentive rate could apply.

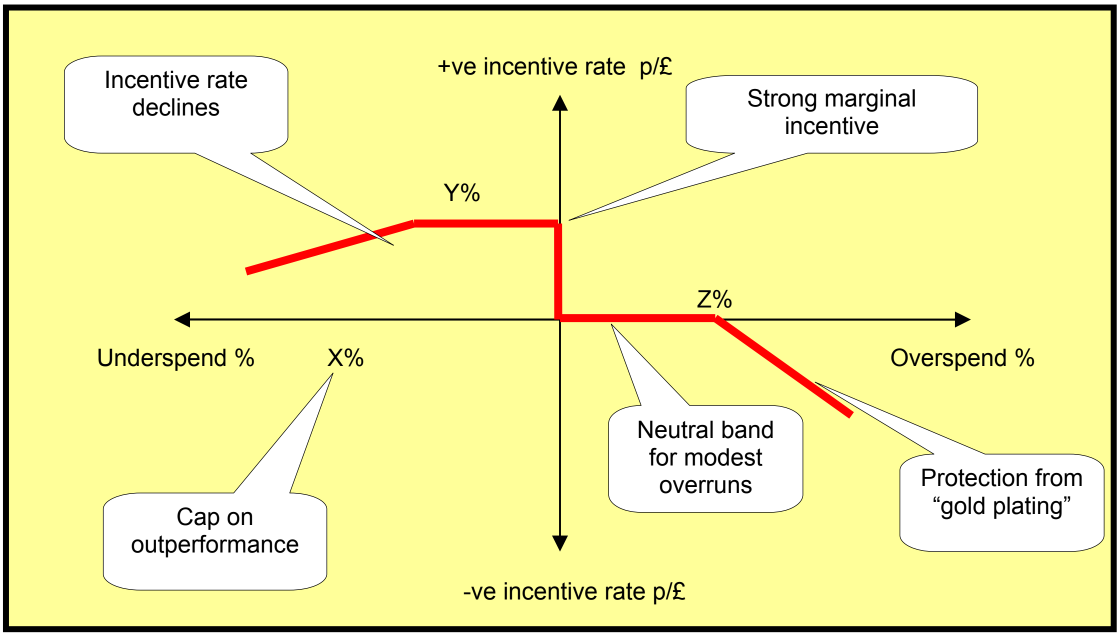
Clearly such a proposal would not remove the prospect of companies gaming targets altogether, but it would go a considerable way to dealing with such a risk. In addition, Ofgem will undoubtedly scrutinise and challenge companies' investment plans during reviews thereby providing a further safeguard to over-stated forecasts.

There are important reasons why a strong capex incentive should be preserved:

- It provides a downward pressure on unit costs; and
- It stimulates innovation and smart delivery solutions

both of which have delivered, and will continue to deliver, substantial long-term benefits to customers. Indeed, such incentives are the primary reason why EDF Energy's distribution charges are among the lowest.

Our proposals are shown pictorially below. Of course, this form of incentive is familiar to Ofgem's as it has similarities with the structure of SO incentives applied successfully to NGC.



Ofgem is known to be concerned about applying the same break-points to all companies irrespective of the relative size of their capex programmes. We find it difficult to reach this conclusion and would ask that Ofgem sets out its concerns for comment. We believe that the scope for genuine savings ought to be similar irrespective of programme size.

We do not believe that it is practicable to fully link capex incentives with output measures because of the long time-lag between deferral and performance impact. Indeed, particularly where networks are heavily loaded, it may be impracticable to undertake the work in time to prevent deterioration in performance. The UK railway industry's current predicament provides a clear example of the catch-up difficulties that extreme deferral can lead to.

Treatment of capex overspends

We support the need for clarity regarding the treatment of capex overspends, but consider it essential that such clarity is provided at the time of the relevant expenditure, and not only later as part of price control reviews. We agree that where there is clear evidence that spending has been wasteful and unnecessary, that such costs should not be added to the RAV. For clarity, we would not regard benchmarking as necessarily representing such "clear evidence" because of the degree of error that is inevitably involved.

Ofgem's remaining tests are a little confusing as it is hard to imagine a class of efficient spend that does not benefit customers. In the interests of clarity, and of predictable regulatory outcomes, we recommend that all overspends not "wasteful and unnecessary" should be treated alike (i.e. regulatory depreciation and return commencing from the year the expenditure was incurred). Ofgem should set out clear guidelines, in advance, regarding how it will apply its eligibility rules.

Our suggested capex incentive mechanism (above) could provide an alternative to Ofgem's proposed rule based approach.

Losses

In order for Ofgem to ensure that companies are appropriately incentivised to reduce losses, they must:

- Ensure that there is cost recovery for efficient expenditure, either opex or capex, to reduce losses; and
- Set an incentive rate which ensures that the losses incentive is balanced with other price control incentives, hence allowing companies to make efficient decisions

Therefore, we welcome the principle that efficient expenditure to reduce losses will be allowed in the RAV. However, it is currently unclear how the efficiency of such expenditure will be judged. The impact of any investment in low loss distribution equipment will take a significant period of time to become apparent in the reported figures. Consequently, there is a risk that the investment may not be judged efficient and hence cost recovery not ensured. Unless the efficiency tests are set out explicitly then it is likely that companies will be disincentivised from investing in low loss equipment. We also believe that companies should be allowed to recover the efficient costs associated with revenue protection activities. Theft of electricity is a key component of non-technical losses and consequently revenue protection activities play an important role in the efficient management of this aspect of losses.

