United Utilities Electricity PLC
Consultation Response

Electricity Distribution Price Control Review

Response to Ofgem's September Update

October 2004

Contents

1 Executive Summary

In this document we provide further comments on your Distribution Price Control Review. Our focus is on the issues raised in the September Update, but we also cover, in the final section, other outstanding areas that need to be addressed before the Final Proposals can be completed.

We recognise the progress that has been made in the September Update in a number of areas but remain concerned that there is still a very substantial gap between our expenditure requirements, as described in our business plan, and the revenue implied by your proposals. In summary the key points made in this response are:

- **operating cost assessment (including fault repairs)** – where your proposals fall far short of our business plan estimates;
- **cost of capital** – which needs to be increased significantly to encourage new equity finance to support future investment plans;
- **capital expenditure** – where elements of our work programme have not yet been included, and non-operational expenditure is being depreciated over excessive lives;
- **pensions** – where specific features of our pension scheme remain still to be addressed;
- **quality of supply** – where targets have been set without regard to the costs of delivering current levels of service; and
- **metering** – where we still await a full set of initial proposals.

In addition, the work on licence modifications is already beginning to throw up examples of policy detail that still need to be resolved.

All of this suggests that there is a busy period ahead if complete and acceptable final proposals are to be published in November. The work on operating costs and the cost of capital and the most urgent, since it is here that the most significant difference in view between your position as described in the September Update and the content of our response is to be found.

2 Metering

2.1 Incomplete Proposals

It is disappointing that we have not yet seen complete initial proposals for metering. Whilst this document does provide more detail, there are still significant areas of the metering price controls undefined.

As the ENA letter to David Gray dated 10th September set out, it is unacceptable for the final proposals to contain the first complete set of metering price control proposals from Ofgem. It is essential therefore that work is concluded and communicated to DNOs by the end of October to enable review and comment prior to the final publication. We expect that the Metering Working Group will provide a suitable forum to resolve most of the areas of detail that remain outstanding. There has already been additional data exchange to help to improve the approach proposed by Ofgem.

2.2 Prepayment Meter Stranding

We are pleased that Ofgem has recognised that some DNOs may be exposed to unavoidable losses as suppliers move towards national standardisation of prepayment technology. However, the proposal set out in the September Update document for mitigating this risk simply does not work as:

- raising prices increases rather than decreases the risk of premature replacement;
- suppliers who remain with the existing technology face a disproportionate share of the costs increasing the incentive on all suppliers to switch sooner to avoid being caught out by this effect; and
- price increases will exacerbate the social concerns over prepayment metering.

It is possible to achieve a degree of protection through an adjustment to the price control, however, this can only be done by adjusting the depreciated replacement cost calculation. United Utilities is one of only two DNOs which uses the smartcard prepayment meter. The average remaining working life assumption used in the DRC calculation for United Utilities was 5.7 years.

Smartcard meters are due to be phased out as suppliers are standardising on smartkey meters. Consequently the manufacturer of smartcard meters (Siemens) wants to cease production and is planning to withdraw technical support for this meter. BGT, who have around 30% of the prepayment meters on our network, have already given notice of their intention to use smartkey whenever a new prepayment device is required in one of their customers' premises. We understand that Powergen, who have around 60% of the prepayment customers, intend to follow shortly. This has a fundamental effect on the remaining working lives of the smartcard meters as we lose the ability to recycle meters and suppliers drive towards a rapid switch over of technology with resultant savings in their infrastructure costs. We estimate this will reduce the remaining working life of these meters by 50%. This would result in a DRC valuation of these meters of £4.05m.

Amending the DRC calculation with the current (shortened) meter life in this manner would address the risk though not eliminate it. This approach would also share the impact of the technology change equitably across all suppliers.

An alternate market based approach for dealing with early return of leased or rented assets is to levy a termination charge. There are numerous examples of this from car lease agreements to Sky TV deals. This is normal commercial practice and is not a barrier to competition in a wide range of markets. In the absence of an adequate protection mechanism within the price control then this is the only alternative that can be adopted.

