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22nd April 2004

Dear David

DISTRIBUTION PRICE CONTROL REVIEW – POLICY DOCUMENT

Thank you for spending time with us last Wednesday discussing issues arising from the Price Control Review. We mentioned our intention to submit an early response on the main paper, published on 24th March. This way we hope to accelerate the process for discussion of the issues raised, and have been talking to Martin about an early meeting to review our comments. We also expect to devote more attention to the supplementary documents, and will therefore make a further response around your deadline date of 5th May.

We raised with you one area of difficulty in preparing our response. This concerns the lack of a clear policy framework within which to gauge your detailed proposals. Within United Utilities we are particularly struck by the difference between the position in the water review (where the higher level policy objectives are clarified by debate between Ofwat and the environmental regulators) and in electricity, where the outputs and outcomes remain unclear.

This can be seen in the diversity in the FBPQ submissions from DNOs summarised in your document. It may be that companies feel very different levels of expenditure are necessary to meet the same objectives. On the other hand it is also possible that the underlying assumptions cause much of the variation. Whilst we recognise that there is no equivalent of the guidance on environmental investment in water, it is still valid to try to establish more clearly the direction the electricity industry should be taking.

We can see evidence of Government thinking in the Energy White Paper, but this does not lead to explicit proposals in terms of deliverables. There are areas where DNOs might be expected to make a significant contribution. For example the Trade and Industry Committee makes specific recommendations on future investment levels to support network resilience and contribute to security of supply. There are also targets for the development of CHP and renewable generation that need DNO support.

The main area of innovation in your consultation paper is the development of thinking on incentives. However it is difficult to evaluate these proposals without a view of the broader strategic framework within which they would operate. The key question is therefore: what should the incentives encourage companies to achieve? Only then can the suitability of any package of incentives be tested. This is an approach that we have advocated for some time, going back to the Information and Incentives Project. We have also discussed before, the extent to which Ofgem is dependent on more explicit guidance from Government.

In the absence of any alternative, it may be worthwhile for me to set out the key assumptions that have underpinned our work on the Business Plan questionnaires and provide the background to our response to your consultation.

Electricity distribution is a vital part of the energy supply chain, but is relatively inexpensive. The average domestic customer pays around £1 per week for this service. Network performance is generally good and we do not detect any strong pressure from customers for further improvements. However, we can see reasons to begin to increase investment expenditure to prevent an increase in fault rates, and to provide support for distributed generation in line with the move to a low carbon future. In both cases, it is reasonable for customers to see evidence of the success of companies, and we therefore accept the need for continued performance monitoring.

This simple characterisation of the delivery requirements consistent with the policy set out in the Energy White Paper must be balanced by a continuing need to provide our services efficiently. We believe that the growing importance of investment must be recognised in Ofgem's incentive regime, not through reduced incentives to be efficient, but through stronger incentives to deliver the desired performance. It would be wrong to weaken the incentives on efficiency at the very time that expenditure was expected to increase.

The attached paper provides a more detailed response to the issues raised in your consultation. It sets out our suggestions for improving the balance of incentives and for overcoming some of the reporting inadequacies that have increased Ofgem's concerns. It does not challenge any strategic vision that may be behind your proposals. It would be extremely helpful, and may save us both from substantial wasted effort, if you could identify whether, and if so where, our view of objectives may differ from Ofgem's.

I look forward to a more detailed discussion on the issues raised.

Yours sincerely

Lorna J Godby
signed on behalf of Mike Boxall
United Utilities plc

Mike Boxall
Head of Electricity Regulation

United Utilities Electricity PLC
Consultation Response

Electricity Distribution Price Control Review

Response to Ofgem Consultation:

March Policy Document

April 2004

Contents

1 Executive Summary

Ofgem's March consultation provides a final opportunity to comment on the approach they intend to use in formulating initial proposals for price controls for 2005-2010. It is therefore a very helpful progress report on the review. In summary our comments are as follows:

1.1 Timetable and Process

We are pleased with the more open nature of the interaction between Ofgem and DNOs but are becoming concerned that interim milestones for major projects (such as cost assessment) are not visible to us, and that substantial changes of approach (such as a reassessment of incentive structures) are being considered late in the process. It is also becoming apparent that the delayed schedule for specifying service outputs and outcomes is inhibiting discussion in other areas.

1.2 Form, structure and scope of the control

There has been useful progress in a number of areas, but we have been surprised to see some radical proposals for changes to the framework for incentives. Whilst we understand the concerns that have prompted this response from Ofgem, we do not think it is appropriate to weaken all incentives as a result. We would prefer to see a strengthening of the incentives to deliver, which can then back up a continuing emphasis on efficiency.

1.3 Quality of supply

There is evidence of significant progress on the framework for regulating quality of supply but the critical issue of future levels of service remains to be discussed. There is a worrying imbalance with cost projections being made, apparently independent of any progress on future customer service standards. We support the general direction of work on the form of incentives, although we are concerned that the definition of 'exceptional events' may discourage companies from investing to improve resilience.

1.4 Distributed Generation

We accept that Ofgem have worked hard to develop a price control regime that can offer powerful incentives to companies to meet connection requests efficiently. We do not believe these mechanisms will support the kinds of strategic investment that might have accelerated the progress towards a low carbon future. The additional incentives implied by the IFI and RPZ whilst not substantial financially, will assist the development process.

1.5 Assessing costs

This is the most critical area of the price review programme. It will lead to the determinants of much of our allowed revenue, but we do not yet have clarity of the process to be followed. More worryingly, the basic data analysis is still confused by the inconsistencies that remain in information obtained from the HBPQ. We have suggested a series of steps which Ofgem should take to make sensible use of comparative efficiency analysis in informing the calculation of allowed revenue.

1.6 Financial issues

It is helpful to see Ofgem's first thoughts on Cost of Capital. However these currently fall well below our own expectations based on discussions with investors in United Utilities. It will be important to find ways of bridging the gap, since continued access to investment funds will be essential if we are to fulfil the plans submitted to you in January.

2 Timetable and Consultation Process

We welcome Ofgem's continuing commitment to transparency and consultation, and appreciate the additional detail now provided with the outline timetable.

Whilst we agree that the published milestones for the period January to March 2004 were all achieved, we are concerned that there is no public visibility of interim milestones for the major activities that will feed into the June proposals.

We would be more reassured if progress in areas such as data normalisation, assessment of future revenue requirements, and development of financial models were reported to be on schedule. These are substantial tasks where we would expect internal project plans to identify checkpoints on the road to final delivery, which would add comfort that progress is on track.

In all these areas, there has been lively debate on the approach to be followed, and there has been evidence of significant work within Ofgem. What is not clear is whether that work is leading to a convergence of thinking on the way forward.

3 Form, Structure and Scope of Price Control

3.1 Introduction

We support Ofgem's objectives of:

- Maintaining an appropriate balance between incentives to deliver and incentives for efficiency;
- Relying on RPI-X as the foundation of the Price Control; and
- Avoiding distortion in the creation of a more complex structure of incentives.

Where we have concerns over the proposals in the consultation paper, they can be linked back to the extent to which the proposals do not achieve these objectives.

3.2 Form and Structure of the Price Controls

3.2.1 Revenue drivers

The structure of the current price control was a consequence of pragmatic decisions taken ten years ago to reduce the incentive on distribution businesses to promote energy consumption. The 50/50 split between customer numbers and kWh was never intended to be an accurate portrayal of cost drivers. It has, however, proved to be a reasonably robust form of revenue driver, and we support Ofgem's proposal to continue with this. We further support the additional steps proposed:

- To use actual customer numbers; and
- To review the weights applied to the voltage categories.

Both of these provide the opportunity to better match future revenue to costs, without undue additional complexity.

There is one proviso to our comments above: the proposal to add EHV income to the definition of revenue would tilt the balance substantially towards capacity as the driver. It is not clear that either customer numbers or kWh are an adequate proxy, and this would require further thought if the proposal to price control EHV sales is retained. We assume the 50/50 split would apply before any adjustments were made to incorporate EHV.

3.2.2 Price index

The indexation used in the price control should be both understandable for customers, and relevant for companies. We believe the long established RPI represents a reasonable compromise. Whilst HICP may be the Treasury's preferred measure it will be some time before the general public has grasped its significance. Ofwat has confirmed that it will be using RPI in the current water price review. Furthermore, the definition of HICP will add new complexity and may not be a reliable guide to inflation in any one EU member state.

From the companies' perspective, what matters is the likely movement in their own costs. FBPQ submissions have been made against inflation planning assumptions set out (by Ofgem) in terms of RPI. To use a different index in the price control would require a review of FBPQ estimates. This is an unnecessary step and could increase the risk to companies, with no obvious benefit for customers.

3.3 The Scope of the Price Controls

3.3.1 Transmission exit charges

We welcome confirmation of the continuation of the current price control treatment of transmission charges.

3.3.2 Treatment of wheeled units

We support the conclusions on wheeled units, although as with the proposal on EHV sales, it may be necessary to review the balance of revenue drivers.

3.3.3 EHV charges

We are very disappointed that the arguments against the inclusion of EHV charges within price-controlled revenue have been given so little consideration by Ofgem. We expect the issues to re-emerge as the detailed work begins on extending the scope of the control.

We have around 30 EHV connected customers, who combine to account for some £5m per annum of DUoS revenue. It is essential that any extended price control adequately protects us against the risk that costs and revenue do not move in line with each other. We fear that a formal price cap is less likely to achieve this than any of the other options set out in your December consultation.

