David Gray
Managing Director Networks
Office of Gas and Electricity Markets
9 Millbank
London
SW1P 3GE

Central Networks
Pegasus Business Park
Castle Donington
Derbyshire
United Kingdom
DE74 2TU
central-networks.co.uk

Bob Taylor
T
F
bob.taylor
@central-networks.co.uk

14 May 2004

Distribution Price Control Review Policy Paper

Dear David,

This is the response of Central Networks to the Distribution Price Control Review Policy Paper. This letter focuses on the key issues that we believe still need to be addressed; our detailed comments on the document are included in the attachment.

The Business Plan submissions of both our licensed distributors comprise detailed and rigorous cases for necessary increases in the level of investment. We are determined to manage our network asset risk in an efficient and planned way, but it should be noted that, even with the increased investment, average asset lives will be reduced from 130 years to approximately 100 years.

Our plans reflect the need to replace assets, whose condition is in decline, and hence prevent the deterioration of the existing quality of electricity supply to customers. We therefore welcome the sentiments of the policy paper, bilateral meetings held with Ofgem and industry workshops, where there has been recognition of both the need for and Ofgem's commitment to creating the right climate for increasing levels of sustained investment.

In support of this there are a number of policy areas that we wish to raise in this letter that are particularly important to us.

Financing the Investment Programme
There are significant risks attached to the delivery of large infrastructure projects, and we believe it is vital that a mixture of debt and equity is used to finance the delivery of the investment programme. This would encourage management to take appropriate risks that lead to innovative cost reduction solutions, which a highly geared structure would tend to avoid.

Central Networks East plc
No 2366923

Central Networks West plc
No 3600574

Central Networks Services Limited
No 3600545

Registered in England and Wales

Registered Office:
Westwood Way
Westwood Business Park
Coventry, CV4 8LG

Maintaining an appropriate level of equity to finance the investment programme will require Ofgem to set a sufficient rate of return, especially since we are competing in a global market for capital. Whilst we welcome the beginning of the necessary debate on the initial cost of capital range, we believe that the capital markets will focus on real world factors such as the long term increase in levels of investment, cash negativity, financeability ratios, the potentially reducing opportunities to outperform the price control as well as comparative rates in other sectors such as water. It follows that if out-performance opportunities are reduced, which the policy paper implies, then the cost of capital should be set at a higher range than published in the policy paper.

Ofwat has stated on numerous occasions that the bottom of its cost of capital range for 2005-10 will not be less than 5%, using a post-tax debt, post-tax equity basis. This is equivalent to the top-end range of the Vanilla WACC reported in the policy paper. It is worth noting that Ofwat has set this floor despite the fact that the risks are probably lower in water, given the Interim Determination mechanisms that are in place for dealing with uncertainty, but which currently do not exist in electricity. Given this and our own work on longer term funding requirements, we would therefore expect Ofgem to set a cost of capital that is at least 5.9% using a Vanilla WACC. This is necessary if the markets are to be persuaded to support the investment programme and we are to avoid ever-increasing debt and gearing levels.

Delivering The Investment Programme
We have fully invested our allowances for DPCR3 and we fully intend to deliver the capex proposals we have submitted for DPCR4.

We understand though that Ofgem has concerns about the potential for DNOs to defer capital investment, and in the attached appendix we include proposals on how we might demonstrate our commitment to delivery. We hope that you will find the proposals constructive.

Efficiency Incentives On The Investment Programme
Whilst we understand Ofgem's concerns in relation to the potential distortions that incentives may cause, we would stress that, in an environment of increasing investment, it remains important to ensure that incentives are appropriate for delivering programmes as cost effectively and innovatively as possible. Otherwise there is a real danger of new costs creeping into the business, thereby removing some of the benefits enjoyed by customers since privatisation. We strongly believe that the current incentive on DNOs to make capital efficiency savings should remain largely unchanged, but with some appropriate protection, as we suggest in our appendix, to ensure they are not abused.

We would also point out that treating opex under the same rolling mechanism as capex may lead to other undesirable consequences. The longer term benefits to customers will be significantly reduced as fewer cost reduction schemes become economically justified. In addition, this lower incentive regime on opex is exacerbated by Ofgem's latest stance that all severance and associated pension costs should be at shareholders' expense.

We believe that the strong incentive on opex must be maintained, that Ofgem and the DNOs should develop more prescriptive definitions of opex and capex to support this and, as we set out below, that severance and pension costs should be borne by customers.

Comparative Efficiency Analysis
The top down benchmarking analysis that has so far been conducted by Ofgem during this price control review has been on the basis of operating costs plus total fault costs. We are concerned about the apparent omission of capital costs from the efficiency debate. Efficiency needs to be considered not just in the context of operating costs, and we do not accept that including capitalised faults in the analysis is an adequate substitute for conducting total cost benchmarking.

We are also extremely concerned that a robust analysis of the drivers of costs has not been conducted, as previous detailed analysis that we have commissioned and shared with you has demonstrated. Our latest analysis also shows that it is not possible to draw robust conclusions about the relative efficiency or inefficiency of a DNO, especially when confidence intervals are applied to the results to address the risks of the uncertain analysis. We will share our latest analysis with you in more detail prior to our forthcoming meeting, but we strongly advocate an assessment of costs based on average, not frontier performance.

The Treatment Of Mergers
As we have made clear in our recent discussions with you, we are fundamentally opposed to Ofgem's suggestion of treating all DNOs the same, irrespective of whether they had merged or not in 2002/03. We do not accept that the types of synergies that have been achieved by merging two or more DNOs can be replicated by a single DNO that happens to be part of a wider group and, indeed, your separation rules largely prohibited such activity. There is no opportunity for a single DNO to extract any synergies in distribution-specific functions such as asset management, regulation, work scheduling, MPAS, control rooms and use of common IT systems and contractors. In contrast, two DNOs that have merged can combine these functions and hence lower average costs, which is why merger transactions between DNOs have continued to take place during the current price control.

Such factors must be taken into account, not only when conducting the benchmarking analysis, but also when translating the results into an overall allowance for 2005-10. In particular Ofgem must allow all merger benefits to be retained for a full five years. Without this commitment, Central Networks will be exposed not only to the £32m merger tax, but also to losing the financial benefits of the synergies on which the investment was based. This would be contrary to our discussions with Ofgem at the time that made clear that such savings would be retained by the company for five years before being passed back to customers through the normal regulatory process. Such a fundamental change would add to regulatory risk and undermine investment.

Pensions
We also have significant concerns regarding the current proposals on pensions, in particular the treatment of Early Retirement Deficiency Costs (ERDCs). The current price control was set in the knowledge that the pension scheme was in substantial surplus. Ofgem set a very small allowance for restructuring costs in the full knowledge that previous surpluses had to be utilised. The use of pension surpluses to finance ERDCs is the most customer-beneficial use of such surpluses. DNOs were right to infer that the cost savings required would in part be financed by this source, because during the Law Lords review of NGC's use of pension surplus, Ofgem did not object to the company funding efficiency savings via this route.

Customers have benefited from substantial cost savings, and hence lower prices since privatisation than would otherwise have been the case, through the use of a proportion of the pension surplus to finance some of the restructuring programme. All costs associated with ERDCs should therefore be financed by the customer, and we do not accept Ofgem's latest position on this matter.

We look forward to further discussions with you on these important issues.

Yours sincerely

Bob Taylor
Managing Director

Central Networks' Detailed Comments on Ofgem's March 2004 Policy Document

The following detailed comments are structured to follow the order and numbering of Ofgem's policy document.

3. Structure of the Price Control

3.6 - 3.12 Revenue Drivers

Ofgem proposes to:

- retain the existing revenue drivers and their weights;
- use the *actual* number of consumers reported each year by the DNOs; and
- review the weightings applying to the various voltage categories within the units distributed revenue driver.

We support Ofgem's proposal to retain the 50:50 split of the revenue driver between units distributed and customer numbers.

However, we continue to believe that an adjustment will be required to the units driver, especially if there is significant penetration of domestic CHP (DCHP). One option to mitigate the risk to distributors is to add 3,500 kWh to the units distributed for every DCHP unit connected.

We note the proposal to move to actual customer numbers, and believe this could potentially improve the accuracy with which the driver mirrors distributor's costs.

However, care will be needed in relation to the customer number assumptions when setting the price controls. Growth in customer numbers is driven by regional economic factors and varies considerably between DNO areas. In setting the price control it would not be appropriate to assume that all distributors will have the same growth.