2.3 MOp Restructuring Costs

Throughout the price control review we have consistently explained the effect of the dominant supplier in a DNO area choosing, through the competitive market, an alternative provider of MOp services. There will be inevitable restructuring costs for the DNO, in terms of the workforce, the associated IT and back office support used to deliver the current licence obligations. This risk is significantly greater in DNOs, like UU, where the dominant supplier is not part of the same corporate group. In addition, the cost of providing a meter operation service to the remaining suppliers (once the dominant supplier has moved) will become prohibitively expensive.

Neither the Initial Proposals nor the September Update comment directly on this issue. The DNOs only alternative is therefore to seek to recover these costs from the remaining suppliers.

By not addressing this issue within the price control review, we anticipate that further action and involvement by Ofgem will be required when the implications of this approach are felt within the competitive supply market.

We remain of the opinion that the proposed form of the MOp price control is overly complex and that a tariff cap approach would be simpler to manage and achieve the same objectives. To accurately use regression tools to derive appropriate drivers for a revenue control would require a far greater number of data points than are available. We believe the true cost drivers of meter operation are a combination of factors related to the meter population and to suppliers' policies in servicing their customer base.

3 Quality of Service and other outputs

3.1 Introduction

We remain very disappointed with the approach to quality of supply set out in this Update paper. It has been a central theme of our previous correspondence that Ofgem should focus on the value for money derived by customers. This represents a combination of price and service levels. These two elements have still not been brought together satisfactorily within the review process.

Previously we have focussed on the approach to target setting, in particular the CML targets where we still believe your methodology is fundamentally flawed. We remain unhappy with this methodology, but given your obduracy on this issue we have now turned our focus to looking at whether the proposed targets are actually achievable.

We have maintained our view throughout the process that the existing cost of existing service levels must be considered before either future targets or cost allowances can be set. We believe that one of these factors needs to be established before the other can be determined, and agree that it is not in customers' best interests for our existing high service levels to be reduced. However, if existing service levels are to be maintained, then cost allowances must recognise the continuing cost of providing service at these levels.

We have presented you with detailed analysis of the incremental costs associated with our service levels, but these have not yet been recognised in your methodology for setting allowances. We can still see no evidence of a link between current service and base costs within your work, and we remain baffled that a company that has consistently been around the top of the value for money table should continue to be treated so harshly in setting opex cost allowances.

3.2 Interruption Targets

We acknowledge the minor corrections you have made to the target setting process. Whilst we are comfortable with the approach to setting CI targets, we are still unhappy with your approach to setting CML targets. It is inappropriate for you to ignore the obvious inverse relationship between CI and CML/CI, on the basis that one company out of 14 is different, particularly, as your document acknowledges, when the inverse relationship is most apparent on networks with a high underground content. It is these networks where repairing of faults takes longer due to the technicalities of repairing underground cables versus overhead lines.

We cannot see how you can be so confident that the approach is reasonable when at the same time you acknowledge that there is a relationship at the aggregate level, especially given that the characteristics of your reference company are so different to other types of network. Like most other DNOs we have submitted a number of alternative approaches to setting CML targets and remain dissatisfied that these are still excluded from your approach.

3.3 Cost allowances

We acknowledge the adjustments that have been made to gap closure allowances for restoration costs, however these are only adequate if considered as top up allowances to existing expenditure. Here we continue to be perplexed by the inconsistency of your approach. You have established a linkage between cost allowances and performance when it comes to moving from existing performance to future targeted performance. However, in setting base cost allowances for opex the linkage between existing costs and existing performance has been totally ignored. Not only is this inconsistent, it ignores a primary obligation to ensure we are adequately funded to carry out our activities at a service level that you have determined.

For the process to be consistent, at the very least, it must recognise in some way the marginal cost of higher existing service levels and ensure these costs are included in opex allowances.

We also remain unhappy that only two licensees receive a substantial additional allowance for accepting a CML target tougher than their 2020 benchmark. Previously it has been assumed that the CI element of performance is strongly linked to capex, but we have submitted extensive data, which demonstrates that this is by no means the whole case. The additional opex allowance should also be extended to those companies who accept a CI target tougher than their 2020 benchmark. This would, at least in part, recognise the marginal additional cost of service performance.