It is vital that Ofgem clarifies its position on the incentive rate to be used in the new scheme. Based on our own analysis, if the same incentive rate is applied to each 1kW/h saving under the current and proposed schemes then the net present value of this saving is greater in the current mechanism. Therefore, for the proposed scheme to have al least the same incentive power as the current one the incentive rate must be increased above current levels. This leads to the conclusion that, for the new mechanism to provide a greater incentive than the current one does to reduce losses, the incentive rate would need to be increased substantially.

In addition, we continue to be concerned that Ofgem has asserted that settlements data volatility will reduce. Under the proposed mechanism if a change in settlement data occurs in the next price control period, which results in an increase in the reported losses, then the use of a fixed average will result in the company losing revenue for a circumstance outside its control. This must increase the risk that DNOs face and hence increase the cost of capital.

Based on the information presented the proposed rolling mechanism would appear appropriate. However, until the detailed algebra is available for review, including that associated with the newly defined LAF floor, we cannot comment fully on the proposals. We support Ofgem's proposal to consult on the transitional arrangements, as the change over between the incentive schemes may result in perverse outcomes.

However, we do not believe that the DNOs should be exposed to any of the losses that may arise from distributed generation. Such an approach may result in DNOs being disincentivised from connecting some generation. This would clearly be inappropriate.

Price control for metering services

EDF Energy has a unique perspective on the current and developing metering market for both MOp and MAP, as we employ three different service providers (two of which are independent of EDF Energy plc). These three service providers carry out MOp services over our three respective distribution service areas to fulfil our licence obligations. It is therefore difficult for us to imagine ourselves retaining bargaining power within a competitive meter market, as it will be these very service providers who are likely to be our principal competitors.

MOp

It is important to remember that it is our MOp service providers who ultimately have the 90-100% market share alluded to in Appendix 3. It is these service providers who are already able to offer, and are offering tailor made services to suppliers in and out of area. As suppliers are already in a position to make a choice, it is our view that the current competition law that applies to these service providers ought to be more than sufficient to govern any residual DNO MOp provision as well. We therefore see no need for residual service and price control obligations on DNOs.

If the obligation of 'last resort' remains in place then we would expect an allowance to be included with the distribution price control which would cover the historic and future fixed costs of this obligation taking account of the DNOs' reduced bargaining power. Where services are bought in under arm's length competitive tendering arrangements, DNOs should be allowed to recover the full cost.

If price controls are applied to MOp services, one approach would be to develop an average revenue cap derived from the number of visits. However, we would be concerned that time and the information (normalisation process) needed to develop robust numbers may not be available for this approach to be practicable.

We believe a more appropriate approach would be to have a functional definition in relation to a MOp price cap. Ofgem could specify a list of MOp services e.g. "a visit to replace a credit meter with a prepayment meter within H hour time window specified at least D days in advance" which could be capped while all other services or the same service with increased levels of delivery would be outside the scope of the price control.

MAP

If the Competitive Market Review and the RIA conclude that there is not sufficient competition in MAP then we would support, in principle, the idea of having price controls on DNOs for meter asset provider services. This would be limited to 'basic' domestic meters with non discrimination provisions for other MAP activities (paragraph 3.91). This approach would also be subject to a clear definition for 'basic' meters (paragraph 3.98). This would need to be based on specific engineering details (for example a "single rate meter certified for use in Great Britain under the relevant legislation which can measure the quantity of electricity supplied from a single rate supply".

A clear understanding of the type of price control mechanism is required. If the price cap takes the form of an explicit amount (based on historic meter costs, overhead and return) it may undermine future price negotiations between DNOs and manufacturers. We would prefer that a pricing formula be put in place that allows DNOs to make a reasonable return (capped).

The argument that, by having a basic price formula, customers will no longer be protected because of the perception that DNOs will not negotiate a low meter asset price, is misconceived as DNOs will negotiate the lowest cost possible to reduce the risk of losing MAP market share and to reduce the level of future stranded costs.

It is unreasonable and premature to suggest (paragraph 3.101) that companies should change their prepayment technology to one defined type as it is suppliers who will ultimately drive the meter asset market. It is suppliers who will decide on the type and functionality of meter assets that will meet their requirements in each DNO area. By predefining a particular type of asset for all DNOs, Ofgem may inadvertently be favouring a particular technology and so may stifle the prepayment meter asset market.

We are pleased that Ofgem aims to minimise the price controls on metering. However the focus should be on allowing DNOs to exit from the provision of metering services. It is unrealistic to think that DNOs will want to compete or even grow in a competitive metering market (current levels of outsourcing are evidence that this process has already commenced). This is due to suppliers looking to appoint national/multi-region service providers.

Quality of service and other outputs

Guaranteed and Overall Standards of Performance and Service (GSOPs)

We are pleased to note that Ofgem recognises that establishing full phase connectivity for automatic payments is not practical at present.

<u>‘Semi-automatic’ Payments</u>

A ‘semi-automatic’ mechanism, for an 18 hour restoration standard where specific customers are notified of their right to claim is operable in normal circumstances i.e. where small numbers of customers are affected for each incident. However, under severe weather conditions or other exceptional circumstances, this would not be practicable.

Whilst we accept that every effort should be made to compensate the customers affected, we should not be penalised where we are not able to contact the occupier of a property.

We are pleased to see that Ofgem recognises that GS2 could be amended to allow separate mechanisms for normal and severe weather. Given the complexity of potential circumstances and limited experience of the operation of the existing interim arrangements, we consider that the implementation of the severe weather mechanism should be in a licence condition rather than a Statutory Instrument to enable flexibility.