3.3.4 Non-contestable connection charges

We have been supportive of Ofgem's policy of extending the scope of competition in connections. However, we believe that success should be established within the current plans in respect of connection assets, before trying to move further in introducing competition in the construction of network reinforcements.

We support your proposals to clarify performance in respect of non-contestable services. This should include the publication of relevant charges and the reporting of quality of service measures.

3.3.5 Other excluded services

We agree with the proposal to maintain the list of other excluded services and agree, subject to the proposed revenue driver, that units distributed to embedded networks should be treated as wheeled units.

We have always argued that all distributors should be treated consistently and therefore believe that a DNO operating out of area should face the same regulation of its income as any other licensed distributor operating in the same area.

3.4 Business Rates

We are already engaged in discussions with the Valuations Office Agency with the intention of minimising the rateable values on which Business Rates will apply. However we can see that it will not be possible to 'finalise' these numbers within the price control review timescales. The opportunity to appeal will only exist from 1 April 2005. There is an inevitable circularity in the methodology assumed by the VOA, since rateable values depend on future income, which in turn depends in part on estimated rates. We hope that dialogue between Ofgem and the VOA can establish an approach that protects customers and companies from unnecessary risk in this area.

3.5 Hydro-Benefit

We have no comments.

3.6 Dealing with Uncertainty, new Obligations and Costs

The initial work by the Dealing with Uncertainty Working Group encouraged us to expect a more robust approach to uncertainty than in previous reviews. This good start is still to be built upon, however, we do believe it is possible to identify mechanisms for dealing with most of the key areas of uncertainty. This could ensure that companies have some protection from movements in costs, while customers retain the confidence that companies have incentives to manage those costs wherever possible. The recent paper from the ENA provides a framework around which to build a detailed solution.

It is also appropriate to raise here unfinished business on cost shocks in the current price control period. We are still waiting to see the return of the bad debts incurred with the demise of Enron and Maverick Energy. It is important that these adjustments are made explicit in any price control calculations, and that arrangements are made to make any repetition more automatic.

3.7 Duration of the Price Control

We welcome confirmation of the duration of the next control. However, this need not constrain the retention periods used in other incentives. As Frontier Economics' earlier work identified, it is possible to use changes in retention periods to balance incentives between different classes of expenditure. In some circumstances, this may be more appropriate than increasing incentive rates.

3.8 Incentive Framework

We recognise the importance of a high level view of the incentive framework. Ofgem appear to have concluded that the power of incentives should be weakened. This is a surprising conclusion at a time when there is increasing public focus on the need for delivery of investment to preserve security of supply, and of investment to support the anticipated growth in distributed generation.

As we understand Ofgem's position it is that it is too difficult or too complex to measure outputs accurately and that it would be inappropriate to preserve powerful efficiency incentives without powerful counter-balancing output incentives. We understand the need for balance but do not accept that it is impossible to maintain a focus on delivery.

In our view the current incentive framework needs to be modified to provide stronger incentives to deliver. This need be no more than more transparent eligibility criteria to qualify for the payment of rewards under the efficiency incentives. In particular we would propose the introduction of high-level investment activity reporting, the development of a measure of network resilience to be reported annually, and the strengthening of IIP incentives.

Having made these changes it would be appropriate to maintain (or increase) the incentives on efficiency. At a time when investment needs to be increased, it would be wrong to weaken the incentives to invest efficiently. Customers will continue to want investment funds to be used wisely, and this includes encouraging companies to seek out more effective ways of delivering the goals of their investment programmes.

The current proposals imply that the cost of capital is in itself an incentive to invest. This is a dangerous assumption to make, since there will always be competing uses for investment funds. The dilution of other incentives will alter the balance of risk, since the downside (of failure to deliver) will still be in place, with a reduced upside from the weakened incentive regime. This may provide a more forceful argument for an increase in the allowed cost of capital than the exchange of academic papers on historical capital market performance.

3.9 Retention Period for Efficiency Savings

We are pleased to see detailed proposals for the five-year fixed period retention of opex and capex benefits. Our comments on the specific mechanics have been provided in previous representations and our responses to the draft financial models.

3.10 Definition of Costs and Incentives

There is no doubt that both Ofgem and DNOs have committed substantial resources to the efforts to adjust reported performance to achieve consistent definitions of opex and capex. However the problem appears to have been more a consequence of the lack of clarity and potential inconsistency of the previous price control settlement, than a sign of any inherent problem with definitions. What is needed is a very clear description of the classification of activities for regulatory reporting purposes. We do not believe this is an insurmountable problem, and should not be used to drive changes to the incentive regime.

However, some changes may be appropriate. In particular, we have sympathy with the proposal to treat types of costs which are substitutes in a consistent fashion, and we support the treatment of non-operational capital as a category of capex rather than opex. If it is necessary in order to increase confidence in the reported data from companies, we would support the use of external review, equivalent to the role of Reporter in the water industry.

3.11 Incentives for Investment Deferral

As with the previous issue, we recognise the problem that Ofgem have identified, but do not believe the remedy is the most appropriate. If there is a problem, it is that no formal reporting of investment deliverables exists. Consequently, any ‘under-spend’ against price control allowances raises suspicions of under-performance.

A reduction in incentives will reduce innovation by companies in identifying more efficient ways of delivering outputs and also innovation in developing capital proposals for reducing opex. Reduced incentives will result in fewer projects passing our approvals process hurdles.

The price control review process has challenged the reporting of investment performance and required companies to identify the sources of capital efficiencies. This has allowed a distinction to be drawn between doing less work and delivering outputs at lower cost. What is needed is a regular form of reporting that fulfils this purpose. We understand Ofgem’s reluctance to micro-manage the DNOs. A reasonable compromise may be to have project by project reporting only for the major Grid and Primary investments, with higher level volume counts for work on other voltage levels. The intention should be to provide a level of comfort, without removing the incentives to innovate in the development of appropriate solutions.

The second element of reporting should be a renewed attempt to monitor network capability. We have made suggestions for the basis of a resilience monitoring framework, which could be developed in the months ahead to provide a further check that investment was not being deferred to the detriment of customer service. Furthermore the IIP could, if necessary, be strengthened to add more power to the incentives to deliver.

3.12 Treatment of Capex Over-spends

We agree that wasteful and unnecessary spending should not enter the RAB. We would like to see the criteria to be used to determine whether additional investment was deemed to provide significant customer benefits, before accepting any sub-division of ‘necessary spending’.

3.13 Losses

We have tried to play a constructive part in the discussions on incentives on losses, and we recognise the difficulty of the task. We continue to support the intention of creating a genuine incentive for DNOs to reduce the amount of energy lost in the Distribution process. Your proposals, while helping to simplify the calculations to be done, are unlikely to achieve much in the way of reduced carbon emissions, and continue to have the potential to damage DNO finances.

Our concerns throughout the discussion on losses have been:

- additional investment in low loss equipment needs to earn more than the standard cost of capital, since it is discretionary expenditure, competing with other optional uses of scarce capital; and
- the volatile nature of past reported performance introduces additional risk, especially if the value of 'saved losses' is increased.

With these observations as background, it is possible to comment on specific elements of your proposals.

We welcome Ofgem's clarification that the target is based on a proportion of units distributed. The use of a percentage target means that the effect of incremental load growth is catered for in comparing actual losses against the target.

We have previously indicated the markedly different results from averaging losses from different post privatisation periods. This led us to conclude that a longer (13 year) average was more robust. However it is very possible that you intend to cover this in the transitional adjustments that are proposed but not detailed.

We share your hope for a substantial improvement in the volatility of settlement data. If this proves to be the case, there would be merit in rebasing the losses incentive at the earliest opportunity (perhaps in 2010). On the other hand, if Elexon's projects fail to deliver the anticipated benefits, there may be a need for a different approach to protect DNOs from revenue uncertainty.

The discussions that we have had on reported losses have been helpful in clarifying the issues and in developing a common understanding of the preferred approach. We support the principle of the simplification of reported losses. However, as the value of the incentive has not been identified, we have been unable to assess the impact of this proposal. Clearly this will impact on our assessment of the need for and value of any protection under the transitional arrangements.

We recognise the difficulty of developing a single approach to distributed generation and welcome the retention of a distributed generation adjustment for special circumstances. We do have some concerns regarding Ofgem's calculation of the minimum level, and on the impact on United Utilities.

The distributed generation incentive rate of £1.50/kW/annum used in the calculation is in fact part cost recovery and part incentive. This incentive is intended to offset the remaining 20% of costs not passed through, as well as providing an incentive. We therefore believe that it is inappropriate to consider the full value of this matching the negative impact of increased losses as a result of a particular generator connecting. We have included a worked example to illustrate our point.

If we consider the connection of a distributed generator at a cost of £50/kW, then under Ofgem's proposal, 80% would be passed through leaving a remaining 20% or £10/kW to be covered by the incentive. Considering the incentive rate of £1.50/kWper annum, this results in an incentive value of £14.1/kW (based on an NPV over 15 years at 6.5%). The net benefit is therefore £4.1/kW over the period or £0.44/kW per annum. The value is therefore less than 30% of the value used by Ofgem in its calculation. In this example the breakeven LAF would be around 0.997. Any distributed generation connection we make at a cost of greater than £70.50/kW (factoring the £4.1 up from 20% to 100%) would actually result in a cost to the business rather than an incentive. We therefore believe that the mechanism used by Ofgem to derive the balancing point between the two incentive mechanisms is flawed.