3.4 Incentive Rates

We remain disappointed that the incentive rates do not match customers' willingness to pay more closely. We have a particular problem with the CML incentive rate when considered alongside the target that has been set for us. The problem is that with such a low target of 53 CML the incentive rate has no effect on us after we reduce by another 4.5 CML as the cost of improvements and IIS rewards curves cross over. The max reward is 30% of target, which is 18 CML. Clearly this offers us no opportunity for upside whilst the full downside penalty remains. In order that the incentive has an effect, the incentive rates must be increased by narrowing the performance band.

3.5 Interruption Audits

The proposed revisions to the audit process represent a sensible step forward to realising a more streamlined process.

3.6 Exceptional Events

Our worst event on record was in 1997 with 230,000 customers affected, which equates to 30% of exposed customers. On this basis we propose that the very large event threshold is set at 30%. It would not seem unreasonable to set an "all bets are off" threshold at say 50% of exposed customers.

3.7 Treatment of other types of exceptional events

We welcome the clarity intended with these new arrangements, however we have some concerns over the mechanics of the proposals.

By definition, these events are truly exceptional and therefore the thresholds may be seen as reasonable. Where we have concerns is that the proposals only afford a limited amount of protection once the impact moves above the thresholds. Surely if these exceptional events, which are deemed to have been absolutely outside of the reasonable control of the DNO, occur, then it must be logical to remove their full impact from performance in the IIS.

Whilst the proposal seeks to clarify and firm up arrangements, the previous arrangements allowed DNOs to make individual representations for exclusion each time one of these events happened. We are not sure how often this actually happened but the new arrangements appear to remove the flexibility for you to deem that all reasonable steps had been taken and the full extent of CI and CML excluded.

Additionally, we suffer from a large number of vandalism and organised crime incidents, which tend to be on distribution substations where CI and CML impact on an individual basis are not significant but in aggregatebecome significant. Despite additional security measures and police initiatives we are still unable to prevent this happening. We believe that these events are also exceptional, however this proposal does not contain provisions to address this type of issue. We propose that you include flexibility in the arrangements for this type of situation to be considered on an individual case by case basis.

4 Cost Assessment

4.1 Introduction

We are extremely disappointed with your work on cost assessment, which fails to make reasonable predictions of our cost requirements. Your methodology may work for most companies, but we have identified specific reasons why the comparative efficiency score for UUE is inappropriate. The impact of this is further compounded by unrealistic estimates of the scope for future efficiency gains. It is essential that the flaws in the cost assessment are rectified before Final Proposals are made. We will comment against the headings of your paper, but you should also refer to the letters sent on 25 May, 19 August, 27 August, 31 August and 3 September which set out our proposals on how to rectify the weaknesses of your analysis.

4.2 Operating costs and faults

4.2.1 Normalisation

We recognise the efforts your staff have made to produce a comparable dataset for 2002/3. Our remaining concerns are more about the need for additional adjustments than the scale of adjustments already made.

4.2.2 Cost function and composite scale variable

A single composite variable cannot be expected to accurately specify all companies' costs. The discussions on CSV have been unsatisfactory. It has never been clear whether the objective was to develop a model with the best explanatory powers or one that appeared plausible to the lay observer. The workshop you arranged did not address this question and fell into a predictable pattern of arguments for self interest. We would note that the 'arbitrary' equal weighting of the three components of CSV gives a better statistical fit than any of the alternatives, which were apparently based on different companies' views of practical realities!

4.2.3 Regional factors

We have always argued that regional factors apply to differing degrees to all companies. There is an issue only because the basic model is too simplistic. We think there are other factors that should be given greater priority if the objective is to improve the overall model outcomes. Our proposals on:

- Cost of Quality;
- Capital substitution; and
- DNO-DNO Mergers

have been documented elsewhere. It is perfectly possible to adjust for these factors and produce a more robust efficiency score.