In addition, future patterns of growth in customer numbers are likely to be affected by the introduction of new licensed distributors. If these distributors are successful in procuring networks embedded within existing DNOs' networks, this could have a substantial negative impact on the future growth of customer numbers. It will not necessarily be the case that DNOs' costs decrease in a way that is proportional to the reductions in growth in customer numbers, especially where smaller private networks are connected at low voltage. It may be necessary to make some sort of special allowance for such networks.

We agree that it would be appropriate to adopt the definitions of customer numbers used in the IIP RIGs.

We note the proposal to review the relative weightings applying to the various voltage categories within the units distributed driver, and to publish revised weightings in the June document.

3.13 - 3.14 Price Index

Ofgem questions whether CPI should replace RPI.

We note that Ofgem is considering changing the inflation index used for price control purposes, moving from RPI, to HICP (CPI). The main justification for this seems to be that the Treasury has changed the basis of the MPC's inflation target from RPIX (not RPI as stated in the paper) to CPI.

The CPI has been available for many years and we do not see a reason to change simply because the Government has now adopted it as its central inflation measure. This line of thinking would imply that RPIX should have replaced RPI some time ago. RPI is the broader index and has been chosen by a number of regulators. Its use is both time-honoured and well understood.

We are unclear that there would be any advantage in moving to CPI. If the ability to mirror DNO costs is to be a criterion for selecting an inflation index, there is no reason to suppose that CPI would do this any better than RPI. It is unlikely that any general inflation index will perfectly reflect DNO costs, but, given that labour bargaining on pay negotiations typically uses RPI, this will reflect the labour element of DNO costs more closely than CPI.

As the absolute levels of RPI and CPI are likely to remain different going forward, with no difference in the absolute levels of costs, any move from one index to the other would require a compensating adjustment to the 'X' term. It would be very difficult to demonstrate that any such adjustment was fair and neutral.

We believe the approach, proposed by Ofwat and other regulators, to continue using RPI in DPCR4, but to consider changing to CPI in subsequent review periods, following a measured analysis of its implications, is a robust way forward.

If Ofgem decides to adopt CPI as the inflation index in future, it will be important to demonstrate the exact scale of any associated adjustment to 'X' by showing what this would be on both the old and new bases well before the price control is finalised.

3.16 - 3.20 Transmission Exit Charges

Ofgem proposes to leave the treatment of exit charges unchanged.

We support Ofgem's proposal not to change the treatment of transmission exit charges at this review.

3.21 - 3.25 Wheeled Units

Ofgem proposes to allow the pass-through of the costs associated with wheeling charges and include the revenue associated with wheeled units within the price control.

We believe it will be important to clearly define 'wheeled units', especially as the numbers of embedded licensed distribution systems begins to increase, and the possibility of 'nested' systems becomes more real.

We welcome the change to allow pass-through of all costs associated with wheeling charges, as this will create a level playing field for wheeling and NGC transportation.

We accept that a DNO receiving the wheeled units would have no incentive to minimise the charges it pays, as its costs would be passed through to customers. However the submission set out in the forecast business plan questionnaire (BPQ) did not include any costs for reinforcement to facilitate the wheeling of units. Consequently, we are not clear as to how this would be funded if it were to be included as revenue within the price control.

A way forward to address this issue is to apply the same treatment for new EHV wheeled units as for new connections made at the EHV level for DPCR 4, and hence we advocate its inclusion within excluded service revenue. Ofgem would still be able to determine whether the costs incurred were efficient. For HV and LV connection, the costs of reinforcing the network for distributing wheeled units are not significant, and hence we would expect the full cost contribution to be recovered.

There is also a capital efficiency issue that will need to be resolved. If a DNO achieves £1m of savings, it is able to retain the benefit for a fixed period. However, if an additional £1m were incurred for new EHV connections in the same year, this would offset the efficiency savings. Given that the Electricity Act provides an obligation on DNOs to offer terms to connect, we believe that this needs to be recognised in the rolling capex incentive scheme, by excluding it from the calculations. However in the following price control, the wheeled unit costs incurred will need to be added to the RAV to fully finance the costs over the remainder of the regulatory asset lives.

3.26 - 3.32 EHV Charges

Ofgem proposes to include EHV charges within the scope of the price control.

It is proposed that charges for any new EHV connections made during the next price control period are treated as excluded service revenue until the next review in 2010, when Ofgem would expect to include them within the price control.

We welcome Ofgem's pragmatic proposals on EHV charges, given the difficulty in forecasting costs associated with site-specific customers. We believe DNOs and Ofgem should seek to produce a robust driver during the next price control period so that EHV units distributed for new connections can be brought within the scope of the price control in DPCR 5.

3.33 - 3.40 Non-contestable Connection Charges

Ofgem does not propose to change the price control treatment of connection charges in respect of reinforcement for demand consumers for this price control, but will require DNOs to establish and publish a clear schedule of charges.

Ofgem considers that the current voluntary standards of performance for new housing estates should be extended to cover all new connections, but does not intend to attach financial penalties to them yet.

We support development of the competitive connections market, and agree that effective competition, where appropriate, will provide the best protection for consumers.

We support Ofgem's proposal not to change the treatment of connection charges in respect of reinforcement for demand customers.

We note Ofgem's proposal to require DNOs to establish and publish a clear schedule of charges for non-contestable services.

We note Ofgem's view that the current voluntary standards of performance should be extended to cover all new connections, and support the intention not to attach financial penalties to these standards at this point.

3.41 - 3.43 Other Excluded Services

Ofgem proposes:

- No change to the price control treatment of top-up and standby charges;
- No change to the price control treatment of non-trading rechargeables;
- No change to the price control treatment of other minor activities and charges.
- The treatment of units distributed to embedded networks should be consistent with that for wheeled units, i.e. included within the scope of the price control.

Ofgem is also considering the treatment of costs and revenues for networks that DNOs operate outside of their authorised area (i.e. 'out of area networks').

We support Ofgem's proposal not to change the treatments of top-up and standby charges, non-trading rechargeables and other minor activities.

We note that the treatment of metering excluded service charges is being considered as part of the work on developing separate metering price controls, and we will continue to take full part in the debates around the provision of metering services.

In relation to the treatment of costs and revenues associated with 'out of area networks', Central Networks does not currently operate any of these, but considers that such networks should be treated in the same way as any owned by a "non-ex-REC" network operator.

3.44 Rates

Until it becomes clear whether DNOs have acted efficiently and appropriately in the current valuation process, Ofgem will not provide any reassurance on cost pass-through. Ofgem expects to make a decision on the treatment of rates in the June Initial Proposals.

We have been negotiating hard with the VOA to reduce our rates bills, both directly at individual licence level and with other DNOs, via a specialist consultant retained via the Energy Networks Association. These discussions are ongoing, and we will continue to do all we can to ensure the VOA arrives at a reasonable settlement.

It is not clear what impact our arguments will have on the VOA, but we will discuss any subsequent appeal with Ofgem. We are confident that we will be able to demonstrate to Ofgem that rates should therefore be treated as a pass-through for each of our licences.

3.46 - 3.48 Dealing With Uncertainty, New Obligations and Costs

Ofgem recognises that DNOs may need protection from costs that arise between price control reviews. Ofgem will consider the most appropriate way of providing protection to DNOs for a very limited number of specific cost items, but does not believe it is appropriate to introduce a formal mechanism like that used by Ofwat.

We agree with Ofgem that the approach used by Ofwat should not be used due to its cumbersome nature, primarily because it requires a full opening up of the price control settlement. This is not in the interests of customers, shareholders or Ofgem.

Nevertheless we believe some formal mechanism is required, particularly where we are already clear that there will be a material impact in DPCR4, but are unclear about the absolute magnitude. Without a mechanism in place, either distributors will carry too high a risk and so materially reduce the financial adequacy of the business, or customers will bear the risk of paying for an allowance which ex-post turns out to be too generous.

Neither of these outcomes is desirable, and we believe they can be avoided by modifying the Ofwat approach so that it accommodates a limited number of specific cost items without the unnecessary bureaucracy of price control “re-openers”.

We advocate the introduction of a bolt-on to the basic price control allowance to address two areas of uncertainty:

- new obligations, generally resulting from new or amended legal requirements such as Environmental and Health and Safety decisions and;
- cost uncertainty, where at the time of setting the price control allowances, there is significant uncertainty about the level of costs likely to arise for specific categories, such as the Traffic Management Bill.