<u>Business customers</u>

We are pleased that Ofgem has recognised that we cannot differentiate our service to customers connected to the same low voltage networks.

Large commercial customers connected to the high voltage networks have the ability to choose the security of supply in their connection arrangements. In our opinion this is often the best expression of their willingness to pay for enhanced security. This must be considered when the results of Ofgem’s willingness to pay survey are reviewed.

<u>Overall Standards</u>

We continue to support Ofgem’s decision to remove the Overall Standards and replace them with reporting requirements within the Information and Incentives framework.

<u>Multiple Interruptions Standard</u>

We await Ofgem’s further thoughts and will be pleased to contribute.

Priority Service Customers

We support Ofgem in its efforts to improve the priority service process. Effective provision of enhanced service relies on the definition of a priority customer being appropriate.

Reviewing IIP

Disaggregated Data

We will be happy to provide Ofgem with this data. The disaggregation process developed by Ofgem has not yet been shown to be robust over time and we are happy to support Ofgem in establishing a more developed and robust view of quality of supply drivers.

Worst Served Customers

We note Ofgem's proposals for reporting customers who receive a number of interruptions per annum. A similar measure could be included to cover the number of customers who have received a number of interruptions over a five year period.

Connections

We support the proposal to remove the Overall Standards and replace them with reporting requirements.

Form of the Incentive Scheme

We continue to believe that rewards and penalties for quality of supply, namely number (CI) and duration (CML) of incidents should be symmetrical within the IIP scheme to allow the valuation of marginal improvements not funded through a specific quality of supply programme.

Rolling up financial rewards and penalties would smooth some of the risk of annual variability experienced by all DNOs, and we therefore feel that this merits further consideration.

The form of the incentive scheme must be consistent with the method of target setting and annual assessment and should also consider the other incentives on investment if it is to be an effective mechanism.

Weighting of Planned and Unplanned Interruptions

Whilst customers may value planned and unplanned interruptions differently, we consider that applying different weightings or values within the incentive framework is an unnecessary distortion.

We believe that there are two alternative approaches. These are:

- Make an appropriate allowance within quality of supply targets based on companies proposed investment programmes; or
- Exclude planned interruptions from the IIP scheme but monitor performance as part of the RIG.

Our preference would be for the latter.

Adjusting Data for Inaccuracy

We initially support a streamlined audit process with samples being based on relative CI/CML contributions and to consider moving to self audit once consistency has been established over time.

We support not making full adjustments only to those companies who fail to meet the accuracy requirements. However adjusting all DNOs' performance to 100% creates an unnecessary complication. We therefore propose that Ofgem considers adjusting companies who fail by the difference between the average DNO accuracy and their performance.

Target Setting

We would be happy to work with Ofgem in establishing an appropriate means of setting targets before their Initial Proposals paper in June. A number of approaches are possible and Ofgem should consider the results of more than one approach.

Any target mechanism must work within the form of the IIP incentive and in alignment with any QoS investment programmes. It should make allowance for some degree of annual variability, either through dead bands or the use of averages. However, dead-bands would have to be too large in comparison to potential improvements to offer much comfort against annual variability and we therefore consider that targets set using average performance over a number of years have greater potential, particularly when combined with rolling up penalties and rewards. This creates an incentive to improve annual and average performance.

For the scheme to act as an efficient investment driver, the consideration of the combination of incentive rates and targets is important. For example, if the penalty rate is greater than the reward rate, then companies may invest more to ensure that they do not fail their quality of supply targets. This is inefficient and not in customers' interests

Treatment of Planned Interruptions in the final year of this price control

We acknowledge Ofgem's offer to roll forward planned interruptions. We will advise Ofgem of our decision separately.

Frontier Performance

We welcome this initiative as it recognises the differences in the difficulty of targets within this price control period.

Network Resilience

We recognise as a significant step forward the separation of IIP and severe weather related incentives. Ofgem's proposals in the March paper advance these issues considerably.

Significant work remains in defining the boundaries of the suggested events such that improvements in performance, through reducing the impact of an event on customers, are not disincentivised. It may be better to define bands on exceptionality (the number of incidents) rather than its materiality (number of customers affected). We will work with Ofgem through the QoS working group to move this work forward for the June paper.

We believe that caps on a DNO's liabilities and the payments to individual customers are appropriate. In light of the limited experience of the interim arrangements, we do not believe that the limits should be changed for the next review period, i.e. they remain at 1% of price controlled revenue and £200 per customer.

Telephone Response

Whilst we support the decision to include customers who have calls answered by automated messages, issues remain with the provision of certain numbers by BT, who it appears cannot remove the CLI identifier for ex-directory or withheld numbers within their systems. We understand that Ofgem is also actively engaged with BT in identifying potential solutions. We would be happy to continue to work with Ofgem to determine the best way forward.

In developing the survey, Ofgem should ensure that comparison with previous surveys can be maintained. We believe that this can be achieved by introducing questions for a trial period before fully changing the questionnaire, as is being done with speed of response.

We continue to believe that Ofgem must carry out a regional factors assessment of customers' service level expectations in order for the published results of the survey to be meaningful.

Form of Telephone incentive

We continue to be of the opinion that an absolute scheme should be in place, with a common minimum level of performance, below which incentives apply. Good service levels already exist in the industry and Ofgem should not incentivise different levels of service in different parts of the country, nor levels of service that customers are unwilling to pay for.

Environmental Outputs

We support Ofgem’s collection of data on environmental performance similar to that carried out in the past by the Electricity Association.