4.2.4 Establishing a benchmark

The discussion on this issue is couched in terms of the impact on customers in the short term. It seems to us that the more appropriate considerations relate to incentives – and the need to encourage further improvements in efficiency in future years – and risk – which will be reflected in the cost of capital. While the allowed cost of capital is based on the sector average, it cannot be right to allow this return only for companies that achieve some superior benchmark, whether it be frontier or upper quartile. We have demonstrated that we are above average in the efficiency league table, and that our shareholders should be able to expect an above average return.

4.2.5 Glidepath

We find the arguments against a glidepath unconvincing. They are based on a conviction that the efficiency analysis is beyond challenge, and that substantial instant adjustments to performance are achievable. We continue to hope that the cost assessment work will be modified to produce a more realistic spread of 'efficiency scores', so that the scale of this issue will diminish. However, there is another inconsistency between your work on quality of supply and on cost efficiency. If it is reasonable to allow companies time and money to improve service levels, why is it not equally appropriate to do the same for cost levels.

If we were expected to move to the level of costs implied by the September Update, there would inevitably be a cost in restructuring our operations to match the changed circumstances. The result would be significantly reduced performance against quality standards as well as an implementation bill of around £20m. The idea that such a substantial change could occur before 1 April 2005, even with finance for severance arrangements and reorganisation is unrealistic. Any shortfall of cost allowances against our FBPQ would therefore need to be managed by a glidepath.

4.2.6 Frontier Shift

It is pleasing to see that you have begun to take heed of company concerns over the aggressive nature of your proposed frontier shift. There are two issues to consider here. The first is the scope for future improvements in performance. We have submitted a critique of the work that you and CEPA have previously done and made a good case for sector performance to be equal to that embodied in RPI movements. The second issue is again incentives. If all of the anticipated benefit is captured in advance for customers, the rewards available to companies for improving performance will disappear. This is likely to have a damaging long term effect both by reducing management interest in efficiency and by undermining the business case for efficiency investments. Some split between carrot and stick would allow customers to reap some immediate benefits whilst leaving positive incentives for companies to innovate.

4.2.7 Total Cost Analysis

We have tried to persuade you to look more carefully at total costs, but what we now see is an approach that fails on two levels. There is still an understandable interest in opex analysis, but this could be easily adjusted to reflect differing rates of capital consumption. This would still be an analysis of opex and therefore provide a reasonable basis from which to assess future opex allowances, but it would have taken account of more of the reasons for variations in current opex. An alternative would have been to build a proper total cost model that simulates the whole life cost approach to infrastructure businesses that companies should be encouraged to pursue. We accept that such a tool does not yet exist and that this is a project that needs to be left for the next price control period. We must therefore ensure that any work that is labelled total cost is in fact an attempt to refine opex analysis by taking account of usage rates of the capital stock. Such an approach must be backward looking as it is intended to explain variations in base year opex. Your preferred approach fails on this count. In our view it is more valid to look at a long term view of capital usage rather than a short term view of capital spend. We have provided extensive analysis along these lines which we hope that you will now adopt. If you have found any problems with our analysis of a capital consumption adjustment, we would be happy to discuss this. Your failure so far to adopt our proposal has not been justified.

4.2.8 Data Envelopment analysis

We see little value in DEA unless the basic data set has first been refined. As we have argued previously the cost base must be adjusted to reflect variations in companies' circumstances (on quality, capital usage and mergers) before such analysis is attempted.

4.2.9 Vegetation, exceptional events and quality improvement

We find it puzzling that every company now gets an allowance for vegetation management apart from LPN (who have a fully underground network) and UU (which has about a quarter of its network overhead and has no shortage of trees in the rural areas where that overhead system exists).

4.2.10 Comparison with 2003/4 analysis

Your discussion of the 2003/4 data ignores the lessons that emerge for forecasting future costs. The model that you have used for projecting 'efficient opex' implies that all companies can reach the (upper quartile) benchmark by 1 April 2005. There is no evidence of convergence in the data for 2003/4 making it even less likely that your forecasts for 2005/6 are achievable. In addition, the 2.6% real increase in average costs does not sit well with your assumption of a 1.5% pa real improvement in productivity. Your estimates of future costs should be reconsidered in the light of the evidence presented for 2003/4.