Under this proposal, it is envisaged that Ofgem would make an estimate of the likely costs incurred for these material items. During the price control period, April 2005 to March 2010, DNOs and Ofgem would be able to exercise the option to open up an item and propose a new cost allowance, likely to be as a result of new information. The other party would then have a limited period to either accept this proposal, or put forward an alternative allowance. If no agreement could be reached, then the matter could be referred to the Competition Commission for resolution, in the same way that currently exists for the main price control package.

A more detailed commentary on the mechanics of this proposal is contained in a paper submitted on behalf of the DNOs by the PCG.

Incentive Framework

3.59 - 3.63 Definition of Costs and Incentives

Ofgem recognises that under the current regulatory regime there is an incentive to capitalise costs. A change to the treatment of costs is proposed, namely to treat faults (and perhaps all repairs and maintenance) as capex.

The Frontier Economics report on balancing incentives highlighted that the incentive to reduce operating costs is greater than the incentive to reduce capital costs, and that DNOs might exploit this by capitalising operating costs.

We accept that this is an important issue that needs to be addressed in the review, but believe that such a radical policy change proposed at this late stage in the price control process is an overreaction and unnecessary.

Since privatisation, DNOs have removed significant costs from the industry, which has resulted in prices falling in real terms by 50%. As our business plan submissions have laid out, we believe there is now less scope for reducing future operating costs, but we have built in an ongoing efficiency stretch of 1.5% per annum.

The proposal to shift the majority of operating costs into the capital expenditure basket has ramifications for the incentive properties of the entire price control framework, and will bring into question the value of the savings we have been assuming for DPCR4 in our business plan submissions.

Treating at least some opex as capex will significantly reduce the out-performance opportunities, and therefore make it less likely that the marginal benefit of making a cost saving will more than offset the marginal cost of effort expensed in achieving it. This is more so given that the low cost efficiency solutions have already been implemented.

The following two examples demonstrate how we believe Ofgem's current proposal is worse for customers, and will lead to a regulatory framework that is more in line with rate of return regulation.

Assume a DNO is planning to make a one-off £1m opex saving. Under the current rolling mechanism, if the cost of delivering this efficiency is £500,000, the payback of the investment will be within the same year.

Ofgem's proposal to treat some opex within the rolling capex mechanism will alter the mechanics of the incentive significantly. Using a 7% pre-tax cost of capital, the efficiency reward (return only) for the five-year period is £350,000 before tax and hence the payback period is in excess of five years.

Secondly, if a recurring £5m opex saving is made, but the upfront investment cost is say 25% of an annual opex allowance of £50m, it will take 3.5 years after tax for the investment to break even. However, if 50% of opex is now treated as capex, the payback period increases to 6.7 years. Given a five-year rolling mechanism, Ofgem's proposed treatment would lead to such cost efficiency initiatives being abandoned.

This is not in customers' interest as future costs will be higher than they would be under the current framework.

This is not in customers' interest as future costs will be higher than they would be under the current framework.

We believe strong incentives on opex must be maintained, but we recognise Ofgem's concern over the balance of opex and capex efficiency incentives. We suggest a possible way forward is to agree over the next twelve months, very prescriptive RAG definitions over what DNOs can classify as opex and capex.

This is also necessary since such allocations are required for undertaking benchmarking analysis during periodic reviews.

We believe that Ofgem's proposal is an overreaction to the problem, that appropriate allocations of costs will be required for benchmarking in any event, and strongly urge Ofgem to reconsider its implementation for the next price control.

3.64 - 3.66 Incentives for Investment Deferral

Ofgem proposes to reduce the incentives for outperforming capital expenditure allowances by only allowing DNOs to retain the cost of capital benefit, compared with the current regime of depreciation and cost of capital.

We understand Ofgem's concern that DNOs may submit high capex forecasts, and then choose to defer the investment after receiving the allowances, and leave customers potentially paying twice for the same investment.

We do not accept, however, that reducing the incentive reward opportunities is the best way to resolve this dilemma. As our examples above show, the implication of such a policy is a reduction in the opportunity to employ innovative solutions because payback periods will increase. This will encourage DNOs to simply spend their allowances, virtually regardless of questions of efficiency. Furthermore, in the context of significant increases in asset investment, it seems to us somewhat perverse to reduce incentives on capex price efficiency – this is the time when capex price efficiency incentives should be at their strongest.

We believe the current capital expenditure incentives must be retained for the next price control, and hence the marginal reward be based on depreciation and return on the saving for five years.

To address Ofgem’s legitimate concerns, we propose below a number of modifications, which could be made to provide sufficient comfort that DNOs deliver the work that was submitted in their business plans.

High level capital monitoring
We advocate a “standard-form” approach to capital monitoring, with short explanations of variances between planned and actual volumes delivered. This is the cheapest and easiest solution in our view to implement. There is merit in using a material variance threshold before commentary is required to accompany the data. Variances will inevitably arise, often because of differences in planned and actual timings of investment, and hence we do not believe it will make sense to explain and investigate every single variance. Pragmatically, we suggest using a variance of +/-5%.

The reporting table below for capital monitoring purposes is essentially a combined summary of business plan questionnaire tables 12 and 26. This will facilitate consistency and transparency with the DPCR4 settlement.

Table 1 Capital Monitoring assessment

	Additions		**Disposals**
	Load-related Volume	Non - Load related Volume	Non - Load related Volume
Transformers (units)			
Allowance			
Actual			
Switchgear (units)			
Allowance			
Actual			
Substation Other (incl sites)			
Allowance			
Actual			
Overhead Lines (km)			
Allowance			
Actual			
Underground Cables (km)			
Allowance			
Actual			
Services (units)			
Allowance			
Actual			

We envisage this table being used to report on the volumes of the whole capital programme, with supplementary notes on the progress of specific projects as outlined below.

The information that would be reported is as follows.

1. High volume but low value assets
These can be reported on and assessed almost mechanistically – planned volumes and costs against actual. We envisage no reporting on these other than by the summary table.

2. Major projects
Major projects will probably require more detailed post-delivery analysis. For Central Networks there will be between 10 and 20 per year for each DNO. We envisage the report on the whole capital programme being supplemented by commentary on the status of the projects which have been or are live during the year concerned.

3. Programme of Specifically-allowed-for Projects
These are projects, which are not "major", but which have specific allowances made for them at the time of the price control settlement. Examples include investment for quality of supply improvements or allowances for over-stretched switchgear or CONSAC cable. There are typically few of these, but we have assumed Ofgem would like to have assurance on investment in such projects. We envisage reporting on them in the same way as that proposed for major projects.

We believe that this proposal is a pragmatic solution to the problem outlined in the policy paper, and one which will provide Ofgem with ongoing reassurance that we will be delivering the network investment we have submitted between 2005 and 2010. Questions regarding cost and efficiency should be dealt with mainly as they are now, as part of the five-yearly review. If this process model is accepted then asset volumes are all that Ofgem needs to monitor between reviews.

An annual review, delivered each year, possibly at the same time as the Regulatory Accounts, which reports on volumes installed in the previous regulatory year, is the simplest form of monitoring and would facilitate "routine".

There are a number of options available for monitoring investment delivery. Whilst our preference is for the DNO to publish a "standard-form" approach, with short explanations of variances between planned and actual volumes, we are prepared to consider the monitoring being undertaken instead by independent reporters, in much the same way as they are used by Ofwat in the Water Industry.

Sliding scale approach to capex efficiencies
If this does not provide Ofgem with sufficient comfort, it could be complemented by a sliding scale approach to capital efficiency rewards. For example, if the capex under-spend from the allowance was within a threshold of X%, the incentive payment should be based on the full depreciation and return element. However if it falls outside this range but is within a Y% threshold, then the incentive payment could be reduced to the return element only. A significant under-spend that is more likely to arise from inappropriate investment deferral should not be rewarded. Therefore we would propose that under-spends exceeding Y% receive no rolling capex payment. Such an approach could be applied symmetrically and hence deal with capex overspends.

Increasing output incentives
We envisage that over the next few years, Ofgem and the industry will be working together to develop a robust measure of monitoring underlying network resilience. If sufficient progress is made, in the same way that the IIP was introduced mid-way through the existing price control, network resilience measures could correspondingly be reported during DPCR 4. Potentially, this could then be used as an eligibility test for qualifying for the rolling capex incentive, based on depreciation and the cost of capital of the marginal saving.