With regard to the specific measures, we support those proposed but believe that the volume of oil lost must be put into the context of:

- The amount of pressurised oil cable in service; and
- The extent of company specific programmes (and Ofgem’s agreement to these) to manage oil leakage and replace problematic cables.

We note that the amount of cable kilometres in service is requested in the revised IIP RIGs.

General Discretionary Reward

We believe that such an arrangement would be too subjective, particularly if it is focused on those outputs not otherwise incentivised. We do not believe that there is any robust means for Ofgem to objectively assess performance comparisons between DNOs, particularly given the present low customer awareness of DNOs’ responsibilities and associated charges. A discretionary mechanism would therefore offer no incentive and so, in our view, would be poor regulatory practice.

Distributed generation, innovation funding and Registered Power Zones

Incentive framework for distributed generation

As has been mentioned in previous consultation responses, we have consistently supported the need for an appropriate mechanism to incentivise distributors in relation to the connection and operation of distributed generation (DG). We therefore welcome Ofgem's continuing commitment to such an approach and the increasing clarity of the details of the scheme. In particular we welcome, in principle, the introduction of protection from very high cost projects, the partial protection against stranding, and the floor and cap to the rate of return that DNOs obtain from their investment in connecting DG to networks.

However, we still consider that the scheme - in view of the serious and profound issues that climate change raises - lacks ambition and does not yet sufficiently encourage distribution network operators to invest in their networks to further prepare them ex ante for significant DG connections. A scheme designed to provide stronger incentives to distributors to facilitate DG connection through strategic investment would be more likely to lead to DNOs further intensifying their efforts to increase such connections.

The March paper has further clarified the details of the scheme. However there are still some matters that need to be resolved. The issues include the following:

- The level of return necessary to incentivise distributors to invest in preparing networks for DG ahead of the emergence of specific connection requests while avoiding stranded costs
- The treatment of large schemes
- The treatment of micro-generation
- The treatment of future non-project-specific strategic and overall DG related costs
- The linkage between the scheme and the current statutory framework for connections
- The suitability and practicality of the availability incentive.

These points are examined in more detail below.

Finally the regulatory impact assessment for distributed generation and the structure of generation charges concludes that the potential benefits of the proposed arrangements that would be realised, primarily by DG, but also those by all other parties, outweigh the costs (or negative impacts). Whilst we recognise that there are many uncertainties within this assessment we broadly agree with that conclusion.

Overall rates of return

We support Ofgem's preference for the 80% pass-through and the £1.50 per KW (before the O&M element) incentive rate option for the DG incentive scheme compared to the 70% option. This, together with the proposed protection from high cost schemes and the overall rate of return floor to the scheme over the next price control period, goes some way to addressing our previous concerns regarding the risks of the scheme. However we are not yet convinced that the skewed approach to risk-and-reward in the December paper has yet resulted in an acceptable outcome.

We have reviewed the available returns from the hybrid scheme as outlined in the March paper and have explored the potential returns based on a significant number of scenarios, including our original DG-BPQ submissions. The results indicate that there is a wide range of potential outcomes, in view of the uncertainty that surrounds the scale and speed of DG development and which technologies will initially emerge. For example, in the EPN area there is an appreciable likelihood that such returns could be anywhere within the range indicated by the floor and caps that Ofgem has suggested.

"Strategic" investments

We still consider that the scheme - in view of the serious and profound issues that climate change raises - lacks ambition and does not sufficiently encourage distribution network operators to invest in their networks to further prepare them for significant DG connections, and has not yet wholly eliminated the risk-and-reward imbalance that previously existed. We do not feel that Ofgem has sufficiently balanced the desire to avoid what they perceive to be inefficient expenditure with the scale and significance of the climate change issues that we are all addressing.

By strategic investment we mean investment ahead of realised generation connection applications even though there may be a reasonable likelihood of such applications if the distribution network in the area is strengthened. In our previous response we argued that it was important to recognise that any such investment will be competing with all other potential investments available to the providers of equity – therefore covering both regulated and unregulated businesses and a number of international markets – and so will need to have the potential to achieve a rate of return which is attractive in relation to such other investments, taking account of the risk profile. We continue to believe in the strength of these points and believe that refinements to the scheme, outlined in the paragraph below, would be beneficial in resolving them.

The refinements to the scheme outlined in the March paper are useful steps in improving its effectiveness and acceptability. However, we consider that some further refinements to the scheme would be beneficial. In particular, we believe that consideration should be given to increasing both the £1.50 incentive rate and the overall cap to the scheme to in excess of two times the allowed cost of capital. These changes would provide a suitable risk-and–reward balance and would increase the potential attractiveness of schemes where some initial investment will facilitate the emergence of DG schemes in a particular area. Without these changes, investment may be inhibited with a profound effect on the government's ability to meet its targets for renewable generation.

Micro-generation

We believe that the potential proposal to omit micro-generation from the scheme is incorrect and misunderstands likely market developments. Whilst it is usually true that the impact of individual micro-generation connections on the network is limited, there are several reasons why DNOs need to be incentivised and some cost recovery should be allowed:

- It is likely that micro-generators will, in a significant number of cases, be installed in clusters in both new and refurbished housing developments. This is likely to lead to a number of network design and operational issues arising. Efficient and effective network designs will be needed to address these and thus DNOs should be incentivised to identify such solutions.

- In addition the penetration of micro-generation will increasingly impact on business processes such as those needed to handle network faults where it will not be possible to assume that a network is dead when work is required to be done on it with consequential implications for work processes

- Cost savings from omitting micro-generation from the scheme will be minimal as most of this information will anyway need to be retained for network planning and other reasons.