4.2.11 Mergers

We have provided substantial evidence of the additional scope for cost reductions that arise uniquely from DNO-DNO merger. If your purpose is (as it should be) to consider the relative efficiency of companies, your analysis must take account of the actual circumstances faced by each company. For this reason it is inappropriate to base 'efficiency scores' on the output of a model that ignores the ownership grouping of the companies. Your previous merger policy acknowledged that benefits were likely to build over the first five years after a merger. This suggests that the time since a merger happened should be built into the comparative analysis. We have proposed a mechanism for this and have also suggested an alternative approach which would allow future allowances to be adjusted for cost savings not within the scope of individual licensees. Your suggestion (para 4.47) that a 'glidepath' be constructed is consistent with our first suggestion.

4.2.12 Rates

We are pleased to receive confirmation that network rates will, in future, be treated as a pass through item. This should be recognised in your modelling of P0 and X values, which should ignore the effect of movements in rates cost, just as is the case for NGC charges.

4.2.13 Dealing with uncertainties

We welcome the progress being made to protect companies from the new uncertainties arising from obligations under the Traffic Management Act and ESQCR. We have previously highlighted a third area of significant risk. This relates to BT's proposed move to IP technology and the withdrawal of support for current point-to-point dedicated lines for protection, Telecontrol and PMR. This could happen as early as 2006.

We understand your reluctance to give additional allowances now for costs that may not materialise. However, it seems perfectly reasonable to recognise now the likelihood of such costs arising and the need for a recovery mechanism if they do.

4.2.14 Conclusion

Your work on opex and faults is the most worrying part of the price control review. Your model still fails to present an accurate position of our relative performance and will not generate acceptable future cost allowances without significant modification. We have presented detailed proposals to overcome the weaknesses in your modelling, which act disproportionately on United Utilities. We need urgent confirmation that this is an area where substantial change will occur before you publish Final Proposals.

4.3 Capital Costs

4.3.1 Base case capex

You have continued to ignore the adjustment that we made to our base case submission in January. This involved the addition of work at Whitegate GSP to replace switchgear based on a substantial engineering investigation undertaken in December 2003. We had understood that our plans had been scrutinised by PB Power and the need for the work to be done had been confirmed by them. This increase in base capex has still not appeared in your proposals. The final proposals should rectify this omission.

4.3.2 Resilience and worst served consumers

We understand your proposals to confirm that the additional capex identified in the sensitivity analysis you requested in January is not considered necessary.

4.3.3 ESQCR

We have written to Martin Crouch recently on this subject. We are concerned that only one aspect of ESQCR has been debated and that this has led to the (mistaken) conclusion that no additional capex will be needed before 2008. We have also identified additional opex that will arise from new reporting requirements. We hope that the issues raised in our letter will be addressed before the Final Proposals are presented.

4.3.4 Fluid filled cables

We note with some concern that you are not intending to clarify the position on fluid-filled cables until after publication of the Final Proposals. We have responded to your requests for details on our fluid-filled cable population, operation and proposed replacement, and look forward to working with you to develop a consistent treatment of these assets across the industry. We need clarification that the result is discrete treatment of this category of asset replacement and hence that it does not form part of the capex allowances quoted for each company in the September Update.

4.3.5 Sliding scale mechanism

Our position on incentives is likely to be driven by our concerns that your opex allowances are inadequate.

We support incentive-based regulation and have consistently advocated the principle that the price review should seek to establish a framework of incentives that encourage appropriate and desirable behaviour from companies. Therefore, we support the sliding scale mechanism and the principles of encouraging companies to forecast accurately and ensuring they do not gain by inflating forecasts.

We recognise the data consistency issues that you have struggled with during this price control review. We are still likely to be detrimentally affected by inconsistencies in cost reporting, despite the considerable normalisation effort undertaken by your staff. We understand that we were the first company to provide evidence of the seriousness of this issue, back in 2002. We remain sympathetic to the argument that companies need to be incentivised to develop and implement improved cost reporting regulations. However, we have concerns about the effect on efficiency incentives, and therefore on customers, that results from equalising incentives to the lowest level available.