We anticipate significant connection of distributed generation in Cumbria, an area that already has a high degree of distributed generation and low levels of demand. Our modeling shows that the majority of future distribution generation connected in this area will increase losses. We are forecasting an increase in distributed generation connected, the majority being in Cumbria and the majority having LAFs less than 0.99. We therefore are concerned that the limited form of protection proposed by Ofgem will undermine the incentive benefits of the DG incentive mechanism. The impact of losses (due to the connection of generators increasing losses i.e. with LAFs less than unity) would further compound the reduced returns under the DG incentive.

We believe the level of protection should be set at unity, as the distributed generation incentive does not provide the offset that Ofgem believe, (as demonstrated above). One way for us to mitigate this effect is to reduce the LAF of new distributors connecting, typically resulting in higher construction costs. This runs counter to the intention of the distributed generation incentive to find innovative ways to connect generators without recourse to capital intensive solutions. We would welcome the opportunity to discuss alternatives with Ofgem.

3.14 Price Control for Metering Services

We welcome the creation of a Metering Working Group to encourage dialogue with DNOs on the metering aspects of the review. This should provide a suitable forum to resolve the tensions between distribution and metering issues. However the group will need to make rapid progress as there remain many issues to resolve. We remain very concerned that in the consultation paper your discussion of metering issues continues to focus on the form of the metering price control. This is of less significance than the treatment of costs relating to metering obligations (often in the past), that must be covered by the Distribution Price control. It is essential that the mechanisms for securing recovery of costs (both capital and operating expenditure), that derive from the DNO licence obligations are agreed as soon as possible.

Although you have previously suggested that there needs to be separate consideration of 'distribution' and 'metering' revenues, we believe that this may not prove to be possible. The ability of a metering price control to recover the reasonable allowed costs for metering services, will depend upon the extent of competition. Some means of rebalancing revenue with the distribution control will therefore be necessary. We believe the development of price caps for specific metering services may be most effective. Such an approach could operate within a broader Distribution Price Control until the metering obligations on DNOs are removed. As we have suggested previously, any metering price caps should be restricted to services for standard domestic credit and prepayment meters. The non-discrimination provision in Licences should provide adequate protection for suppliers in other circumstances.

4 Quality of Service and other outputs

4.1 Guaranteed and Overall Standards of Performance

4.1.1 Guaranteed standard on supply restoration

We support the principle to separate supply restoration standard (GS2) to cover normal and severe weather, but have concerns regarding Ofgem's approach to revising the interim arrangements for storm conditions.

Whilst we support the proposed compensation arrangements for normal conditions, we believe that the proposed arrangements to apply under storm conditions will act as a disincentive to discretionary Quality of Supply and Network Resilience investment. Ofgem propose to use different arrangements for different weather conditions; the scale of the event being defined by the number of faults that occur and the proportion of consumers affected.

A DNO that invests in network automation and remote control to improve customer service and to gain rewards under IIP, would (perversely) be less likely to meet any materiality threshold for a given level of storm damage. (Even though there are an exceptional number of faults, if these are restored effectively as a result of targeted investment, the proportion of consumers affected may be lower than the materiality threshold).

Equally, if a DNO invested to increase the resilience of its overhead lines, for a given storm these would result in less CIs, again potentially exposing the DNO to the full value of GS failures below the exemption gate.

We believe it would be more appropriate to link qualification criteria with the events that triggered the interruptions. For example, if a DNO exceeds the proposed materiality thresholds following adverse weather, then any DNO which experienced the same conditions should automatically be classified in the same way. The effect would then be that a second DNO whose network was more robust or with superior restoration procedures, would still benefit from the relaxed GS regime and IIP exemptions. It may take time to develop a robust interpretation of 'similar weather' rules, but this would be a worthwhile exercise to avoid diluting the incentives to maintain high levels of performance.

An alternate mechanism would be to allow each DNO an upfront allowance in anticipation of exceptional events occurring in a given period. The DNO would therefore be incentivised to reduce its exposure to actual GS failures and retain any out performance. This approach would transfer additional risk to the DNO and an appropriate reward would be required, however it would have benefits for customers, as the risks are best transferred to the stakeholder best placed to mitigate them.

4.1.2 Automatic payments

We agree with Ofgem's proposal to introduce semi automatic payments so long as the financial consequences are recognized. The impact of this change for DNOs is likely to move significant costs from current ex-gratia expenditure to increased Guaranteed Standards payments. However it is important to note that fully automatic payments are not possible as we do not necessarily know the name of the occupier of a property to whom a cheque should be sent.

We also know that many customers, (typically 40%) do not claim, even when invited to do so. It is therefore clear that a revised process that assumes payment is made, one way or another, to all customers will substantially increase our outgoings. This and the additional administrative cost will need to be built into the base costs for 2005-2010.

4.1.3 Compensation for business customers

We are pleased that Ofgem recognize the impracticality of providing differential service levels to business customers connected at LV and support the proposals for the GS arrangements to remain the same for all customers connected in a similar way.

Whilst we await the willingness to pay survey results, we believe that consumers connected at HV and above have the opportunity to positively determine their level of supply security. It would certainly not be appropriate to make large GS payments to HV consumers who have chosen less secure connection arrangements. We would still be wary of the potential impact on restoration policy, which currently aims to restore the highest volume of supplies in the shortest possible time, should any differential arrangements be implemented for this group of consumers.

4.1.4 Priority Service Consumers

We support Ofgem's proposal not to introduce a separate new standard focused on vulnerable consumers, and agree that the other potential approaches would be more effective in improving service to this group of consumers.

4.1.5 The role of the Overall Standards

We agree with Ofgem that Overall Standards have served a useful purpose, and that a positive development is now to incorporate these measures in the RIGs monitoring and reporting framework.

4.1.6 Other amendments to the Guaranteed Standards of Performance

We agree that the existing suite of Guaranteed Standards provides sufficient incentives to deliver good levels of consumer service and an appropriate level of compensation where these levels are not met.

We also consider that the existing EGS2a multiple interruption standard provides adequate protection to worst served consumers, and that the proposals to incorporate performance reporting into IIP will adequately help to narrow the gap between average and worst service experienced, without the need to increase the level of this standard.

4.2 Reviewing IIP

4.2.1 Provision of disaggregated interruption data

We are broadly supportive of the move to provide disaggregated data as proposed, however we do not accept that no additional revenue should be allowed to cover our costs. As with all other data it is important to appreciate that the one-off cost of providing an informal data extraction is not representative of the cost of ongoing provision in a well defined and fully audited manner. The refinement of rules and guidance from this process is likely to involve system changes and therefore creates costs for the DNO. A move to a disaggregated data submission should therefore be accompanied by appropriate funding.

We note, and welcome Ofgem's intention not to introduce performance targets in respect of these measures at this review.

4.2.2 Worst served consumers

We agree with the importance of ensuring that incentives under IIP to improve average performance are not having a detrimental effect on worst served consumers. We agree with Ofgem's reporting proposals and are supportive of HV interruptions being the most appropriate measure.

We believe that whilst multiple interruptions are not necessarily the key drivers for investment targeting, there is a definite coincidental improvement for worst served consumers by improving overall average network performance.

4.2.3 Form of the incentive scheme

We welcome the proposals to move to an annual incentive scheme, on the basis that given long term stability in the targets, and the incentive rate reflecting a reasonably constant willingness to pay, then the fluctuations around average performance should balance out.

We also support Ofgem's thinking of not introducing deadbands or rolling averages. We still believe however, that the stability of IIP depends upon removing the impact of substantially abnormal events. In our own case, 2002/03 performance was significantly distorted by a small number of EHV faults that happened to have a particularly large consumer impact. These events were outside the probability range we modelled before accepting the IIP targets. In these proposals Ofgem now intend to exclude exceptional severe weather; we consider that other exceptional events should also be excluded from reported performance.

With regard to the mechanics of the scheme, we would prefer rewards and penalties to be used to adjust allowed revenues on an annual basis. This would ensure that the impact of any penalty or reward could be passed on to customers annually rather than potentially far greater impacts being passed on at the end of the next price control period. Another additional benefit for DNOs is to assist annual cashflow forecasts and therefore reduce exposure to large potential changes at the end of DPCR4.

4.2.4 Weighting of planned and unplanned interruptions

Whilst we agree that consumers have a greater opportunity to mitigate the impact of a planned interruption, we foresee problems with applying different weightings to planned and unplanned interruptions.

The willingness to pay survey will provide an important input to this decision, however it is likely that consumers will place relative weights, based on their current experience of planned and unplanned interruptions. With existing equal weights, DNOs are incentivised to consider the most efficient approach to providing consumer service, whether planned or unplanned. This may include the use of outage avoidance approaches such as provision of generators or live line working. If the weighting of planned interruptions is significantly reduced then there may be less incentive to avoid planned outages resulting in consumers experiencing a worsening service. Furthermore, applying different weightings to planned and unplanned interruptions places an additional complexity into the operation of the IIP scheme, in general, increasing the potential for inaccurate performance measurement.

We believe that by maintaining existing equal weightings, and reflecting these in incentive targets, companies will identify the most cost effective approach to interruption management.

4.2.5 Audits and adjusting data for inaccuracy

We support the principle of improving the IIP audit framework for the next price control review. The obvious benefits being to reduce audit costs for both Ofgem and DNO's.