3.67 Treatment of Capex Overspends
Ofgem may allow some or all the recovery of cost overspends subject to at least one of three tests.

We welcome Ofgem's broad commitment to allow efficient overspends on capex. It is especially welcome in the context of the forthcoming period of significant capital investment.

The precise treatment of overspends remains uncertain, and clarity on rules and definitions for the three proposed tests will be required, particularly on how judgements of efficiency will be made. We believe there is merit in applying a sliding scale approach, as suggested above for dealing with investment deferral. We look forward to hearing more from Ofgem about this.

We would point out, here, that we have fully invested our allowances for DPCR3, including the re-investment of price efficiencies.

3.68 - 3.81 Losses
Ofgem proposes that reported losses should simply reflect the difference between the estimated volume of electricity entering and exiting the distribution system.

Ofgem considers that some form of limited protection from the impacts of distributed generation on losses is appropriate.

We support Ofgem's proposal to change the definition of losses, so that it simply reflects the difference between the estimated volumes of electricity entering and exiting the distribution system.

We are concerned though with the way the fixed five-year target is calculated. Using settlement data for the 1998–2004 period produces very volatile results. We propose therefore that the data used in this period, which has a weight of 60% of the DPCR 4 benchmark, should be normalised to ensure that the real underlying level of losses is the basis for setting the target. Similarly, the calculation of the incremental increases and decreases in losses going forward into DR4 should also be adjusted, where necessary, to ensure that the real underlying level of losses is the basis for setting the increments.

We agree that some protection is required against the possibility that distributed generation significantly increases losses. This is appropriate because the types, volumes and locations of distributed generation connecting to distribution systems, and any associated increase in losses, are largely outside DNOs' control.

The proposal that reported losses should be adjusted to reflect the impact of distributed generation (DG) where this significantly increases losses seems appropriate. However, the suggestion that this should be triggered when the level of the relevant loss adjustment factor (LAF) is 0.99 or lower - because at this level the benefit of the DG incentive would match the negative impact on the losses incentive - seems flawed. The intention of the DG incentive is to encourage DNOs to welcome DG, rather than to compensate for any detrimental effect that it might have on losses.

There is also an issue with DG connected at HV or LV, rather than EHV. Such generation is normally subject to 'voltage general' LAFs, which are the same for demand and generation, rather than site specific ones. Voltage-general LAFs are always greater than unity because they primarily relate to demand. The arrangements for LAFs in settlements do not support large numbers of different site specific LAFs, and so limiting the use of site specific LAFs to EHV connections is a sensible compromise.

Whilst individual HV or LV connected DGs are unlikely to have a material impact on losses, if large numbers of a particular type had a similar impact, the combined effect could be significant. If this happened, then, under the current arrangements, there would be no trigger for adjustments to be made to units distributed.

It may be that further 'voltage general' LAFs will be required for HV and LV connected DG that has the effect of increasing losses. Care would be needed in doing this and, if this proposal goes ahead as set out in the paper, it would be sensible to provide some form of guidance on this issue.

We note Ofgem's intention to write to DNOs in April to discuss issues surrounding the possible need for transitional arrangements. Central Networks do not see any need for transitional arrangements between the two incentive regimes. We acknowledge that there will be initial differences in the rewards or penalties faced by individual DNOs, but believe these will be small. Such differences are only to be expected when an incentive is changed and, given that the proposals to strengthen the losses incentive have been public since January 2003, will certainly not be "unanticipated".

Furthermore, since the proposal to strengthen the losses incentive was first made there has been a perverse incentive for DNOs to delay loss-reducing investment, thereby saving on capex and increasing their fixed losses target for DR4. Any transitional arrangements would further reward such behaviour, and conversely, would penalise DNOs that have undertaken successful loss reduction initiatives in the DR3 period.

3.82 - 3.101 Price Control for Metering Services

The policy document discusses a number of possible options for metering.

Form of Price Control (Price Caps v Average Revenue Caps)

In assessing the options, the form of any price control for metering must:

- be simple to implement, regulate and operate;
- be flexible enough to reflect the variability of annual work volumes, losses of market share and the impact on efficiency;
- be robust;
- not distort or restrict the operation of the competitive market;
- seek to promote efficient behaviour through the use of the right drivers; and

- allow the DNOs to recover any stranded investment or other costs in meeting their licence requirements.

Whilst both price caps and average revenue caps could achieve the above aims, each has their strengths and weaknesses.

We welcome the view that price caps for basic domestic meters linked to non-discrimination provisions should form the basis of the MAP price control. However, we are concerned that the approach outlined for an average revenue cap for MOp will be too simplistic and lead to significant issues in the operation of the price control.

It is unlikely that the few drivers identified in the policy document would be able to accurately track the volatility of costs and activity levels within metering.

Metering has several discrete drivers on volume and each of these operate independently on several classes of meter, which have significantly different costs to operate. For instance, a visit to a CT meter can be several times the cost of the same visit to a single-phase meter. Not only is there such a variation in the cost of similar jobs, but also there are a number of different types of activity. These can range from a few pence per visit for tariff changes, which can be undertaken by meter readers, to hundreds of pounds.

Providing the mix of meter types and activity levels remained constant such differences would not cause an issue. However, not only is there significant volatility in the mix of jobs on a normal basis (e.g. due to changes in the statutory change programme), but the mix could change substantially as Suppliers selectively de-appoint DNOs as meter operators. This is illustrated by the fact that BGT are de-appointing for domestic type meters only, leaving the higher cost activities with the DNOs.

With such diverse and numerous combinations of activities, the number of drivers would need to be significant to satisfy the criteria discussed above. There would need to be a minimum of four different types of activity driver linked with a split of meter types, for example:
- Single-phase, one rate
- Single-phase, 2-rate
- Pre-payment, all types
- Poly-phase, one rate
- Poly-phase, multi rate
- MD/CT
- Timeswitches

Note : this assumes that any special metering would continue to be an excluded service.

This number of drivers is potentially over-complicated and unmanageable. Reducing the number of drivers will reduce complexity, but increase the risks that the market would be distorted and/or the recovery of income by the DNOs would not reflect the costs of the activity.

Furthermore, if insufficient drivers are used to set an average tariff cap, the outcome will be annual revisions of tariffs to correct for ongoing over- and under-recoveries.

Such a process would lead to instability in prices as well as adding significantly to the regulatory burden.

We are of the opinion that MOp could have a similar control to MAP with a small number of price caps and either a non-discrimination provision or alternatively linked with an approved pricing methodology for other services. This would provide the benefits of simplicity and ease of operation as discussed above with the rigour of ensuring non-discrimination in pricing other services. It would avoid the issue of over- and under-recoveries and should provide a sound basis for the development of the competitive market.

Stranding

The issue of protection for stranded costs is not, as suggested in the Policy Document, one of being shielded from competitive pressures, but concerns the ability of DNOs to recover the costs incurred in meeting past and future licence obligations. DNOs incur costs, which would not be faced by other metering organisations which do not have the extensive range of obligations of DNOs.

In order to provide a framework which is supportive of the long-term development of metering competition, Ofgem must seek to put in place a control which sufficiently minimises the risks and provides the returns capable of being sustained in a competitive market.

In order to achieve this, Ofgem must allow DNOs to recover past costs to fulfil their licence obligations, which are now out of market (i.e. pension and salary costs, IT costs and investment in metering assets) within the distribution price control. This principle has been recognised in part through the writing-down of assets to their modern equivalent, defined as the Depreciated Replacement Cost.

What must be recognised however is the fact that, with the market being in its infancy, both new and existing participants appear unwilling to risk stranding where the potential exists for them to lose a significant proportion of their customer base. No realistic rate of return can adequately compensate the DNOs for facing such a risk as part of their licence obligations. Ofgem must therefore provide mechanisms to allow us to recover unavoidable costs which arise from our obligation to provide a universal service even as market share reduces.

For MAP, it is recognised the Ofgem has addressed some of the concerns with the proposed use of a depreciated replacement cost valuation. However, this still leaves significant exposure to the early removal of meters by suppliers. Termination payments are just one of the possible mechanisms for dealing with this. It is our view that, rather than a price control specifically prescribing termination payments, it should be more a case of Ofgem not excluding the option to put in place such commercial terms to protect investment.