In principle, we believe that opex incentives should be increased or at least maintained at current levels to reflect the growing difficulty in realising improvements in operating efficiency. Future efficiency initiatives are likely to require increasing levels of investment. Reducing incentives is likely to undermine the viability of important projects, and therefore slow the rate of future innovation.

However, we can also see that from a practical perspective it may be attractive to be able to share the burden of cost over-runs with customers in a symmetrical incentive scheme. This becomes more valuable given the inadequate nature of your latest version of opex allowances. While we have the threat of unattainable cost allowances hanging over us, we find it difficult to use principles to guide our response to your proposed incentive framework. Instead we are compelled to consider the practical realities of our situation.

Therefore, when considering the three options for incentive mechanisms proposed we favour the first option of an immediate annual revenue adjustment. We believe this option has a number of advantages:

1. The new incentive arrangements will be unambiguously described in the detail of the licence, adding weight to the incentive effect of the reduction in opex rewards in the cost reporting debate.

2. A clear procedure for the disapplication of such an incentive mechanism could also be described in the licence – making it clearer to companies that incentives would be increased once you were satisfied that reporting requirements were effectively implemented.

3. The period of operation under reduced incentive arrangements would be minimised – minimising also the detrimental effects of reduced incentives on customers.

4. The regulatory uncertainty and risk associated with a "clawback" debate at the next price control review would be reduced.

5. DNOs would be able to share some of the overspend against inadequate allowances with customers in the first few years of the price control, where the likelihood of such overspends are greatest.

The key disadvantage that we see in this approach is the possible creation of a perverse incentive to frustrate the cost reporting project until a company has implemented sufficient change to bring its operating strategy, practices, performance and costs down to the low costs (and correspondingly low quality) benchmarks you may set. This is clearly a situation that you can address by ensuring that companies receive adequate cost allowances to enable them to maintain quality and effective operating practices.

5 Financial Issues

5.1 Pensions

We are pleased that you have covered most of the previous issues we have raised on pensions. However, there remain four outstanding issues to be resolved:

- The calculation in the September Update incorrectly deducts 1/13th from the deficit assuming this is recovered through pension contributions in 2004/5. This is not the case. Following normal pension industry practice, the deficit recovery will only apply from 2005/6 when the 2004/5 actuarial assessment can be implemented. We are assuming that this adjustment will be corrected in the Final Proposals.
- We understand that the assumption for normal pension contributions will be updated in the Final Proposals on the basis of the latest actuarial valuation. These figures have not been amended since the June proposals.
- Under FRS15, labour costs can only be capitalised when they are directly attributable to bringing a fixed asset into working condition for its intended use. The contributions to fund the deficit are not directly attributable to building an asset in the year the contribution is being made. Therefore to conform to this accounting standard companies will be required to expense any recovery of pension deficit. Further, prior period adjustments are limited to changes in accounting policy or corrections to fundamental errors. The recovery of the deficit does not fall into either of these categories, since this relates to new information on mortality rates and the market performance of the funds. This means that only the normal pension contribution can be split between expensed and capex. The contribution relating to the deficit recovery must be expensed.
- The pension assumptions in the September Update omit UUPS from the calculations. Details of this scheme have been provided in our FBPQ and subsequent pension submissions. An allowance needs to be included for this pension scheme in the final proposals.

5.2 Tax

Subject to our comments below we welcome the amendments to your approach to calculating tax in the September Update and believe that the revised position is now far more closely aligned with the actual forecast tax liabilities.

As referred to in previous correspondence we note that there is no allowance in the September Update for the tax planning adopted by UU on the abolition of ACT. We believe an adjustment should be made to the opening tax pools to ensure this issue is correctly treated in the price control.

In our FBPQ we assumed an injection of sufficient equity from the rights issue so that financial indicators would be maintained at the appropriate level. This new equity needs to be taken into account in the Final Proposals when considering the actual level of gearing used in the tax computation. The impact of this equity injection should take gearing to Ofgem's theoretical level assumed in the cost of capital at the beginning of the control period. This will ensure indicators are maintained at a level that matches UUE's funding requirements. It should be noted that UUE does not guarantee any debt outside the regulated business. UUE's tax allowance therefore needs to remain based on a notional gearing of 60%.