Should micro-generation be excluded from the scheme it would be necessary to re-visit its overall design and calibration to establish the impact on the overall rate of return.

Future non-project specific strategic and overall DG-related costs

We also continue to be concerned about the treatment of future non-project-specific strategic and overall DG-related costs (as shown in Table 13 of the September submissions). Little attempt seems to have been made to take account of these costs in the DG regime that Ofgem is proposing and the associated cost recovery mechanisms for such costs are inadequate.
This may arise because the items that we included in this category are very varied and may not be easily treated as pass-through. They include both operating costs and capital expenditure, but do not cover cases where networks are being speculatively prepared for DG ahead of the emergence of specific connection requests. Examples of the higher costs are changed business processes to manage faults, more complex network control arrangements, switchgear replacement and reinforcement resulting from the incremental effects of DG, additional planning costs, and billing and registration costs arising from the introduction of generator use of system charges. It would be useful if Ofgem would clarify how it proposes to treat the recovery of such cost.

Legal aspects

We have, on several previous occasions, referred to the need to ensure that a hybrid incentive scheme is soundly based on the legal and regulatory structure for connection. This point has arisen from doubts about the relationship of such a scheme to section 19(1) of the Electricity Act – which permits distributors to recover their reasonable costs in respect of individual section 16A applications. So far Ofgem has not commented on this point. This should be done so that a clear legal foundation for the scheme can be established.

Connections for both demand and generation

Our previous response noted that many connections (notably those associated with CHP schemes) will be for both demand and DG purposes and the hybrid scheme will need to be specific on the allocation of capital expenditure between these two aspects. We therefore recognise the need for a specific reporting framework with definitions and guidance notes, although care must be taken to limit the burden that this could create.

Availability incentive

Ofgem is persisting with proposing an availability incentive. We can only repeat the points that we made in our previous response that whilst the desire to have such an arrangement is understandable, the existing proposals are not acceptable as there are many issues that continue not to have been addressed. These include:

- The relationship with other forms of "compensation", such as contractual liabilities, guaranteed service standards, and the IIP scheme, so that the overall impact of particular events can be assessed.

- The failure to provide a cost recovery or incentive mechanism. There needs to be the prospect of some upside or otherwise this will be a systemic risk that merely increases the cost of capital.

- The need to exempt existing schemes with weak connection arrangements from the scheme

Reporting burden

We are increasingly of the view that with the further complexity of the proposed scheme there will be a significant number of implementation issues that will need to be addressed. Many practical queries and questions are likely to arise. As previously noted we therefore recognise the need for a specific reporting framework with definitions and guidance notes although care must be taken to limit the burden that this could create. Clarity on Ofgem's intentions on how and when it sees these requirements being defined would be very helpful.

Use of annuity factor

We note Ofgem's apparent preference for the application of an annuity factor as the basis of calculating annual costs to be passed through into regulatory entitlement. However, whilst we agree that this is a practical approach we are concerned that the existence of two different approaches for the treatment of capital expenditure, according to whether it is treated as demand or generation driven, increases the possibility of distortions arising.

We are also concerned that the annuity approach will, compared to a RAV approach, will mean that generators pay off less of the cost in the earlier years and so are more exposed to the risk of stranding in later years. This would also increase the incentive on generators to close plants early to the extent that they avoid GDUoS charges in doing so. Ofgem has yet to decide the structure of GDUoS charges, but the use of annuity payments provides a strong reason to impose some kind of long-term payment obligation on the connected generator, to minimise stranded costs.

Innovation Funding Incentive (IFI)

In our response to the December paper we argued that the IFI, if properly structured, may be a very useful mechanism to encourage distributors to give greater emphasis to the development work required to bring about network transformation. This continues to be our view and thus we welcome Ofgem's intention to proceed with its implementation at the intensity rate of 0.5 %. We also welcome that the scope of IFI is as outlined in the December paper and thus covers a large part of the overall innovation process. The introduction of limited carry forward arrangements is also useful.

We also concur with the conclusions of Ofgem's regulatory impact assessment for its proposed policy relating to research, development and demonstration and believe that these provide considerable support for the implementation of the IFI.

Whilst we welcome the retention of the 90% pass-through proportion in the first year, reducing to 70% in the final year of the price control period, we are still of the view that there is a need to further increase the pass-through proportions. The reasons for this are as previously mentioned; firstly the mismatch between Ofgem's desire that the results from this investment in innovation should be rapidly shared among all distributors, and the share of the investment that they are themselves expected to contribute; secondly current distributor investment levels in innovation (as shown in Ofgem's paragraph 5.48) are low and there is a need to kick-start the process and thirdly there will be a need for a sustained period of investment in innovation if the future benefits are to be delivered.

Therefore, if the intention is that the results of such innovation should be shared and that the need for sustained investment at a significantly higher level is recognised, then we believe that the pass-through level should be maintained at the 100% level throughout the forthcoming price control period. This would provide a suitable kick-start to this process, the results of which could be assessed as part of the next following price control review.

We welcome Ofgem's recognition of the need to take account of distributors' own costs. The benefits of a good practice guide for the management of R&D projects seems very sensible although we are somewhat concerned that the production of a single guide for the whole sector via the DGCG and the TSG could be time consuming. We would hope that even if such a process were being followed that interim arrangements could be used, especially if some IFI projects start before the next price control period. Additionally it would be helpful to understand how Ofgem sees the cost recovery mechanism for projects started in this price control period operating.