For MOp, DNOs will incur not only substantial legacy costs linked to having a 100% licence obligation in the past, but they will also have ongoing obligations in a reducing market, which will significantly increase the cost-to-serve in the future. Any mechanism in place to recover past investment should also ensure recovery of such additional costs.

Basic Metering Services
We note that the discussions on 'basic' metering have moved on since the publication of the March Policy Document and that further options have been considered.

We are of the opinion that the alternative based on the historical position has several issues and we do not support such an approach. The changes in contracts and services which have occurred since REMA and any changes in meters being provided will make it difficult to set such services (it may mean that DNOs would have to offer services which are less efficient than those currently provided or do not meet the requirements for REMA).

We would however support an approach using a functional definition for MOp services and a technical definition for MAP services as discussed in David Howdon's paper of 15 April 2004.

Prepayment Technology
Using a technical definition for MAP services will allow for the three prepayment-meter technologies to be defined as basic metering services and would provide price caps regardless of the approach taken by the DNO. In setting such price controls, Ofgem will need to take into account the issues regarding the risk of premature replacement of these meters by suppliers. BGT have already indicated that the token meter technology used in the Central Networks region will be replaced with key meters. Such action will lead to substantial stranding of investment and any price control must allow for the recovery of such investment.

4. Quality of Service

Ofgem expects that phase 2 of the "Customers' Willingness To Pay" (WTP) survey will inform some of the potential changes to Quality of Supply performance including the level of some of the targets and incentives. In our response to the December document we stated our belief that the survey is unlikely to deliver definitive answers, and we understand that Ofgem acknowledges this point and that the WTP survey forms but one element in the decision making process. However, particularly regarding longer term aspirations such as improved network storm resilience and sustainable network performance, we still consider that Ofgem, in conjunction with the DTI, needs to make societal decisions in order to shape future direction.

For clarity we state again the general principles which inform our thinking with respect to Quality of Supply:

- Because networks will *always* be subject to events which result in customer outages, delivery of quality of supply (QofS) is best achieved through a network which is *generally* more reliable.
- For the purposes of network performance we do not believe in discriminating between different groups of customers except in terms of network characteristics. Quite apart from our obligation not to discriminate, the network itself "does not readily distinguish" between customer groups.
- Consequently, delivering different QofS to different customer groups is effectively undeliverable.
- Distinctions between customers groups can be made for the purposes of more general, non-network services, but there must be robust and compelling grounds for making such distinctions.
- There must also be robust and practical means of identifying and maintaining any such customer groupings.

We believe these principles are largely realised in the current framework of GS for individual customers, IIP for overall performance and licence conditions for specific obligations. We have welcomed the opportunity through participation in the Ofgem / DNO Quality of Supply Working Group (QofS WG) to discuss and influence the format of the Quality of service and other outputs from the network. We believe this group has facilitated a valuable exchange of ideas; indeed, the proposals in this section have benefited from the work. However, the interaction of some of the proposals, particularly under severe weather conditions, needs to be developed further.

We therefore support ongoing dialogue with Ofgem through the QofS WG and present here our main views on Ofgem's proposals.

4.3 - 4.21 Guaranteed and Overall Standards of Performance

Guaranteed standard on supply restoration
Ofgem proposes separating the Guaranteed Standard (GS) for restoration (GS2) to cover normal and severe weather conditions building on the interim arrangements introduced following the October 2002 storms.

The principle of a GS is that it should set minimum standards that are attainable, and that the standard should allow an efficient DNO to be capable of avoiding payments for failure. We note that Ofgem does not propose any tightening of the standard during normal weather and support this proposal. The Q of S WG has helped develop thresholds for normal and severe weather that will be both practical and easily understood by customers based on the interim arrangements. We comment further on the proposed severe weather arrangements in the network resilience section.

We do consider that the distinction between normal and severe weather conditions needs to be clearly defined for what will become in practice a “double” GS. Some flexibility will need to be retained though, so that the arrangements can be developed in the light of experience. Consequently, we are supportive of the proposal outlined at the 14/4/2004 QofS WG that the actual storm thresholds would be best covered in a licence condition rather than a Statutory Instrument.

Automatic payments

Ofgem proposes that companies should pay out automatically where possible and proactively contact customers in general to make them aware of their right to compensation when there is a breach, i.e. move to a “semi-automatic” payment system. Ofgem also proposes to introduce an equivalent penalty where the payment is not made as an incentive not to discourage claims.

We support the concept of semi-automatic payments, but for GS2 during normal weather conditions only. This fits with our principles of good customer service practice and is similar to the ex-gratia scheme we presently operate for this restoration standard.

We believe semi-automatic payment should be limited in this way on the grounds of practicality, efficiency and service-priority.

At root there are two broad problems, which inhibit DNOs from making GS payments automatically:

- Lack of full LV phase connectivity, which makes accurate identification of interrupted premises difficult;
- The supplier hub principle, which means that DNOs lack up-to-date information on customers’ names.

When customers go off supply during normal weather conditions, our “front-line” field staff can usually make up for these deficiencies by obtaining most of the information needed to make payments directly and readily from the customers or sites affected.

Under storm or other exceptional conditions, collecting such information is typically much less easy to collect, partly because of the conditions, but also because of the volumes involved. More importantly, the priority for our field staff is, and we believe should be, on solving the network problems, which have caused the interruptions in the first place. Consequently, we believe for storm conditions and other exceptional events that the current arrangements should stand, i.e. the customers should claim.

A potential solution is to allow DNOs access to customer databases directly, and we would support further exploration of this option

With respect to the other standards we support the idea of DNOs being more proactive in increasing the awareness of GS, whilst still placing the onus on customers to make a claim.

Compensation for business customers

Ofgem considers that arrangements for business customers connected at HV and above should be considered in light of the WTP survey.

We welcome Ofgem's view that it is not appropriate to differentiate between network performance for domestic and business customers connected at LV.

Whilst Ofgem awaits the findings of the survey on HV consumers' willingness to pay for higher levels of compensation, we would point out that, unlike other customers, those connected at HV and above do get the opportunity to mitigate against the risks of supply interruption either by influencing network design, especially at the time of connection, or by taking measures of their own, for instance, investing in back-up generation. We would argue that, insofar as HV consumers do not take these opportunities, they express a willingness to take on the risks of supply interruption and a corresponding unwillingness to pay for extra protection.

If the level of compensation to this group of customers is to be increased, perhaps as a result of the findings of the WTP survey, then we believe there should be a reciprocal level of cost pass-through, which should be borne by this group of customers only.

Priority service customers

Ofgem proposes not to introduce a new GS focused on vulnerable customers, but considers that other measures, informed by the WTP survey, such as a dedicated help-line, could be introduced.

We note that Ofgem no longer considers it appropriate to introduce a new GS focused on priority service customers. We support this view and welcome the opportunity to work with Ofgem and the industry to develop an alternative approach to priority service customers. In particular we consider that the following aspects need to be taken into account:

- It is essential that there is a clear and strong definition of a priority service customer and just what information should be held in an improved Priority Service Register to facilitate any services to be delivered.
- The actual numbers of priority service customers should be of such a size that a differentiated level of customer service can be provided both effectively and economically. We believe the definition should be limited to those customers that have a medical dependence upon electricity.
- If large numbers of customers are captured by the definition, Ofgem will need to consider the funding requirements of any changes to our services.
- DNOs can only have very limited responsibilities in this area. Responsibility for medical provision, for instance, must be the responsibility of the normal agents of social or community care.

The role of the overall standards of performance

Ofgem proposes to replace some and enhance other OSs with monitoring and publication under IIP.

We support the replacement of the Overall Standards, including their thresholds, by the collection of similar, and in certain instances, enhanced data under the IIP regime. If we are to maintain data quality, we consider that it will be necessary to

extend the data timescales prescribed in the licence, especially when the provision of disaggregated network performance data for QoS purposes is taken into account. We believe extending the timescale a month, from the end of April to the end of May would be appropriate.
We comment under separate cover on the changes to the RIG in order to ensure robust data collection for both the new additions to and the existing OS data.

Other amendments to the Guaranteed Standards of Performance
Ofgem considers that in general the existing suite of standards provide sufficient incentives. However Ofgem is considering an appropriate level for the multiple interruptions standard.