It will be in the best interests of customers, the regulator and the industry if you adopt a simple approach to calculating the incentive mechanism for tax. This needs to ensure that the process is not overly complicated and the reporting arrangements are as simple as possible to implement.

5.3 Regulatory Asset Value

We welcome your approach to rolling forward the RAV in the September Update and believe this now correctly accounts for differences between companies on capitalisation policy and restates the RAV on a consistent basis with the methodology supporting the 1999 review for the 2000-2005 period.

5.4 Financial Indicators

We note your exclusion of metering activities from the financeability test. This test should be applied to all activities undertaken by the distribution businesses. Although it would be preferable to include metering costs and revenues in the assessment, we agree that this is not likely to have a material impact on the overall level of indicators. However it is important to recognise the additional risk that shareholders face as competition threatens to reduce metering revenues substantially.

It is necessary to consider the trend in indicators up to and beyond 2010 to ensure that appropriate funding is provided in the new control, thereby allowing us to finance our plan and meet the criteria used by the rating agencies. There is no reference in the September Update as to how Ofgem has assessed the absolute level and trend in indicators over these periods.

We have tested Ofgem's financial model using the level of opex we need to spend. All other assumptions have been left unchanged, including dividends and the cost of capital. This shows financial indicators falling well below Ofgem's stated assumption of a credit rating comfortably above investment grade.

5.5 Cost of Capital

Compelling evidence has been presented to you that the cost of capital assumption should be increased to the top of the range in the March consultation (5.9% on a vanilla WACC basis). This evidence has mainly been presented by the industry through the ENA, supported by independent consultants' reports. Evidence has also been cited by Ofwat in the draft determinations for the water companies that investors believe that electricity distribution companies are on a par with, or more risky than, water companies. Water companies have the safeguard of an IDOK mechanism and a 'shipwreck clause' in their licence. A cost of capital figure below the top of your range is not adequate to enable us to finance the activities of the regulated distribution business.

We are unique among DNO owners in that we also own a water company and are part-way through a rights issue. We therefore have a direct interest in developments on the water price review.

Your position on the cost of capital contrasts markedly with Ofwat, in particular on the cost of equity. Ofgem's assumed return on equity of 7.25% compares with an Ofwat figure of 8.15%. We are in a unique position to judge investor sentiment in relation to its regulated water and electricity businesses and determine where it is best to allocate new equity. Significantly higher returns are now available in water, following Ofwat's draft determinations. In addition higher returns are available in other European Utilities. The capital markets are likely to move quickly to address this relative imbalance, placing greater risk on the availability of new investment in electricity distribution. The consequence of setting allowed returns too low would be that appropriate funding for electricity businesses would either not be available or would become excessively expensive. This is likely to result in a further exit of equity from the UK electricity sector over the next 5 years, as companies replace inadequately funded equity with expensive debt.

What matters to investors are the actual rates of return, which take account of the benefits of anticipated out-performance and the consequences of under-performance. Unlike other regulators, you are now applying too low a cost of capital at the same time as reducing the opportunities and incentives for out performance, which is reducing expected actual rates of return.

Setting the gearing assumption in the cost of capital assessment at 60% assumes that where a company's actual gearing is higher, equity is available to improve the financial position. The validity of this clearly depends on the appropriateness of the allowed cost of equity and as such you need to send the right signals to the markets and be satisfied that the cost of equity is set at the appropriate level to attract new equity capital.

The market views UU's shares as an income stock and UU's current dividend yield of 7.8% provides real world evidence on the cost of equity and contrasts with the 5% figure used in your modelling. We used this market evidence in our assessment of the post-tax cost of equity of 7.9% in our FBPQ.