In considering the two options being considered we have the following observations:

a) Option 1

We would disagree with any proposal to streamline the audit if this resulted in a reduced data sample size. Reduction of the sample size reduces the confidence in the survey results and statistically invalidates the use of the result for correction of the reported performance figure. The RIGs require accuracy of the overall reported figure not of each fault event. We commissioned expert statistical work from UMIST in 2001 to illustrate this point. This was subsequently accepted by Ofgem. To use mathematically invalid sampling techniques and then apply micro level errors to the macro population exposes a DNO to unacceptable risk of loss of reward or incurring a penalty. However, if streamlining the audit resulted in removing annual duplication and audit process then this would be beneficial.

b) Option 2

We would support the proposal for random audits along the lines of the current audit process subject to certain clarification of the potential penalties and the mechanics of application of any such penalty. We do however, believe this option transfers additional risk and cost to DNOs.

We remain to be convinced that the proposal to adjust data for any inaccuracies is statistically valid. In essence the proposal will apply an adjustment to a degree of accuracy that the base data accuracy does not support, and therefore suggest Ofgem reconsider this proposal to maintain the existing adjustment thresholds. If Option 1 above were implemented on a relatively small data sample with a potentially reduced confidence level, then this problem would be particularly apparent.

4.2.6 Target setting

We note Ofgem's intention to address the future IIP targets in the June proposals. In advance of those proposals, it is appropriate to reiterate our views on how these targets should be set.

We have consistently maintained that the current Quality of Supply targets should be retained, and that long-term stability in the targets is beneficial to consumers. We have no evidence that customers would prefer to pay more for a higher quality of service. However, we are prepared to review any alternative evidence from Ofgem's consumer survey against the costs identified in our mid-January FBPQ submission.

Furthermore, we believe it would be more appropriate for Ofgem to set marginal rewards that reflect customers' valuation of incremental changes in quality and leave companies to identify the most cost effective outcome.

4.2.7 Treatment of planned interruptions for the final year of this price control period

We disagree with the proposal to allow roll forward of CIs and CMLs from 2004/05 to 2005/06 on the basis that it is in effect a dilution of the incentive mechanism. DNOs that have made early discretionary investment to ensure achievement of 2005 targets are relatively disadvantaged by this proposal. In addition we believe that it has the potential to store up problems for DNOs in the future, especially given the uncertainty of where the 2005/06 target levels will be set, and the potentially different relative weightings of planned interruptions to unplanned interruptions as described in 4.2.4 above.

4.3 Network Resilience

We acknowledge the difficulty Ofgem has experienced in deriving a robust measure for defining resilience however, we believe that it is still a realistic goal for the introduction of such a measure and associated incentive mechanism during the next price control period.

We note Ofgem's proposals to exclude all CIs and CMLs relating to severe weather from the IIP incentive scheme and the proposals for differering weather condition categories.

We have set out in section 4.1.1 our objections to defining the scale of an event by using a metric that includes the number of consumers that are affected by the event, based on the fact that any discretionary QoS investment is potentially penalised. This argument follows through into the proposals for categorisation of severe weather events. For example, a DNO that has invested in QoS improvements may find themselves experiencing a large number of faults which may put them into say the "smaller" event category, but due to additional remote control and automatic reconfiguration of the network, large proportions of consumers associated with those faults are restored within three minutes, and therefore overall the DNO fails to meet the materiality threshold for number of customers affected. If this threshold is not achieved then perversely it may be deemed by Ofgem that severe weather was not experienced. This has the impact of added exposure to Guaranteed Standard payments without the potential protection of extended time period triggers or any pass through of costs.

In considering the risk for DNO's in relation to severe weather, and the application of any exposure caps, it is important to initially reflect on the exposure of DNOs at the time of the last price review. At the last price review when the cost of capital was set, DNOs had no exposure to severe weather under the guaranteed payment scheme because of the exemption. Increasing DNO risk could therefore increase the cost of capital. To limit such increases which feed through to prices to consumers it is important to set exposure caps for DNOs that limit the risk to a reasonable level.

4.4 Telephone response

We welcome Ofgem's proposal to expand the survey to include calls answered by automated message in the next price control period. However, we await with interest the results of Ofgem's review of the technical constraints, in particular how you identify a customer who has used the automated message.

The proposal to combine 'politeness' and 'willingness to help' into an overall helpfulness question is sensible, potentially removing an element of subjectivity from the survey. We look forward to working with Ofgem to consider the appropriate form of the survey questionnaire.

Given the convergence of companies' performance, there is more value in moving to an absolute performance target that rewards improvements in performance, whilst not necessarily penalising the lowest scoring company, so long as they continue to meet customer expectations.

4.5 Environmental outputs

We support in principle the environmental reporting framework as suggested by Ofgem however we do need to fully understand how Ofgem intend to use the information gathered. If say a league table were to be produced of performance against each of the metrics suggested, and in particular SF6 or oil pollution, then we would need to see robust measures which are adequately comparable across all DNOs, with fully developed RIG definitions, and an audit process to ensure fair reporting of performance.

We agree with Ofgem that the output measures should not be subject to financial incentives particularly given the issues of comparability set out above, and look forward to working with Ofgem on developing a robust set of measures.

4.6 General discretionary reward

We are interested in any additional incentives schemes relating to service quality that Ofgem propose outside the existing arrangements. However our view is that such schemes should not reward companies for merely achieving licence conditions, e.g. effective communication during a severe weather event. This may also be unfair on a DNO who by effective asset stewardship avoided the impact of such a potential event in the first place.

Best practice towards priority consumers may be a suitable area for such incentives. It may also be appropriate to identify other areas that are measured but not incentivised, e.g. consumer complaints performance or asset risk management survey best practice performance. It may be a role for energywatch to suggest suitable criteria.

5 Distributed Generation

General

We continue to welcome Ofgem's intention to introduce an incentive framework for DNOs in relation to the connection of distributed generation, and are pleased to note the increasing clarity with which the details of the incentive régime are described. We recognize the progress that has been made in designing the scheme and support its underlying objectives.

Our chief remaining concern is that, whilst providing a strong cost-efficiency incentive, the proposals may not go far enough to provide a genuine driver towards growth in DG connections. We make suggestions in our specific comments, below, as to how the twin issues of risk and return could be addressed in order to overcome this concern.

The considerable problems we all have in predicting real DG growth give rise to particular difficulties when considering the issue of strategic investment for speculative infrastructure build, especially at 132kV. Our concerns here relate not only to the incentive scheme failing to bring forward necessary strategic reinforcement, but also the potential volatility of GDUoS charges should such investment go ahead. We remain of the view that strategic investments should be treated separately from the incentive régime for "standard" DG connections.

Similarly, we believe that microgeneration does not lend itself to treatment under the incentive scheme, and suggest a way forward for this area in the detailed comments below.

Specific Comments

5.1 Level of pass-through

We have previously argued that it would not be inconsistent for an incentive on the DNOs to be accompanied by 100% pass-through of costs. However, we accept Ofgem's position that the scheme design needs to balance an incentive for cost efficiency with the overall objective of encouraging DNOs to be proactive in connecting DG to their networks. We agree that this balance is achievable with a pass-through rate of 80%, however we also believe that this level has implications for the appropriate floor on risk and also for the level of return, both of which need to be addressed for the overall package to be acceptable. These points are expanded upon below.

5.2 Recovery of pass-through costs

It is not clear from 5.15 that this paragraph applies equally to under recovery as well as over recovery. We believe that it should, with any deviation by more than 2% from allowed revenue being recovered from the total customer base. We assume that this will be relatively straightforward to implement in the price control algebra, where it will be possible to calculate year on year the allowed revenue under both the existing control and that to encompass DG, and to make adjustments to allowed income and charges accordingly.

5.3 Treatment of stranded assets

In terms of return, scheme performance is based on the twin supposition, as you remark both in Chapter 5 and in the SoC & DG RIA, that not only does the generation connect in the volumes and costs predicted but that it remains for the envisaged asset life too. We note that the downside has a floor of the cost of debt (assumed 5% in our own modelling), and although welcoming this, we will struggle to accept an incentive scheme that exposes us to a downside over which we have so little control – as pointed out in 2.22 of the SoC & DG RIA.

We maintain that the risks identified above should be addressed more directly in the scheme design by fixing the term of incentive payments to 15 years, even if the DG ceases to operate, and for the payments to be due as soon as the DNO has made the commitment via a signed connection agreement.

We note Ofgem's view that capacity built for DG can be reallocated to demand should the capacity become used by demand. Whilst acknowledging this point, we do not see it as material as most DG inspired reinforced shared assets (eg thermal export capacity or fault level driven switchgear replacement) are unlikely to be used to support demand – or at least not to an extent greater than the pre-existing capacity.

5.4 Value of the incentive rate

It is important to recognise that the level of incentive rate is set on the basis, not only of the DNOs' reported costs, but also the design criteria set out in the December DPCR consultation.

With regard to the DNO cost assessment, whilst we appreciate that average connection costs may vary because of geographical differences, it would not be appropriate to allow companies higher rates just because their estimation processes have been different. We need reassurance that proposed variations in rates reflect genuine cost differences.

With regard to the design criteria, we believe that a significant step towards satisfying our concerns regarding downside risk could be made by aligning the criteria used to set the incentive rate with the proposed cap on costs/floor on return, as described below.

In (5.22) the design criteria put forward in the December paper are used to derive an incentive rate of £1.5/kW/yr from the £50/kW and 80% numbers. In particular, one of the suggested criteria is that a return of 5% should be achieved at a cost level of £120/kW. We also note the intention (5.29) to set a floor on return equal to the allowed cost of debt (assumed here to be around 5%) and also (5.34) cap the cost to the DNO of "high cost" projects at £200/kW. It is apparent to us that this structure leaves a disjoint in the risk profile for costs in the range £120/kW to £200/kW and suggest that this risk could be covered by adjusting the design criterion for 5% return from £120/kW to £200/kW.