Registered Power Zones (RPZs)

We continue to be broadly supportive of the RPZ concept and again feel that the conclusions of Ofgem's regulatory impact assessment for its proposed policy relating to research, development and demonstration provide support for the implementation of RPZs. However, we share Ofgem's view that further work with affected parties is required to ensure effective implementation.

Perhaps the production of the registration guidelines that are referred to in this paper would be a useful mechanism to clarify both the issues with RPZs and how they will be resolved. It is to be hoped tha this would lead to the emergence of a regime that is relatively simple to understand, can be cost effectively run, and provides sufficient incentive to distributors to develop, bring forward, and implement suitable demonstration projects. The potential for derogation from certain industry codes, standards and engineering recommendations in appropriate circumstances may well be a useful approach to increasing the attractiveness to a DNO of moving forward with an RPZ.

In our previous responses we have expressed concerns about the attractiveness of the RPZ scheme in view of the risk-and-reward balance within it. We note Ofgem's assertion that the risks associated with RPZ projects are covered by the potential to earning higher rates of return. Whilst recognising this point we are not yet convinced that a balance has been achieved that will ensure that DNOs are sufficiently incentivised to bring forward such projects. For example in our previous response we argued that RPZ projects are, by definition, going to be leading-edge projects and therefore subject to significant technology risk. In addition, Ofgem's previous consultation paper indicated that in most cases the distributor would be expected to shoulder the exposure to potential IIP and guaranteed service penalties. There is therefore a significant likelihood that, however well managed, the costs could exceed those expected. We feel that there is a risk that the level of incentive may not be sufficient to prompt action. As we have previously argued, an incentive which is entirely based on the capacity of DG connected may well be weak if it is likely to be preferable to initially trial innovative solutions on a small-scale before seeking to extend their size and scope.

In our previous response we also noted that the RPZ concept is based on innovation focused on DG. We stated that it was our view that this should be extended as soon as possible so that it also covers the large-scale trials that will be needed to take forward the innovative ideas emerging from the IFI process – whether associated with DG or not. This continues to be our view.

Assessing costs

Both the companies and Ofgem have experienced considerable difficulty in providing cost information that is comparable between DNOs. The root of these difficulties, in our view, lies in the use of regulatory accounting statements as the basis for price control information. Combining regulatory requirements with those of published financial statements introduces difficult conflicts between the information needs of the regulator and those of shareholders and other investors.

Differences regarding capitalisation polices have been a particular problem area. We believe that, for regulators, the allocation of costs between capex and opex is essentially a question of funding, and in particular the speed of cash generation from customers. However, a company's funding requirements can be determined independently of its capitalisation policies (as has already been the case where Ofgem accelerates regulatory depreciation for example), suggesting the primary purpose of cost information is the setting of robust cost allowances.

The lack of clear and understood activity boundary definitions currently makes many inter-company comparisons unreliable. Given that Ofgem relies heavily on such comparisons it must ensure that companies report activity cost data, including overheads, in an unambiguous way. EDF Energy would support such work to define and refine regulatory cost (and other data) templates, but believes that these will take some time and effort by all involved to secure consistency and also to prove the robustness of the result. However, the effort will be worthwhile because the regulatory risk inherent in the current arrangements is significant in our view.

Cost allowances must be robust and sustainable, otherwise DNOs will not be able to meet the requirements on them and deliver the appropriate level of service to customers. The least cost approach is often not the most efficient, particularly in the medium to longer term. Indeed, we would assert that Ofgem's duty to protect customers' interests means that it must satisfy itself (and others) that cost allowances are sustainable. In these respects, allowances derived from average costs pose less risk than those based on "frontier" companies.

Robustness of normalisation adjustments

As Ofgem has acknowledged, the process of "normalising" DNOs' costs has proved difficult. Whilst each company has contributed to Ofgem's work it is not possible for us to know whether the adjustments we have proposed are made on the same basis as those proposed by other companies. As a result we are unable to determine whether these adjustments are robust or not. We would therefore ask that Ofgem provides corroborative evidence.

We would expect Ofgem to use a range of techniques to understand whether the results of its modelling are robust and sustainable. Indeed, Ofgem has already said that it would do this. In our discussions with Ofgem, we have suggested that Ofgem builds up such a view using the flowing procedure:

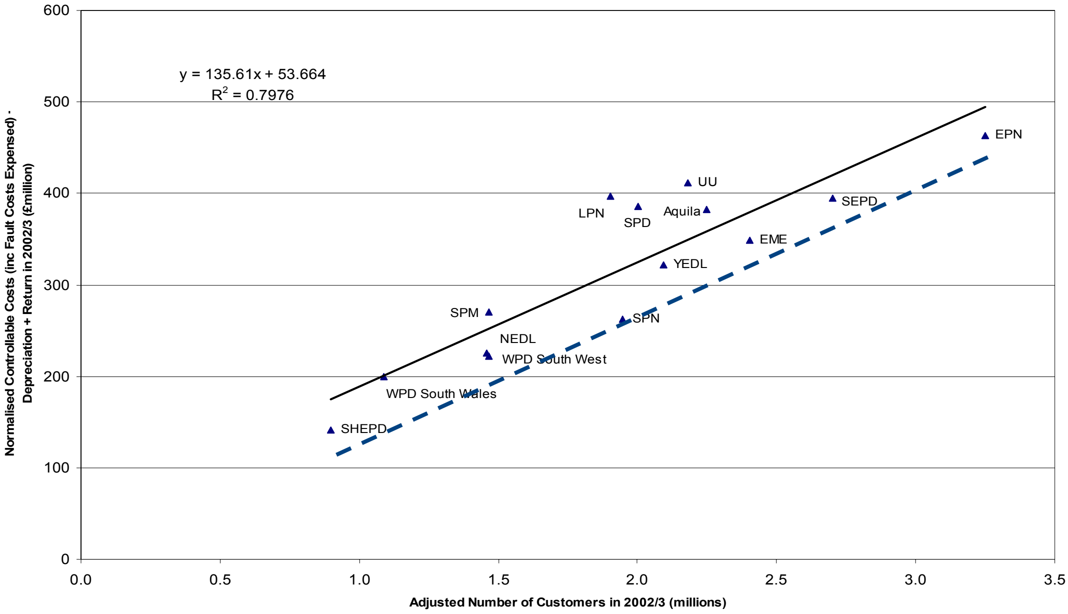
- Identify the main cost components; such as faults, maintenance, tree cutting, etc…
- Establish a sensible range for each component by removing the outliers (a recognised statistical approach)
- Apply a high level adjustment for overheads
- Compare the resulting ranges with modelled costs and investigate anomalies