The multiple interruptions GS is relatively new and was indeed the first GS to embody a commitment to an efficient level of compensation cost recovery from its inception. Any changes will have the effect of significantly increasing the numbers of customers eligible to claim and will in fact move this GS further into the arena of being "pure" compensation rather than a standard to achieve. Consequently, if Ofgem deems that a change to the interruption threshold, time band or value of compensation is appropriate from the WTP survey, then a corresponding allowance for cost recovery must be given or provision made for the appropriate network investment in DPCP4. The FBPQ submissions of the DNOs provide indicative costs but these would need refining once any changes become clearer. In our view the costs of carrying out the changes are unlikely to be cost effective.

4.22 – 4.43 Reviewing IIP

Provision of disaggregated interruption data
Ofgem proposes to modify the RIG to include additional reporting requirements for:

- disaggregated performance data by HV circuit for CI/100c and CMLs
- disaggregated performance data by the number of customers interrupted by duration band.

We support the formalisation of the collection of performance data disaggregated by HV circuit to support the Ofgem/DNO work on comparing quality of supply performance. Although, the draft RIG v5 prescribes the actual data that should be provided, and we have commented separately on the detail of the information to be provided, we would point out here that an incident count needs to be added to the CI/100c and CML data. Additionally, with respect to the banding of customers, we understand that the draft RIG contains Ofgem's latest requirements.

Finally, we note that Ofgem does not propose to introduce performance targets in respect of these measures at this review, and we understand there is no requirement to subject this part of the data to a formal audit. We would however support the ongoing use of the Ofgem/DNO QofS WG to further understand and enhance the development of the comparative work that this information facilitates. Further understanding with respect to the definitions of HV circuits and the impact of the quality of the length information on the disaggregation groups into which a specific circuit is allocated would be beneficial

Worst served customers

Ofgem proposes to modify the RIGs to introduce a new requirement for reporting of the number of customers experiencing particular frequencies of interruption each year.

We support this proposal which will replace the obligation to report against the MI OS. We note the move to exclude LV voltages from the reporting regime. We also welcome the view outlined to the QofS WG 14/4/2004 that it will not be necessary to submit any force-majeure-corrected data on worst served customers.

Connections

Ofgem propose to transfer the existing reporting requirements for the percentage of customer connections provided within a given time period to the IIP framework.

We support this.

Form of the incentive for interruptions to supply

Ofgem proposes to retain the current incentive scheme but move to annual rewards and penalties.

We have already stated that we support the introduction of an incentive scheme with annual rewards in the future similar to those existing for the final year of the current scheme. We believe that the rewards should be symmetrical to the penalty exposure to provide a balanced incentive for DNOs to outperform the annual targets.

In previous responses we have outlined the need for the scheme to accommodate the natural variability in network performance. Whilst exemptions from the scheme will address variability under severe weather and other exceptional events, there is the issue of annual volatility under "normal" weather conditions to be addressed. We note that Ofgem is not minded to introduce deadbands or rolling averages to accommodate for this variability relying instead on the intention to introduce a symmetrical scheme. However, we understand that the results of the WTP survey will be utilised before coming to the final decision. We have already commented on the desirability of a symmetrical scheme so as to give a balance to the incentives for a company to perform. However if an asymmetrical scheme is finally chosen an additional form of compensation for natural variability will become a pre-requisite. For reasons outlined in our previous responses we consider that the use of deadbands is the only form of acceptable "compensation" in these circumstances.

Notwithstanding this, even if a symmetrical scheme is the final outcome we are still very concerned that it should not be seen to be packaged as a rewards and penalties regime. This could set unrealistic customer perceptions and expectations with respect to DNOs' control over network performance. The use of a five-year settlement period as opposed to the single-year settlement would assist in diluting such a perception.

Weighting of planned and unplanned interruptions

Ofgem proposes to establish the weightings between planned and unplanned interruptions taking account of the results of the customer willingness to pay survey.

Following on from the 14/4/2004 QofS WG we understand that Ofgem will set out proposals on how a change in weighting between planned and unplanned interruptions will be applied in practice and we await further information against which to judge the methodology. Notwithstanding this, we are not convinced that different weightings are required. If the weighting attached to planned interruptions is set low, there is the potential for stranded assets (e.g mobile generation). Additionally, although the future weightings will be informed by the outcome of the second phase of the willingness to pay survey, we consider that this will only reflect a view against a background of the current levels of equal weighting.

Audits and adjusting data for inaccuracy

Ofgem proposes two options for the audit framework for the next price control period. Ofgem also proposes that in the next price control period performance data should be adjusted for any inaccuracies identified by the audits

We consider that option one is a stepping stone to the long-term aspiration of option 2. Consequently, we would support the introduction of “streamlined” audits for the next price control. These could be used to drive out reporting inconsistencies so that a move to self-audit can be contemplated in the longer term.

With respect to the adjustment for inaccuracies, if a DNO falls outside the accuracy bands we urge caution against replication of the current mechanism, which involves bringing the company to a 100% accuracy level. Although not yet observed, if such an adjustment were to cause a company to either just pass or just fail its IIP target, it would raise serious issues of comparable treatment. Aligning accuracy to the prescribed minimum limits of the licence condition or that of the industry standard could be undertaken and maybe a more appropriate adjustment made. However, any adjustment that is made needs to be treated against the background of confidence levels and a process that utilises a statistical sample to judge the accuracy of the whole population of incidents.

Target Setting

Ofgem proposes that targets under the incentive scheme will be addressed in the June initial proposals.

We note the proposal and welcome further discussion through the QofS WG on the appropriate methodology for setting IIP targets, in particular the starting points to be used.

We would point out here that the IIP targets will need to take into account increases in planned interruptions as these will necessarily increase to allow us to undertake the necessary investment in the network.

Treatment of Planned interruptions in final year of the current scheme

Ofgem proposes that DNOs should be allowed to roll forward up to 2 planned CIs and 3 planned CMLs from 2004/5 to 2005/6 to mitigate the incentive to defer planned work in 2004/5 to meet IIP targets. Companies are to notify Ofgem of their intention to take this option up by 30 April 2004

As we have stated previously, we do not believe the current IIP mechanism incentivises the deferring of planned work to the extent that causes Ofgem the concern outlined in the document. Additionally, we consider that the current proposal actually discourages DNOs from rolling forward any planned performance.

The details of the IIP scheme for 2005/6 onwards, particularly its targets, will still be unknown when the cut-off for rolling forward CMLs and CIs expires. Consequently, Ofgem is in effect asking DNOs to make a decision where key costs and benefits are unknown. Additionally, as the weightings of planned and unplanned interruptions have still to be decided there are also additional levels of complexity that will impact on the decision.

Frontier performance

Ofgem proposes that the disaggregated benchmarks will be used to decide whether a DNO can participate in the reward mechanism of the current IIP, whether or not they meet their final year targets.

This proposal may allow one or even more DNOs to secure a final year reward for which they may not be otherwise eligible. However, we consider that the process requires as a pre-requisite both a clear definition of what is meant by “frontier” together with an equitable methodology of establishing the so prescribed frontier.

We note the proposal to define frontier performance based on a comparison of network performance across the companies using the benchmarks established from the disaggregation work. We consider that this is approach needs to be treated with extreme caution for the following reasons:

- There will only be two years of data available and this is not a sufficient number of years of RIG compliant network performance data to ensure that the natural variability in network performance can be taken into account.
- The process established is still embryonic and its robustness as a comparison methodology is unproven as it is only based on three variables.
- There is no view taken of the total cost (opex & capex) of the performance which dilutes the concept of the frontier so identified

We therefore consider that the proposal has the potential for placing undue reliance on an embryonic process using at best two year’s data. We have undertaken statistical approaches to aid the understanding of Quality of Supply performance which we have shared with Ofgem and the WG. Even within an individual company circuit length / percentage of overhead line and customer density only explains 25% of variability in performance, with the other 75% of variance apparently being unexplained by any other single dominant factors.

We therefore urge extreme caution in this approach, and consider that it will be essential to examine ways in which historical data can be used to support any comparisons made, rather than rush towards a seemingly attractive but misguided reward methodology.

4.44 – 4.52 Network Resilience

Network Resilience Incentive mechanism

Ofgem has indicated that it is not possible to develop a robust incentive mechanism relating to the ability of a network to withstand severe weather as part of this price review. Ofgem proposes that it will carry out a programme of work with the DNOs and other interested parties to develop appropriate measures

We support the proposal and welcome the opportunity to further understanding of the reliability of networks during severe weather in conjunction with evaluation of the feasibility of developing output measures. This would be an appropriate area for input by the joint Ofgem/DNO QofS WG. It may also be an area where a research and development programme could be beneficial.