5.5 O&M costs

We believe that O&M costs associated with DG will go up, not down, as increased levels of DG require more management. We expect that O&M charges will therefore rise if anything, rather than fall as indicated in 5.25. We also expect O&M to last the lifetime of the connected DG. The MM-BPI report (p54) supports the level of O&M charged by UU currently, but of course this does not take account of the increased costs caused by active network management or opex arising through ancillary services contracts. We are concerned that not all opex costs that we foresaw in our DG BPQ have been taken into account and we return to this below under Ancillary Services.

We note that you do not appear to have provided a justification for applying a different methodology for the recovery of generator O&M from that used for demand. Recovering O&M through a £/kW driver further penalises the DNO where generators are seeking to connect in remote, high cost, areas. It would seem more sensible to us to add O&M to capital scheme costs as at present (and indeed as for demand) and subject the whole package to an adjusted incentive scheme, ie based on (using UU's numbers) £57/kW (£50 +14%).

It is not clear from 5.27 whether DNOs will continue to earn any incentive on assets that are over 15 years old. We understand 5.27 to say that assets built under a particular incentive arrangement will earn the same incentive rate for 15 years and then the ongoing incentive rate could be reset. Neither can we see how O&M costs are recovered from assets older than 15 years, although clearly they should be.

5.6 Ancillary Services Payments

We are surprised that there is no discussion of ancillary services payments in the March document. We expect these payments to figure in our cost base 2005 to 2010, although clearly as with all DG issues, we are quite uncertain as to their volume. We believe that specific allowances will need to be made for these costs. We do not believe that there is any argument to fund these costs out of the incentive payment (as this is to recover investment costs with risk premium) nor from O&M as proposed (since it has been set on a basis not including assumptions about these costs, and since there is no common understanding of the likely scale of the costs).

We are mostly concerned about the prospect of contractual payments that we believe will be appropriate to generators who are providing system security under the proposed ER P2/6, and we know that Generators raised similar concerns at a recent ISG meeting. Without an appropriate price control treatment of such contractual costs, DNOs will be prevented from rewarding generators for system security contributions. These costs will need to be treated as a cost to be borne by demand customers and therefore be factored into the main price control calculation.

5.7 Floor and cap on DNO returns

We are disappointed that Ofgem have chosen to cap returns at 2 x WACC. We maintain that 3x is more appropriate given the almost unmanageable uncertainties of DG growth. We note that 3x is the maximum return allowed to Transco for the NTS expansion, and it is not clear to us that there is any more uncertainty or risk in NTS expansion given the information available to Transco from the auction process.

We note in 5.31 that you propose to cover any shortfall below the floor from incentive rate adjustments at the next price control review. Whilst agreeing that this will probably work, given our concerns about the barriers to DG that higher, and particularly volatile, charges represent, we believe that it would be helpful if the shortfall is funded by all network users. We also have concerns that significant underfunding should not need to wait for the next price control, although this issue is likely to be affected by the eventual treatment of strategic reinforcement. If no specific arrangements are made for strategic reinforcement, the lack of an interim mechanism for putting a floor on returns will disincentivise DNOs from making such investments. To counter this we believe that it is necessary to formally establish the return on DG schemes every year, probably as part of the Price Control allowed income returns. There needs to be a mechanism built into the price control algebra such that adjustments can be made year on year should the returns fall outside the collar and cap.

5.8 Strategic investment & "High cost" projects

We believe that it is helpful to consider how decisions regarding strategic reinforcement might work in practice. The DNO will be connecting generation in a constrained area, with, all other things being equal, generators being constrained to a level that the DNO finds economic, given the penalties for network unavailability proposed in 5.39. Once this limit is reached, the DNO will propose a connection to the next generator that includes strategic reinforcement, the cost of which will almost certainly breach the £200/kW threshold proposed in 5.34.

Our interpretation of 5.34 is that the connection quote will include the "excess" costs of the reinforcement, ie essentially a reversion to "deep" connection charges, which would deter the generator and the strategic reinforcement would never be built. In order for the DNO to go ahead anyway with the investment (ie without the critical generator paying the strategic costs) the DNO would not only have to be reasonably sure that it could influence a certain volume of other new generators to connect and use this capacity but also see the possibility of a return commensurate with discretionary investment.

We note that "deep" charging conflicts with the guidelines for Connection Charging Boundary Rules set out in the latest Structure of Charges update document, and also note an alternative option of passing the "excess" costs on into the RAB rather than to the generator through connection charges. It would of course be necessary to pass on 100% of such costs in order to provide the DNO with the required level of protection.

The second problem caused by the proposed approach is that should the DNO make a strategic investment, the effect on GDUoS will be pronounced. Although the DNO might have sufficient planning time to reflect such costs into GDUoS forecasts up to a couple of years ahead, this is probably insufficient for generators who will need to be able to build fairly certain cash outflows into their business plans in order to secure funding.

We continue to believe that strategic reinforcements should be agreed ex-ante (as they are for demand) and included in the existing price control arrangements. Alongside such a treatment we are beginning to think that it would be appropriate to have a generation security planning standard for distribution networks. It has seemed anomalous for some time that there is no such standard for distribution systems when it is such an important feature of transmission arrangements. Apart from providing a benchmark against which efficient generation-related system reinforcement can be judged, the lack of such a standard gives rise to two more future problems. The first is system stability and security. Your own IFI and RPZ RIA specifically cites this issue as a future problem in 2.57. A generation planning standard of some kind will be necessary as a component of the overall technical solution – not least in defining the acceptable boundaries of the use of intertripping for example. The other problem that a planning standard will help overcome is in deciding the charging boundary. ISG are currently thinking of charging rules incorporating ratios of generation to system capacity. Apart from simple radial systems, it is debatable what is meant by system capacity for complex interconnected systems, as there are numerous criteria (thermal, steady state and transient stability, steady state and transient voltage, fault level, etc) that must be satisfied, any one of which can define the system limit. Without a clear concise generation planning standard that defines limits for these criteria, there is likely to be significant future disagreement over system capacities. UU believes that the time is now right to start to consider the content of such a standard and we would be happy to discuss this issue further with you.

5.9 Microgeneration

We believe that there is an important difference between microgeneration connected under G83/1 and other generation. Under G83/1 DNOs have no advance warning of the DG connection (at least for individual units – G83/1 Stage 1 approach) and can only react. For larger installations DNOs are given notice in normal planning timescales (G83/1 Stage 2 approach). Theoretically, therefore, it is conceivable that two distinct approaches could be taken, whereby Stage 1 applications are treated as domestic demand is now (ie ex-ante allowance based on assumed need) and Stage 2 applications are subject to the incentive arrangement. However given the enormous uncertainty over costs and volumes we would argue that for the 2005-2010 period all microgeneration is given an ex-ante treatment in line with our DG BPQ submission of £7.2M of allowed capex. There should also be an agreement by Ofgem to allow ex-post at the next price control any reinforcement expenditure that outturns significantly higher than this. For the avoidance of doubt we see that greenfield new build incorporating significant penetrations of microgeneration will not need special treatment as both the marginal costs of designing in microgeneration are modest and can be covered through the normal connection cost recovery process.

We would expect to work with Ofgem and others once microgeneration starts to be connected to networks to understand the true costs and to seek appropriate incentive arrangements for the period following 2010. In suggesting this, we are conscious both of the shortage of existing experience and recognized engineering solutions, and also the likely high cost per MW of microgeneration reinforcement (> £200/kW in our DG BPQ submission) which makes it unsuitable for the incentive scheme as currently envisaged by Ofgem.

5.10 Network Access

We have previously submitted our ideas on network access incentives to you in a separate paper in December. We do not believe that the incentive properties of what is in effect a fine for network unavailability are as great as a genuine incentive where a DNO can earn more for increased availability.

We believe that it is a simple matter to take the £/kW incentive and turn it into an effective £/kWh incentive. This avoids the complication of deriving an arbitrary fine such as the £0.002/kWh proposed in 5.39. We propose that an overall incentive for DG (for connection and for network access) could take the form of an incentive payment for availabilities in the range 0.9 to 1 where availability is defined as follows:

$$Availabiliy = \frac{MWh_g}{MWh_{MAX}}$$

$$MWh_g = MWh_{MAX} - \sum_{i=1}^{n}\sum_{j=1}^{m} MW_i \times U_{ij}$$

$$MWh_{MAX} = 8760 \times (0.96 MW_{NF} + MW_F)$$

$$MW_{NF} = \text{MW connected non - firm}$$

$$MW_F = \text{MW connected firm}$$

$$MW_i = \text{Capacity of generator i}$$

$$U_{ij} = \text{unavailability in hours during outage j on generator i}$$

m is the number of outages on generator i and n is the total number of generators. Note that this approach relies on system outage data from DNOs, not on metered volumes. We have further comments on data below.

In the formulation above 0.96 has been chosen as a typical duration of network availability of non-firm connections, with firm connections assumed to be 100% available. The intention is that any deviation from 100% availability for firm connections will reduce the payment by the generator, whilst availability above 0.96 will result in an increased income from non-firm generators. Therefore, in this example an underlying rate of £1.56/kW/Yr would be compatible with the £1.5/kW proposed in the Ofgem incentive scheme. In each year this could be recovered so that at 90% availability, the reward is nil and at 100% it is £1.56. This implies a rate of 15.6p per 1% availability above 90%, which could be represented as 0.18p/kWh (where the qualifying kWh are those above an availability threshold of 90%). There would be no payment (and no fines) for availability below 0.9 – and crucially for the DNO, only the 80% pass through of costs.