Total cost modelling can also be used as a sense check, particularly regarding Ofgem's views of relative efficiency. Such models help to reveal residual differences in capitalisation, as well as the entirely legitimate effect of past opex/capex trade-off decisions (for example the choice between repairing faults (opex) and renewing/refurbishing lines (capex)). To ignore such trade-offs, as Ofgem currently appears minded to do, is not supportable.

An example total cost model example

We present below a view of 2002/03 cost levels on a total cost basis. It has been built up using asset book values at privatisation, adjusted for spend since then and a common set of depreciation rules. In this way RAV revaluations and differences in regulatory depreciation are ignored. Of course, a superior approach to total cost modelling would be to develop MEA values from asset registers; however, such data is not available.

Our total cost model is presented below:



Presenting costs on a total cost basis yields markedly different results from opex only, or opex plus faults models. In particular, different frontier companies emerge, indicating that opex or opex/faults only frontier companies have made different opex/capex trade-offs in the past. Assuming that a range of efficient trade-offs is possible, it would be wrong to assert that a particular company was inefficient based on opex or opex/faults only.

Degree of error/unexplained variables

Ofgem is attempting to explain costs using a combination of customer numbers, units distributed and circuit length. As such, regression models merely reveal the extent to which cost variations between DNOs are explained by these factors. It is not possible to tell whether such variations are as a result of relative efficiency, or because of other unexplained factors -for example, differences in opex/fault costs caused by:

- Past legitimate opex/capex trade-offs
- Regional costs
- Circuit design
- Vegetation coverage
- Urban congestion
- Ground conditions
- Circuit loadings
- And so on…

Ofgem has also changed the weightings used to derive the composite customer variable used in the last review, which has a significant affect on the allowances derived. Ofgem should explain its rationale for making such changes and present evidence that the results are robust.

There will also be unexplained inter-temporal differences. It is possible for companies to legitimately take cost-holidays from time to time, for example by delaying expenditure on maintenance, vegetation management, and fault backlogs (making permanent repairs).

Regional costs

EDF Energy has submitted a detailed report to Ofgem regarding the additional costs we face from working in South East England. To date, Ofgem only appears to have recognised the issue in respect of salary costs in LPN. Ofgem has not made any counter arguments against the other matters contained in our report, but appears to have chosen to simply ignore them. This is unacceptable. We believe that Ofgem must formally respond to the evidence we have presented. This is vital to ensure the transparency of the price control process.

Merger benefits

Any assessment of costs will need to take account of the legitimate expectations regarding the retention for five years of net merger benefits. This need not take the form of adjustments to benchmarking models, but can be accommodated in setting allowance glide-paths. Such treatment would ensure equity of merger treatment irrespective of when in the price control cycle the merger took place. We look forward to seeing Ofgem's further thinking in its June proposals paper.

Financial issues

Financial ring-fence

EDF Energy supports the cash lock-up mechanism as described, but believes that a formal mechanism for dealing with unforeseen costs (of the kind described in the recent paper prepared by ENA for Ofgem) should be introduced at the same time. This would ensure that the impact of unforeseen cost shocks could be addressed without recourse to more extreme cash lock-up or statutory energy administration arrangements.

The cost of capital

Ofgem has used the Capital Asset Pricing Model (CAPM) as the basis of its initial estimate of the cost of capital and in doing so has provided much significant evidence.

We have asked NERA to examine this evidence and to comment on Ofgem's use of it. NERA's report is attached to this paper. NERA finds that there are a number of inconsistencies between the evidence presented and the conclusions drawn by Ofgem. NERA has attempted to eliminate these inconsistencies and in doing so arrives at a cost of capital range consistent with its estimate set out in its March 2004 report for EDF Energy.

We ask that Ofgem respond to each of the points made by NERA.

Treatment of pension costs

<u>Allocation of liabilities</u>

We would like to re-iterate the points made in EDF Energy's response to Ofgem's December 2003 consultation document, which we believe are still valid. In particular, the cost of pension obligations, caused by past employees in formally bundled activities, derives from statutory obligations that companies cannot reduce or avoid. These obligations could not have been transferred without incurring cost to any competitive business unbundled from distribution, since such a business would not be able to recover such costs in a competitive market.

Notwithstanding EDF Energy's overall position stated above, we have various comments on Ofgem's proposals to allocate liabilities between price-controlled and non-price-controlled activities. Since privatisation, there has been a substantial decrease in the number of employees in price-controlled activities. Those staying with the company were redeployed into non-price-controlled areas. Conversely, there has been very little movement of people from non-price-controlled to price-controlled areas. As a result, Ofgem's proposal to assign liabilities based on current employment or last employment is inherently tilted against the regulated business. Employees' previous service in price-controlled activities should not be ignored if information on service history is available.