Although robust output measures may form a part of any future resilience incentive mechanism, the majority of investment in the network to improve storm resilience will only be quantifiable for the foreseeable future, even into DPCR5 and beyond, in terms of delivery of inputs, such as the replacement of certain assets. These will need to be used alongside output measures in any comprehensive network resilience incentive scheme. We also believe there needs to be clear evidence that either the customers are willing to pay for the improved performance or that a societal judgement indicates that improvements are desirable.

Restoration incentive following a severe weather event

Ofgem has indicated that it is appropriate to have incentives in this area and proposes to modify the interim arrangements associated with GS2 for the restoration of supplies following severe weather. These proposed weather arrangements may increase a DNO's exposure to the costs of making payments to customers.

Views are also sought on the concept of using annual caps both with respect to individual customer payments and to limit a DNO's overall exposure

We are supportive of the tiered approach outlined and welcome the retention of a discretionary approach for "very large" weather events. In order to ensure simplicity of the approach to customers, we would caution against the establishment of numerous payment thresholds. As we outlined in our response to the December 2003 document, the interim arrangements themselves are relatively new and the clarity they bring has been welcomed. We believe we should give the interim arrangements a chance to prove themselves in practice before considering whether they should be modified. Otherwise we are liable to be forever chasing weather events rather than establishing a certain and effective framework.

Moreover, the setting of the thresholds to differentiate between the different types of weather needs further analysis, and we support ongoing work in this area by Ofgem in order to inform the June initial proposals.

We also note that the proposed thresholds do not yet prevent the risk of multiple jeopardy, as performance of the DNOs could be still assessed both under the GS storm mechanism and the IIP. We believe, as a fundamental principle, that the arrangements for DPCR4 should not permit a DNO to suffer multiple penalties for the same event. Consequently, we believe that *force majeure* rules should be developed to ensure that any severe event incentivised under the GS storm regimes should be excluded from the IIP. The QofS WG is a suitable forum in which the interdependencies between an IIP *force majeure* event and the "storm" GS2 thresholds can be explored. In particular, the IIP materiality test, which has an element of perversity, and the subjectivity inherent in the mitigating-actions-test are areas for evaluation.

Finally, we remain concerned that the storm proposals will end up as a compensatory mechanism rather than a standard to be achieved. To avoid this, the interim level of capping of financial exposure should be maintained, and it is paramount that this is underpinned by an efficient level of cost recovery. In the absence of additional investment for network resilience the underlying interruptions to customers during severe weather events will remain at present levels.

4.53 – 4.66 Incentives For Telephone Response

4.60 Inclusion of Automated Messaging

Ofgem proposes to expand the survey in the next price control period to include consumers who have their calls answered by an automated message.

We believe there is value in expanding the survey to include customers who have listened to an automated message, but there remain issues with its practical development and implementation.

We are concerned about the possibility of some consumers being included in the survey twice. Consumers, who are dissatisfied with the automated message, can ring back and speak to an agent and so could be included in the survey anyway. Asking customers to complete a survey twice for the same initial concern is poor practice from a customer care perspective. In addition, it has the potential to bias the results of the survey.

Although it has been established there are no issues regarding the data protection act from a DNO perspective, we still have a customer care concern regarding the passing of customers' personal details on to a third party without their prior knowledge and consent.

Crucially, this latter concern is also shared by our telephone service provider, BT, who refuses to pass on the call details of consumers who have listened to an automated message. BT encrypts all the call line identification information contained in the raw call data because they are concerned that not doing so would contravene data protection regulations.

Consequently, whilst in principle we support the idea of expanding the survey to include recipients of automated messages; in practice we are currently unable to identify customers for this purpose.

4.61 Survey Questions

Ofgem believes there may be scope for combining or rationalising some of the questions for the survey questionnaire and welcomes views on this issue.

We support rationalising the survey questionnaire and would welcome the opportunity to work with all interested parties to consider questions which will better identify customers' expectations.

4.62 – 4.63 Combining quality and speed of telephone response

Ofgem proposes to assess consumers' satisfaction with the speed of telephone response on a trial basis by including an additional question in the consumer survey. The results from this will be shared with DNOs and will help inform Ofgem as to targets for performance.

We are broadly supportive of the proposal to assess satisfaction with speed of response by means of a trial question in the consumer survey. We believe there is merit, at least in principle, in comparing customers' perceptions of speed of response with the quantitative reality described by the detailed statistics on actual speed which we provide every month.

It remains to be seen whether useful results will emerge from such an additional question, but, at this stage, a number of caveats must be borne in mind, especially if responses are used to inform targets.

- When assessing how satisfied customers are with the length of time taken to speak to an operator, they will be taking into account the length of time it takes to hear the message on the "mas box", listen to the Ofgem message and then the ACD queuing time. This is likely to distort customers' perceptions of the actual length of time taken to answer the call.

- Overall public perspective has shifted in recent times and customers now have higher expectations with regard to service. This includes, in some cases, that telephone calls should be answered straight away. In such cases these customers may not even be happy to wait for 15 seconds in an ACD queue.

- Targets set for the telephone speed of response will need to take into account the two different types of call handling systems as detailed in the RIG version 5.

4.67 – 4.74 Environmental Outputs

Ofgem proposes to introduce reporting of a small number of Key Environmental Performance Indicators.

We support Ofgem's recognition of the environmental responsibilities of DNOs. However, we still consider that the introduction of monitoring for environmental outputs of DNO activities without any supporting environmental objectives seems inappropriate.

We have commented separately on the proposed environmental measures in the response to draft RIG v5. However we raise here concerns with respect to the reporting of the details of the Schedule 9 statement together with the date of last review. We do not believe that reporting these adds any additional value. Also, we must not overlook the fact that the statutory consultees are the appropriate bodies both with respect to the detail of these statements and the relevance of the date of the last review. Therefore, we respectfully suggest that the obligation for Schedule 9 remains with the parties set out in the Electricity Act 1989 and are removed from Ofgem's proposed set of measures.

4.75 General Discretionary Reward

Ofgem proposes to introduce a general discretionary reward that incentivises DNOs in wider aspects of quality of service.

Whilst any opportunity to earn additional rewards is welcomed, the exact process for determining "winners" is an issue. We consider that advance knowledge of the "rules of the game" and just how achievement is to be judged will be a pre-requisite to the setting up of any such scheme. The incentive properties would need to be credible, objective and in our customers' interest before we would support such a scheme.

4.76 Undergrounding

Ofgem proposes to use the WTP survey to assess the requirements for undergrounding.

We note Ofgem's intention but would point out that the information we submitted as part of the FBPQ preferred scenarios makes allowance for a number of pro-active environmental improvements. These include selective under-grounding in areas of outstanding natural beauty or sensitivity, such as the Peak District National Park in the East of our territory and the Forest of Dean in the West.

We consider that these types of improvements are essential to help us to meet our obligations under Section 38 of the Electricity Act 1989 and Schedule 9 statement commitments.

5. Distributed Generation, Innovation Funding and Registered Power Zones

5.12 – 5.14 Incentive Framework

Ofgem proposes an 80 per cent pass-through rate for the incentive scheme.

Whilst we welcome Ofgem's decision to opt for the higher of the two potential rates of pass-through considered in the December paper, we are disappointed that Ofgem has removed the concept of a menu-based approach for operating the hybrid incentive scheme. We believe the proposed approach asks DNOs to bear unnecessarily high risks when connecting generators in locations where significant reinforcement of the network is needed. We will comment on how this should be addressed in our response to the incentive rates below.

5.15 – 5.17 Recovery of DG Revenue

Total revenue from the incentive scheme will normally be recovered from generators connecting to the network.

We note that it is intended that DNOs should begin recovering costs under the incentive scheme as soon as these are incurred. In practice, there may be a delay between costs being incurred on a particular connection, and the start of the associated income stream. We do not see this as a particular problem in the early days, but this may need to be reviewed if the volumes of DG connections become very large.

We believe that it is right initially to limit the recovery of the DG incentive scheme revenue (both pass-through and incentive rate) to use of system associated with DG connecting after 1 April 2005. We do not, however, believe that the revenue should be collected from generators, but rather from the parties that use the distribution system to convey export power away from the generators - typically electricity suppliers. This would be consistent with the collection of other 'normal' use of system charges, and is likely to be more efficient than billing generators direct, especially in view of the potentially very large numbers of these in the future.