We continue to believe that this is a simpler overall mechanism for combining an incentive for ongoing network access with the incentive to connect.

If Ofgem's own suggestions for the £0.002 /kWh fine are implemented we strongly recommend that the fine is made consistent with the arrangements for demand customers and that no payments are made for the first 18 hours. Only if unavailability persists for more than 18 hours should the fine be payable, and then, as with demand customers, counted from the time of first unavailability. This approach would considerably simplify payment methods, as to pay a fine for every hour from first unavailability could imply new measurement systems.

5.11 Modelling the incentive scheme

We support the RAB approach to setting charges. Whilst agreeing that an annuity approach has the potential to give slightly more stable charges year on year, we believe that this effect would be swamped in practice by the volatility introduced by the uncertain rate of growth and cost of DG, particularly where strategic investments are contemplated. A more important practical consideration is the possibility of "excess costs" (ie costs that would otherwise cause the return to fall below the cost of debt) to transfer across from the "Generator RAB" to the "Demand RAB". This process should be simplified by the methodologies being aligned between the two RABs.

5.12 Definitions and Reporting

The quantities relating to DG that are required to be measured are generally those that are already recorded by DNOs for business as normal. The key aspects of any DG installation, including commissioning dates and MW of capacity are already kept. These can be made available for auditors at little additional cost. Similarly any outage data that is required for a network access incentive is, or can be, recorded in the same way as outage data is currently reported into NaFIRS and is reported under IIP. We agree that it will be necessary to add appropriate definitions to the RIG to facilitate this. Probably the most onerous definitions to draft will be those differentiating between shared and sole use assets and defining the connection charging boundary. We would expect ISG to develop and document these.

We believe it is worth pointing out here that should the DG incentive apply to microgeneration there will be additional system and opex costs in maintaining an auditable database of microgeneration installations. Whilst we in general expect to keep more information about the presence of microgeneration on our networks, there are costs associated with maintaining data of sufficiently high accuracy for financial, as opposed to engineering, purposes.

5.13 IFI

We support the general approach taken by Ofgem on IFI, although we remain concerned that the level of funding might not be appropriate. If the DNO was the beneficiary of all the savings then the 80% level might be appropriate. However, where generators and generator connections are involved, it is likely that the benefits of innovation are reduced (capital) connection charges together with higher opex. As such there is little incentive for DNOs to fund the 20% for this area of innovation.

We support the intention to restrict the amount of expenditure in-house, and agree that 15% seems an appropriate level. However, we believe that there needs to be some flexibility here as there may well be some innovation projects where it is appropriate for a higher proportion of DNO spend. For some projects we can foresee that a greater proportion of the cost may be needed to fund work within the DNO to cover activities such as data gathering or trial set ups, prototyping of safe systems of work etc; ie work for which the DNO has the most appropriate technical expertise. Such areas cover many of the high volume activities that have a direct impact upon customer service levels. These will probably be a minority of IFI funded projects, but we need an appropriately flexible framework to support them.

The level of funding apart, the rest of the IFI proposals seem appropriate and sensible. We also support an early start to the scheme and would look to suggest some projects by Autumn 2004. Clearly we need to understand what the pass through element would be in this first year (we would argue for 95%), and the effect on subsequent years (we would argue for no change from your existing proposal).

We are very keen to work with Ofgem and others to establish the good practice guidelines as soon as possible. Paragraph 5.50 does not state that there will be a need to define how the added value, benefits etc, are to be judged and the amount of prospective improvement or innovation which is considered sufficient to warrant inclusion with the IFI scheme. We believe this will be an important part of the Guide, and not a trivial undertaking. There is a wealth of existing expertise and practice in the research communities as to how to define costs and benefits of research. We believe that IFI guidelines can be drawn from the approaches used by DTI, ESPRC, STP, EEC research grants etc. It is also reflecting Ofgem's point about the atrophy of R&D in DNOs in recent years in that DNOs currently have very few skills in designing or responding to such guidelines.

We are not immediately convinced that the development of these can easily be combined with the work that you state the TSG is to undertake on defining RPZ criteria. The requirements for a rule base within which R&D projects are to be selected and progressed to the point of delivering benefit are rather looser than those we envisage for RPZs. Our view is that this work will be completed more quickly and effectively if carried out by those who have experience in compiling and managing R&D work programmes for which an appropriate example of this is the Strategic Technology Programme operated by EA Technology Limited (EATL). We would strongly support Ofgem engaging EATL to assist with this development, not least because it is hard to imagine the TSG, particularly with its ponderous procurement process, being able to take this work forward in time to meet the Autumn 2004 timescale.

5.14 RPZ

In general we agree with your design of the RPZ scheme and support it. However we have a couple of outstanding concerns.

As we pointed out in Section 5.6 of our response to the December DPCR policy document, we believe that significant penetrations of DCHP will raise technical issues related to voltage control and it is therefore appropriate in our view that the attempts to resolve these efficiently attract an incentive and RPZ status for the first instances. Given that we do not believe it is necessarily appropriate for DCHP to attract the DG incentive it is critically important that another method of rewarding innovation and demonstration is found. The difficulties are not simply related to the method of incentivization: the nature of DCHP means that costs/MW will be very high and it will not be appropriate to use a £/kW basis. Again as suggested in our February response it might be appropriate to consider a reward based on the avoided cost

There will also be instances in most networks where a generator already exists, and the opportunity will arise to make use of that generator to provide system support or to otherwise interact with demand in novel ways. As currently envisaged, this instance could not be registered as an RPZ as there are no additional MW being connected to provide the RPZ income driver. We believe in this case that it would be appropriate to declare an RPZ and again that the value of deferred or avoided reinforcement capacity could be the RPZ income driver.

We believe that a useful start for the defining criteria for RPZs has been made in the RIA for RPZs by including existing possibilities for demonstration. We support this and believe that any technique for assisting in the connection of generation not hitherto used by the DNO should be allowable.

Finally you ask about barriers to the introduction of RPZs. We believe that you have covered in the consultation paper those that we can think of, and these are principally the risks to the DNO from compliance with statutory and licence obligations. We note Ofgem's comments on derogations, but we believe that statutory issues are likely to be those which make the design of effective RPZs the most difficult.

6 Assessing costs

6.1 Review of Forecasts

The work on cost assessment is the most important aspect of the price control review. It will underpin the review of performance in the current period and provide the basis from which to project future revenue requirements.

Ofgem's approach to reviewing companies' FBPQ's when assessing costs is a vital part of the cost assessment process and we particularly welcome Ofgem's intention to take more account of companies' cost forecasts in this price control review. We outline in Section 6.6 of our response how we believe that Ofgem should take proper account of companies' own forecasts. We appreciate the need for some form of validation, based on the modelling techniques proposed, but we expect our estimates to be used as the basis of revenue allowances so long as they fall within reasonable bounds.

We also support the work so far to establish a consistent and comparable data set from which to assess companies' efficiencies. This work needs to be completed as an urgent priority. We are pleased with the general approach Ofgem has taken to this work, and support the continued emphasis on transparency, consistency and comparability. However, we remain concerned by the amount of work that still has to be done, the slow pace of progress in establishing a consistent data set for analysis and the relatively late stage in the price review process when we will be given the first opportunity to see early results.

Successful implementation of analysis in this area of the price control review will depend upon full appreciation of the distinction between the efficiency assessment process on the one hand and the cost projection process on the other. We would expect Ofgem to use any predictive capability of the comparative efficiency work to validate the reasonableness of a company's own forecasts. We outline in Section 6.6 of this response our view of the suggested stages of analysis in setting operating cost allowances, which go to make up allowed revenues. We hope that this is helpful and expect discussion of this topic to be a crucially important area of the price control review in the next few months.

We have already sent to Ofgem our views on specific aspects of the cost assessment work, which help to clarify aspects of our views on the necessary analysis and which help to avoid confusion in this area.

6.2 Cost Normalisation

We share the common view on the importance of data normalisation and that comparison of performance can only be meaningful if the data used has been prepared on a consistent basis. Ofgem's general approach to normalisation for accounting and other differences is especially welcome as a novel development in this price control review. It is all too clear that this work needs to be completed as soon as possible if the overall timetable is to be met.

We recognise the lengths Ofgem is going to in order to deal with inconsistencies in companies' reporting. To the extent that Ofgem remains concerned with the latest position, a firm of accountants could be employed to refine the data set used. There is still, therefore, sufficient time to resolve these important matters.

Whilst we fully support the argument that a more disaggregated approach should make it easier to identify cases of potential inconsistency, detailed analysis of data at a high level of disaggregation will not result in valid or helpful comparisons being made. Comparisons will need to be made at a more aggregated level of data. The granularity which is helpful for normalisation should not be used as the basis for comparison. The granularity of the comparative analysis should therefore not be increased as a result of Ofgem using all of the detailed data now available to investigate an increasingly small sub-set of costs. Analysis should rather focus upon investigating an aggregate of adjusted costs in total.