For scheme members who left prior to privatisation, we seek clarification from Ofgem of how it proposes to split liabilities in the year of privatisation. The prospectus document does not contain the necessary split of employment cost information.

Allocation of assets

On actuarial advice, EDF Energy supports a simple pro-rata approach to allocate assets rather than matching liabilities to various types of assets. Matching assets to maturity profiles is difficult to apply in practice. In addition, we believe that a complex approach to splitting assets would be inconsistent with Ofgem's simplifying proposals to split liabilities between price-controlled and non-price-controlled activities.

Over or under provision

Allowances in past price controls

We welcome Ofgem's acceptance that there have not been explicit allowances for pension costs at previous DNO price controls, and that it is therefore difficult to assess what allowances were previously made.

We are still of the view that the only objective and sound regulatory assumption that Ofgem can make is that previous price controls made allowance for all the contributions actually made, since logically it seems that this is the approach most likely to reflect the contribution that companies would have assumed they would be allowed at the time.

ERDCs

Ofgem seeks evidence of an agreement that consumers would bear the costs of funding ERDCs (irrespective of the timing).

Ofgem would appear to be implicitly assuming that companies (and not customers) bear the risks associated with outperformance decisions, including both those foreseen and unforeseen, in return for the possibility of earning returns above the regulatory cost of capital (which already remunerates risk anticipated by the financial markets).

However, where a company has incurred ERDCs in respect of cost savings purely to achieve Ofgem's ex ante prediction of efficiency savings (i.e. to keep up with cost glide paths) there is no prospect of an outperformance gain to fund the costs of achieving the required efficiency savings, nor is there any prospect of above normal returns to remunerate the associated risks. In these circumstances the costs of ERDCs must be borne not by shareholders, but by customers.

Furthermore, responding to price control pressures for efficiency gains, DNOs provided early retirement to many employees in previous regulatory periods.

ERDCs represent part of the cost of making such redundancies quickly. Because pension funds were in surplus at the time of the redundancy programmes, shareholders were relatively indifferent to the decision about whether to fund ERDCs out of surpluses or pension contributions. DNOs have used surpluses for pension holidays, benefit improvements and ERDCs to varying degrees. At the time, all of these decisions were considered rational and were endorsed by the pension funds' independent Trustees, who would have been conscious of general Inland Revenue pressures to reduce pension fund surpluses and in any event were required to eliminate scheme surpluses in excess of the calculated statutory level. Consequently, Ofgem's proposed treatment of ERDCs compared to other uses of surpluses would seem to be arbitrary and unfairly penalises DNOs who were making rational decisions at the time regarding ERDCs.

The restructurings occurring as a result of the redundancy programmes produced large reductions in the workforce and associated salary costs. At the time of the (past) decision to use pension surpluses for ERDCs, all reasonable opinion suggested that the funds were in surplus on an ongoing basis. Customers benefited immediately from this because they avoided the need to finance the costs of early retirement pensions. DNOs could not have reasonably known at the time that pension funds would go into deficit and therefore require increased contributions as a result. Any ex post review of DNOs' decisions must take into account only information that was available at the time, not information which became available only later.

Moreover, at the time that the current price control was being set, Ofgem would have been well aware from the publicity surrounding the lengthy litigation in the *Laws* case of the industry's widespread use of pensions surpluses to fund ERDCs.

Consequently, subsequent information that higher contributions are required provides no justification for Ofgem to re-assess the decision of DNOs to incur ERDCs out of the pension surpluses.

Ofgem acknowledges that these early retirement costs have not been recovered, and also that consumers have benefited from the early retirement programmes. But it now proposes to exclude them from allowed costs going forward, on the basis that there was no agreement that such costs would be recoverable from consumers. This position is indefensible on two counts. First, since Ofgem did not announce at the time that such costs would (or might) not be recoverable, companies will have taken decisions about ERDCs and the use of surplus on the basis of a rational expectation about Ofgem's future actions, consistent with the principles of good regulatory practice.

Secondly, to demand that DNOs produce evidence of an agreement to allow recovery of these costs puts them under an impossible burden of proof. As Ofgem is well aware, there is no evidence of agreement to pass through any category of cost under a future price control. Ofgem has not said why a requirement for such evidence should apply to these costs alone, or how the distributors should fulfil such a requirement. Ofgem did not tell distributors to collect proof of agreement in relation to ERDCs at the time, nor does it now say how they could have collected such proof.

In summary it is our view that, by the principles of sound regulation, DNOs are entitled to recover all the costs associated with their past ERDC decisions, including the increase in pension contributions that is now required. Any treatment of these costs that does not properly reflect this entitlement would effectively penalise efficient decisions, and so discourage similar decisions in future.

Allowances in future price controls

Ofgem's proposal is to apply over/under funding adjustments for all future price controls. If this is the case, we would expect Ofgem to record the allowance explicitly, to avoid harmful retrospective guesswork in the future. We also re-iterate our view (made in our response to Ofgem's December 2003 consultation document) that pension costs are no different from any other kind of opex and Ofgem should therefore explain why pension costs warrant special treatment. Adjusting future allowances for opex in the light of differences between past allowances and actual costs will damage incentives to cost reduction.

A more sensible approach might be to subject the initial allowance within the price control when it is being set to the uncertainty mechanism described in the recent paper prepared for Ofgem by ENA, since this is a cost which could move significantly during the period of the control but over which there may still be considerable uncertainty when the price control is finalised.