5.6 Non Operational Capex

We are concerned that you have introduced a change in policy with regard to the treatment of non-operational expenditure. This change has not been referred to in any consultations to date. We believed there was a commitment from you that non-operational capital expenditure would be included in the RAV from 2005 and be given a life of 5 years. Therefore instead of being funded as opex (as was the case prior to 2005) this expenditure would be funded over a 5-year period. Although this change was cash adverse for companies, we agreed that this was the most appropriate treatment if this expenditure was to be included in the RAV.

Your financial model was further developed to include a facility to roll forward a separate RAV for non-operational expenditure under the assumption that this would have a different depreciation life from other RAV additions. Having agreed this principle, we find that the September Update treats non-operational expenditure in the same way as all other capex entering the RAV and depreciates this expenditure using a 20-year life. This does not align with your stated policy or with the practical depreciation lives of most non-operational assets. We hope that you will reconsider this change in policy.

6 Other Issues

6.1 Introduction

There a number of other issues that have been raised in the Price Control Review that do not appear in the September Update. For completeness, we will set out in this section our views on those issues where a satisfactory conclusion has not yet been confirmed.

6.2 Distributed generation

We have accepted your broad approach to distributed generation and recognize that the aim is to encourage efficiency in delivering specific connections, rather than incentives to improve the opportunities for renewable generation and CHP. With this in mind, our remaining comments relate to the detail that you have now described to achieve your objective. These are being debated within the Licence Modification workstream, but our comments are repeated here for completeness.

6.2.1 High Cost Projects

We have suggested that:

- The proposed £200/kW cap should be reset to £120/kW, for consistency with the incentive scheme parameters
- The generator should pay all costs above the level of the £120/kW cap (with no deminimis) as a capital contribution
- The project should be treated under the incentive scheme as costing £120/kW
- This removes the need for the C2a term in the RIG and Licence algebra, simplifying the arrangements and reducing the possibility of the seemingly perverse situation where the pass-through capex becomes negative for individual projects (where $C2a + C2b > 0.8(C2a + C2b + C3)$ in Ofgem's Figure 1).

We regard this as a risk issue rather than one of cost – although we believe that the implementation of an individual cap on high cost schemes would have negligible effect on overall DG forecast costs, it would be of significant help in making the incentive scheme acceptable.

6.2.2 Network Unavailability Rebate

We believe that this should be more closely aligned to Guaranteed Standards for demand customers, in particular for LV and HV connected customers, and that microgeneration should be excluded from any additional network access penalty arrangements.

6.2.3 Profiling of pass-through revenue and calculation of the rate of return

We have recommended a RAB based approach for calculating GDUOS, for greater consistency with demand pricing.

We await the draft licence conditions showing the calculations for:

- confirmation that revenue shortfalls from demand or generation will be merged and covered in post 2010 price controls;
- transfer of costs from generation to demand; and
- rate of return for the purposes of the cap and collar.

With regard to the definition of incentivised DG capacity, we believe that it is important that this should include capacity connected via third party networks.

6.2.4 RPZ

We do not believe that it is necessary to restrict RPZ to sites with new generation. It would be appropriate for the definition of RPZ capacity to be capable of some flexibility, depending on the circumstances of an RPZ project, for example by allowing for approval by you on a scheme by scheme basis. We believe that it is possible to incentivize RPZ on an additional-generated MWh basis for existing generation, and we would be pleased to share our thoughts on this with you before the licence drafting is finalized.

6.3 IT to support Structure of Charges project

The regulatory impact assessment which formed part of Ofgem's June 2003 SOEDC consultation made reference to the costs which DNOs might face in implementing Ofgem’s proposals. These were estimated at £0.5 - £1m for relatively modest changes to existing IT systems sufficient to implement adjustments to charging methodologies for all customers, including a simple generator UOS charge, through to £3 - £4m per DNO for more complex development such as would be required to support a more complex generator UOS charge. The RIA also says that you would expect consumers to pay a significant proportion of these costs via UOS charges.

There is no evidence that any costs have been allowed in the price review proposals published to date and we expect this oversight to be addressed in the Final Proposals. It should be made clear what proportion of new system costs would be borne by generators, via GDUoS, with the remaining sum to be incorporated in price controlled DUoS charges.