6.3 Normalisation Adjustments

The more adjustments made and granularity brought into the operating cost analysis, the greater the danger that comparisons will be flawed because different companies classify costs in different ways. Only when looking at total expenditure can one really address this issue in a reliable manner. However, Ofgem have indicated that they see a number of key normalisation issues to be resolved and so we have set out below our views on these:

- Faults - all faults should be included in any cost comparison to avoid difficulties over classification between fault and non-fault costs. Care should be taken to ensure all companies are putting similar types of costs into non-fault capital costs;

- Atypicals - high costs for atypical external events should be removed (such as for storms) but adjustments should not be made for internally driven atypical volumes of work (such as in the case of a particular focus on a tree-trimming backlog in one particular year). Since all companies work to overall annual operating cost budgets, if costs in any one area are atypically high, then it is likely that in another area they are constrained to be atypically low. If only the atypically high costs are taken out, and adjustments are not made for the atypically low costs, then this will tend to build a bias into the normalisation. All companies will incur some atypical costs in the five-year price review period, therefore, some atypical cost allowance should be built back in;

- Corporate costs - no adjustments are necessary for corporate costs, since if there are inefficiencies in a certain company because of high costs in this category, then that will be evident when the efficiency comparison is performed;

- Margins - as with corporate costs, this category can be dealt with as part of the overall efficiency comparison;

- Insurance – we understand that Ofgem wish to normalise for storm costs, and so we believe that it is sensible to remove storm insurance costs, but that these should be built back in to allowances after the efficiency comparison is made;

- Non-operational depreciation - as with margins, these costs do not need to be removed;

- Transport costs - if non-operational depreciation is not removed, there is no need to normalise between those companies which have their own fleets and those which lease vehicles;

- Lane rentals - lane rental trial and congestion charging costs are only incurred in four regions. These should be removed prior to comparison. A separate mechanism for dealing with future costs in this area should be developed elsewhere in the price control review;

- Pensions - we agree with Ofgem's proposal to take out the actual pension costs and to replace these with a "normal" level in order to aid comparison between companies which outsource a function and those which do not;

- Capitalisation – adjustments should be made for differences in capitalisation policies; and

- Overheads - this is likely to be the biggest area for adjustment. There is therefore a need to understand fully the treatment of overheads where a service provider holds all costs for a “shell” licensee. The purpose should be to ensure overheads are attributed to activities in a consistent way across companies regardless of organisational structure. Again the purpose is to achieve full cost allocation across activity headings.

6.4 Other Normalisation adjustments – Metering

We recognise that Ofgem might wish to remove metering costs as part of the normalisation process being used to provide input data with which to compare companies’ costs. However in terms of formulating the price control and the associated revenue allowance, operating costs with respect to metering should not be removed into the separate metering control if they relate to possible stranded costs associated with historical and future last resort licence obligations. Legitimate costs in these categories (such as pensions costs) should form part of the main price control. In the meantime, we hope that further clarity on how metering is to be dealt with will emerge from Ofgem shortly.

6.5 Bottom-up Modelling

Bottom up models of costs should be used to validate normalised activity costs and will therefore need to operate with adjusted data provided by all companies. We hope that the models that Ofgem develop in this area will be based on the tools used by DNOs. Models should be sophisticated enough to pick up inter-company variations (such as the impact on fault repair costs of asset age and type, or the effect of a condition-based approach to maintenance planning). We would like to be given the opportunity to understand PB Power’s bottom-up modelling of future capital costs and any associated inputs – such as unit costs.

6.6 Top-down Analysis

It is important to be clear about the use to which the benchmarking analysis will be put. We would expect Ofgem to use such predictive work to validate the reasonableness of a company's own forecasts. We are pleased that so far in the price review Ofgem has remained open-minded on the comparative efficiency techniques to be used. We believe that Ofgem should use the output from a range of analysis to validate, rather than set, cost estimates.

The uncertainties in any 'top-down' analysis are substantial. It is therefore unlikely that it can be disproved that all companies are approximately equally efficient. However the analysis should not be prejudged and Ofgem needs to conduct the important step of deciding whether the comparative efficiency analysis shows reliably that there is a difference in efficiency between DNOs.

Explicit consideration of this point is essential because it will enable Ofgem to consider whether there are any explanatory factors, other than differences in efficiency, which might describe observed differences between companies from the initial regression work. Analysis that we have undertaken shows that when considering regressions using operating costs and total fault costs, there are a number of factors that have significant explanatory power, namely:

- Capital expenditure - we have been pleased to date to note that Ofgem intend to continue exploring the use of total cost analysis and within that approach we agree that different measures of capital should be considered. We would prefer to see an appropriate measure of capital consumption added to operating expenditure. Subject to the agreement of an appropriate definition of capital consumption, we would expect a measure of total cost to be the most helpful in examining comparative efficiency. A workable mechanism to incorporate total costs in a revenue setting methodology is superior to that currently envisaged by Ofgem and we will be sharing our ideas further with Ofgem on this in the near future.

- Mergers - we continue to favour an approach that concentrates on the 8 management teams rather than the 14 licensees, although we appreciate that you will eventually have to calculate allowed revenue on an individual licence basis.

- Quality - we have explained before the importance of including quality of supply in any comparison and we have suggested ways of doing this that use Ofgem's own valuation of marginal changes in service (as defined in IIP).

In addition, there are further variants of valid analysis that both we, and CEPA, and no doubt Ofgem, have considered. The main point is that one single set of analysis does not present a complete picture to assess relative efficiency.

Examination of relative efficiency should be a prior step to the one to determine future cost allowances. The two steps should not be conducted simultaneously in one analysis, since a range of evidence is relevant to the second, and all relevant information needs to be taken into account.

We outline below how Ofgem can incorporate judgement to their analysis and yet can remain transparent by: (i) taking analysis of a range of factors in regression type analysis;(ii) not assuming that all differences in any one analysis are explained by inefficiency; (iii) testing for explanation by other factors; and (iv) only attributing results to inefficiency if other possible explanatory factors are insufficient to explain the divergence between that company and the other companies.

We would suggest a stepped process to set operating allowances based on normalised operating costs as follows:

- the input data should be normalised;
- it should be assumed that companies are roughly equally efficient unless robust evidence to the contrary is evident;
- a range of comparative analysis (including several techniques) should be conducted to investigate alternative explanations of any apparent inefficiency gap;
- a company's base costs should be adjusted for a company-specific efficiency adjustment only if the range of evidence supports that conclusion;
- for other companies, the normalised costs should be re-adjusted, where reversing the normalisation adjustments is legitimate;
- companies' forecasts of costs should be examined and any alternative view from Ofgem on future cost pressures should be justified; and then
- an aggregate industry factor for future efficiency gains should be applied.

We recall that throughout the price review process last year, Ofgem was at pains to assure companies that Ofgem will continue to use a range of techniques to assess efficiency and to project future costs. We therefore hope that this approach will be sustained over the coming months.

6.7 Mergers

We strongly support the consideration of merger effects in any cost assessment. Not all mergers are the same – notably DNO/DNO mergers are likely to have higher synergy cost savings than other mergers. It is clear from Ofgem's own work that mergers of DNO's release cost savings that are not available from other corporate transactions.

We have previously explained how the 14 company data can be adjusted to take account of the effect of mergers. Additionally Ofgem must look at 8 data points, reflecting the reality of the 8 management teams. Here too, we expect Ofgem to review the evidence and adopt an approach that best reflects the relative performance of the companies. We have already sent to Ofgem our analysis and evidence which indicates a possible convergence of the data if the existence of 8 rather than 14 management teams is considered. A robust analysis needs to take this perspective into account.

We agree that some merger benefits are available to all companies and should rightly be revealed through benchmarking. However a specific adjustment (to put all licensees on an even footing) is necessary unless all benchmarking is done on an '8 management team' basis.

6.8 RAV Roll forward

We see the debate on RAV roll forward as an important area for the demonstration of regulatory consistency by Ofgem. It would be helpful for DNOs to have an opportunity to see Ofgem's initial thinking in this area at some stage during the month of May. In this way we will be able to comment before the June initial proposals are formulated. We hope that Ofgem will be able to factor this into future plans.

7 Financial Issues

7.1 Financial Ring Fence

We note your proposal to strengthen the financial ring-fence.

We believe that a generic licence modification along the lines that Aquila accepted should not necessarily be seen as good precedent because of the particular circumstances in that case.

A licence modification that, under certain circumstances, cedes management control of dividend policy and asset transfers to a regulator, may be unhelpful to the view of the capital markets. For example, if as a result of **its** pricing actions Ofgem caused the loss of an investment grade credit rating, this would result in Ofgem being able to take some 'management' control and might undermine the confidence of the capital markets.

The natural effect of such a licence modification is that Ofgem should take upon itself an implicit responsibility to ensure that prices are set such that a regulated entity is able to finance its functions, i.e. that it would do nothing to damage credit ratings of the regulated entity. This is a similar obligation to that currently upon Ofwat.

We would expect Ofgem to confirm this implication to the capital markets as a condition of our acceptance of the licence modification.

7.2 Cost of Capital

In overview, we believe that the allowed cost of capital should be set at least at the top of your proposed "vanilla" range of 5.1% to 5.9% with a further allowance for embedded debt and the cost of debt transactions. We agree with Ofgem's use of a vanilla WACC in the post-tax building blocks to the price control. However, the allowance for tax costs needs to be consistent with the level of gearing assumed in the balance sheet of the DNO as part of any financeability test used to ensure that the price control can be appropriately funded.

Ofwat has made it clear on a number of occasions that the <u>bottom</u> of their range for the cost of capital in the current water price review will be 5.0% on a fully post-tax basis, equivalent to the top of the Ofgem range. However, although capex is higher in water, there are a number of reasons why risks, and hence the implied cost of capital, are higher in electricity distribution. In particular water has:

- an IDoK mechanism so that companies (or the regulator) can ask for changes to the price control between periodic reviews if there are material differences from regulatory price control projections in a number of specified items (e.g. construction prices); and
- a substantial effects clause so that major changes in circumstances can be reflected in new price limits between reviews.

Consequently, it is inconsistent that the whole of Ofgem's range is below the bottom of Ofwat's range for the cost of capital from 2005 to 2010.

The cost of capital needs to be set sufficiently high to enable companies to raise the capital required in the next quinquennium, in particular to fund distributed generation. Although we have not specifically argued for an equity premium to enable rights issues to succeed, it should be noted that:

- we have assumed successful rights issues in our FBBQ;
- the competition commission allowed BAA a 0.75% premium on their cost of equity to enable rights issues to succeed; and
- NERA, in its report for Water UK, includes a 0.3% premium to cover equity issuance costs.

The following sections reflect our views on specific components of the cost of capital.

7.2.1 Risk-free rate

Ofgem has assessed the range for the risk-free rate as 2.25% - 3%. The bottom of this range is far too low – lower than the bottom of the range set by any Competition Commission enquiry. Ofgem quotes the NERA assessment of the current risk-free rate as 2.6%, and 3.1% using historic time series. International evidence quoted by NERA shows the 2 year average yield to maturity for a range of American and French index-linked bonds is 2.93%. Our view is that the risk-free rate is between 2.5% and 3%.

7.2.2 Debt premium

We are comfortable with Ofgem's range for the debt premium provided that in addition allowance is made for transaction costs and embedded debt (see below).

7.2.3 Gearing

OXERA' s report for the ENA stresses the risk that choosing a gearing assumption above 50% may lead to an inappropriately low overall WACC and that this may threaten the financeability of investment and generate further incentives for companies to gear up. Furthermore, OXERA points out that:

- the CAA has acknowledged that there is no consistent academic evidence or normative model that predicts unequivocally the optimal capital structure; and
- given this and considering national and international evidence, gearing of 50% may be close to the norm.

We accord with OXERA's view. If a higher gearing level is chosen, then this implies both a higher cost of equity and a higher cost of debt and care must be taken to ensure consistency between these three parameters.

7.2.4 Equity risk premium

We believe that the equity risk premium is at or above the top of Ofgem's range. Evidence on market to asset ratios is presented below demonstrating that the cost of equity was set too low at the previous review. Ofgem should consider international evidence when setting the ERP as detailed in the NERA report for Water UK. In summary:

- Recent US decisions on ERP vary between 5.9% and 8.5%.
- In Australia, recent cases lie in the range 5% to 7%.
- The electricity regulator in the Netherlands in its guidelines for the period 2000 – 2003 said it "*considers it reasonable to fix the market risk premium between 4% and 7%.*

NERA presents further evidence in their report showing that the long-run historical average of the ERP over 15 countries over 100 years (in the study reported by Dimson, Marsh and Staunton in 2001) is 5% - 7%. Based on p/e ratios, forward-looking estimates of the ERP are also in the range of 5.6% - 6.9%.

Further evidence for a high equity risk premium can be obtained by using the dividend growth model (DGM) and we would strongly recommend that Ofgem continues to consider this model to validate its cost of capital. Ofgem's cost of capital appendix assesses the cost of equity using the dividend growth model as 6.3% to 7.6%, however, our analysis would suggest a higher level. In particular, this appendix suggests average dividend yields from a sample of companies to be 5.3% to 5.6%, but does not back up this evidence. The best evidence, in our view, is from the UK quoted water sector where the weighted average yield from January 2000 to February 2004 was 7.3%. Using Ofgem's suggestion of 1-2% growth, this implies a cost of equity of 8.3% to 9.3%, well above Ofgem's range. NERA's estimate of the cost of equity using the DGM is 9.7% (before equity issaunce cost of 0.3%).

Accordingly, our estimate for the equity risk premium is 5%.

7.2.5 Equity beta

Because of the lack of quoted companies, it is appropriate to consider the water sector as a comparator when assessing betas. NERA estimates asset betas for water companies as 0.35 based on the spot market over the past year, but at a time when market volatility was high. Their time series estimate over three to ten years which adjusts for the impact of abnormal events such as PR99 and for the abnormally high levels of market volatility is 0.5. The CC's most recent relevant assessments were for Sutton & East Surrey and for Mid Kent Water in September 2000. In both cases, the CC assumed 0.5 for asset betas. Accordingly, our assumption is an asset beta of 0.5 implying an equity beta of 1.0 at 50% gearing and 1.25 at 60% gearing.

7.2.6 Market to asset ratios (MARs)

Although there are no directly quoted UK DNOs, evidence on the cost of capital can be gleaned by reviewing evidence from the water sector. NERA has calculated that the average MAR for the water sector from the outcome of the Competition Commission enquiries in 2000 to November 2003 has been 91%. As a result, NERA concludes that the cost of capital used by Ofwat in 1999 is likely to be around 0.8% lower than the true market WACC. It is reasonable to assume that all of this 0.8% was due to a low estimate of the cost of equity, since the measurement of the cost of debt is fairly straightforward. Based on 50% gearing, the evidence that the cost of capital was 0.8% too low implies that the cost of equity, set at 6.2% was 1.6% too low.

The low MAR values are borne out by the Competition Commission's report on Mid Kent Water which quoted MARs for WaSCs in April 2000 averaging 76%. Insufficient allowed cost of equity is also evidenced by the partial exit of equity in both water and distribution evidenced by the move to thin equity and no equity structures. Allowed cost of equity, and hence dividend payments, must be set sufficiently high to avoid further exit of equity and hence increases in gearing in the DNOs.

Furthermore, the seven water company purchases since November 2000 have all been estimated by NERA to be below RCV. This gives further weight to our belief that Ofwat's 6.2% allowed cost of equity in 1999 significantly underestimates the actual cost of equity in both water and electricity. The adjustment of 1.6% quoted above to give a cost of equity of 7.8% is consistent with our assumption of a risk-free rate of 2.5% - 3.0% and an ERP of 5%.

7.2.7 Embedded debt

It is essential that companies are allowed an embedded debt premium for any long term debt. In particular, UUE will have an average of £215m of embedded debt in the next quinquennium at an average of 8.81% from fixed rates bonds taken out many years ago. This will require an embedded debt premium of approximately 0.6% to fully finance (see FBPQ answer to question 15 for further details).

OXERA states "it is considered that the most appropriate manner for dealing with embedded debt is through a company specific adjustment". NERA's report for EDF energy also supports company-specific allowances for embedded debt:

"Failure to allow for the costs of embedded debt would be equivalent to denying DNOs the chance to recover their sunk costs, and may reduce incentives for DNOs to make efficient long-term financing decisions in the future."

7.2.8 Transaction costs

NERA in its report for EDF energy (and in its UK Water report) includes 0.10% - 0.15% for transaction costs. In addition, UUE maintains funding headroom of 12-18 months to avoid periods of high volatility in the debt market. This adds a further 0.05% to the cost of debt. In total, as described in detail in our answer to question 13 in the FBPQ, UUE incurs 0.15% of costs associated with raising finance and maintaining headroom and this needs to be recompensed within the overall allowed cost of capital. Consequently, the cost of capital should allow for 0.75% (0.6% + 0.15%) additional debt costs over and above the ongoing baseline cost of debt.

7.2.9 Credit rating

It is important that Ofgem ensures that companies have an appropriate credit rating to enable them to fully finance their functions. In the next five years the additional expenditure for distributed generation makes the sector more risky and means that companies will potentially have to raise a mixture of debt and equity to finance themselves. Allowed revenue needs to be set at a level that meets Ofgem's target of "comfortably within investment grade". This is commensurate with a credit rating of A3 as a minimum as detailed in our FBPQ responses. In summary:

- It is appropriate to raise long term funding to match asset lives, and long term debt increases certainty, reduces refinancing risk and allows access to a broader investment base. However, there is a significant reduction in debt availability when credit ratings drop below A2, in particular long-term debt.
- There needs to be a sufficient shock barrier above investment grade if an industry event affects the sector – for example the utility downgrades seen when Hyder hit problems in 2000.
- Because the UK market sometimes prices inefficiently, UUE requires access to international markets. However, swaps are then required and these are limited and costly below A3 grade.
- Committed, undrawn bank credit facilities to fund our 12-18 months headroom become increasingly difficult to source below A3 grade.

In summary, a credit rating comfortably within A3c grade is required to ensure that UUE, with its large capital expenditure programme, can fully finance its functions through to 2010. Ofgem will need a dialogue with the credit rating agencies to ensure that the financial indicators for companies (before any balance sheet adjustments that Ofgem might use) are sufficient to achieve target ratings.

7.3 Treatment of Pension Costs

We remain hopeful that the differences between companies and Ofgem can be resolved. There are encouraging signs in your paper of the gap narrowing. However we do need to understand the timetable and process for incorporating more up to date estimates of the relevant parameters into the price control calculations.

7.3.1 Allocation between price controlled and non-price controlled activities

The numerical analysis that has been completed since the last consultation has helped to clarify the issues that need to be resolved. This has been a helpful step, and we are pleased that Ofgem recognise the need for pragmatism where actual data does not exist for the more distant past.

7.3.2 Over or under provision

We support the decision to abandon detailed attempts to reconcile actual spend in the current period with any notional allowances. Our earlier work has suggested that any imbalance would be modest and more than covered by the uncertainty surrounded by any definition of 'allowance'.

7.3.3 Early Retirement Deficiency Costs

As explained in John Roberts' letter of 17 March, we are disappointed by the stance adopted by Ofgem. In our view, the actions of DNOs in using pension surplus to support early retirement have been of long term benefit to customers. The reductions in costs achieved through early retirement have been reflected in the benchmarks used to derive subsequent revenue levels. It would not be appropriate now to expect companies to make good pension funds, when the benefits have already been realised for customers.