We note that the pass-through element will be recoverable over the assumed asset life of 15 years on an annuity basis. While this provides a much flatter cost profile for the generator (or supplier) than the traditional 'RAV' approach, it does increase the DNO's funds at risk due to generator failure.

5.18 – 5.20 Stranded Costs

If some of the forecasted volume does not materialise or a generator ceases production, it is proposed that demand customers will fund only the pass-through element of the scheme.

We welcome the proposal to provide at least some protection against 'stranded assets', but note that this will be limited to recovery of the pass-through element of the incentive.

The success or failure of connected generators is likely to be a factor of market forces, and completely beyond the DNOs' control. In addition, DNOs have an obligation to connect under the Electricity Act and consequently it is not possible to refuse connection, even where there is a high probability that production will cease within the period set out for recovering the costs.

We therefore do not accept that DNOs should be prevented from recovering the incentive rate payments from demand customers over the full 15 year assumed regulatory life if, for example, a generator ceases production before the asset has been fully depreciated.

We are also unclear about the details of the proposed transfer of stranded costs to demand customers. Is it intended that up to a certain level, stranded costs will be smeared over other generators, and only above this level transfer to demand customers? If so, this seems an unduly complex approach with the potential to increase significantly the volatility in generator charges. We believe that all stranded costs should be passed through to demand customers, who should also gain the benefits of any increased levels or diversity of generation.

5.21 – 5.23 The Value of the Incentive

Ofgem has set the incentive rate for the remaining 20 per cent of costs at £1.5/kW/year for all DNOs except Scottish Hydro who have been allowed a higher rate to reflect the higher average costs.

We agree that, in general, it is appropriate to take the average reported costs across the industry to set the parameters of the incentive scheme. We also recognise that Scottish Hydro is a special case due to its geography and low demand density. As already stated, though, we still have concerns about risks from high cost schemes in our own areas.

In the business plans submitted to Ofgem, estimates were made for a number of generation technologies. A case study has been undertaken for Central Networks West based on a few of these technologies and the results are set out in table 1 below.

Table 1 Case study of DG schemes

DG technology type	Number of projects	Total Capacity 1.1 (MW)	Direct costs of reinforcing the network (£m)
Onshore wind 132 kV connection	7	70	5
Waste incineration 132 kV connection	2	40	4

The two schemes detailed above each consist of a number of discreet projects that could go ahead independently of each other. If either of these two schemes is commissioned, either in whole or in part, some existing 132kV switchgear will need to be changed to ensure plant ratings are not exceeded. As a consequence of this, the capital costs are likely to be very high relative to the capacity of the plant being connected, forcing average costs way above the assumed £50/kW that drives the 7.5% premium rate of return assumption.

A number of scenarios can be derived from the above forecasts. These are set out in table 2, where an analysis of the rate of return against Ofgem's central assumption is produced (excluding operating and maintenance costs).

Table 2 Rate of return for a number of DG scenarios

Scenario	Capacity MW	Direct costs (£m)	Cost (£ / MW)	Annual Payments (£m)	Rate of return* (%)
Onshore wind	70	5	71	0.530	6.45
Onshore wind	10	5	500	0.440	4.30
Waste incineration	40	4	100	0.400	5.55
Waste incineration	20	4	200	0.370	4.40

* assume floor rate of return = cost of debt at 4.30%

It can be seen from table 2 that, if the cost of connecting generators is at or above the high end of the range set out in table 5.1 of the policy document, that we will earn significantly less than the allowed cost of capital. This is not acceptable given we have little power to influence the location of connections following the removal of deep connection charges, and are unable to prevent connection in high cost network areas.

We support the treatment applied to mitigating the impact of higher cost connections in Scottish Hydro by increasing the incentive rate to £2/kW/year. However this will not be sufficient to address the types of concern raised above. Given the obligation of a DNO to connect a generator, and the move away from “deep” to “shallowish” connection charges that reduces the locational signals, we believe that the risk for DNOs should be reduced further than Ofgem currently proposes. We therefore propose two options for addressing these concerns:

1 DNO-specific incentive rates to offset the risk of connecting higher (but less than four times the average unit cost) cost schemes. As Central Networks West has forecast an average cost of connection that may well exceed those set for Scottish Hydro, we expect to receive a similarly high incentive rate.

2 Increase the floor rate of return to 0.5% below the allowed cost of capital

5.24 – 5.25 O&M costs and the Final Incentive Rate

Ofgem is proposing an O&M charge of £1/kW to cover these costs rather than set an allowance as for other operating costs.

We agree that the figure of £1 per kW per annum seems appropriate for O&M, but this will have to be tested as the market develops. It will be necessary for DNOs to continue to collect O&M charges throughout the life of each DG connection, not just for the ‘commercial life’ of 15 years. It is for consideration what should happen when assets reach the end of their life and require wholesale replacement, rather than repair or maintenance. It is not clear how this would be funded.

5.26 Recovery of the Incentive Rate

Ofgem proposes that the incentive rate should be recoverable only when generators are operating.

We do not agree that the incentive rate should be recoverable only while generators continue to operate. As stated earlier, the success or failure of generators is likely to be a factor of market forces, and completely beyond the DNOs’ control. We believe that the incentive rate should be recoverable in some way, irrespective of whether or not the associated generator lasts for its allotted 15 years.

5.27 Locking in the Incentive Rate

Ofgem will fix the incentive rate applying at the time of connection until the asset is fully depreciated.

We welcome the certainty provided by fixing the incentive rate for the whole 15-year period until the asset is fully depreciated.

5.29 – 5.31 Floor and Cap on DNO Returns

It is proposed that the rate of return will not be less than the allowed cost of debt and will be capped at two times the allowed cost of capital.

The principle of mitigating the risk to DNOs from connecting generators to the network is supported. However, as we have demonstrated above, the risk to Central Networks is considerable, and, in practice, because of the long-run nature of the connections and the uncertainty about future income and costs, it will be very difficult to judge these returns, and it would probably be inappropriate to look at single years or even five year periods in this context.

In our view, these proposals do not go far enough. We believe the floor rate of return should be raised to the allowed cost of capital less 0.5%. Revenue should then be adjusted annually to ensure these returns are achieved, rather than waiting until the time of the next price control review for making such changes.

5.34 'High Cost' Projects

Ofgem will exclude from the hybrid incentive scheme any project that requires direct reinforcement costs in excess of £200/kW and instead require the generator to fund all the additional investment through connection charges.

The principle of excluding high cost projects from the scheme is welcomed. However we believe that the threshold has been set too high, and a more pragmatic approach would be to exclude all projects that result in average costs exceeding double the figure assumed for calculating the 7.5% premium rate of return, i.e. £100/kW.

5.35 – 5.38 Microgeneration

Ofgem are considering whether the same incentive rates should apply to microgenerators.

Customers' interests are best protected if DNOs are incentivised to seek out low cost solutions. We believe this principle should also apply to DG and, consequently, that the incentive should apply to all forms of generation, including microgeneration.

The costs associated with accommodating microgeneration may be negligible where this is very thinly spread across existing networks, but any increased density, and especially clustering, may lead to significant costs. In our view microgeneration will flourish, at least in pockets, and it is therefore very unlikely that the costs of accommodating this class of generation will be negligible. We therefore urge Ofgem to avoid discrimination and set an incentive rate that is applicable across all generating technologies.

5.39 Incentives for Ongoing Network Access

Ofgem has proposed a fixed £/W/hr rebate that is ten times greater than the incentive rate provided for connecting a generator.

Ongoing and reliable network access is an important consideration for all users of a DNO's system. We do not believe that penalties on DNOs for generation-specific access are justifiable or warranted. Access for all users of the network (demand and generation) is already covered by a number of incentives on the DNO (Guarantees of Service, Quality of Supply) and further penalties are unlikely to improve network access.

We therefore continue to oppose the introduction of a rebate for unavailability, especially if the floor rate of return is based on the allowed cost of debt. Instead we believe generators and DNOs should be free to negotiate contracts, which could include compensation arrangements in return for a higher standard of connection.

If Ofgem, in our view misguidedly, is intent on introducing such a mechanism, we believe an efficient level of costs should be allowed for in the price control.

5.41 Definitions and Reporting

Ofgem proposes a reporting framework for DG similar to that used for quality of service.

We are concerned at the potential level of reporting and detailed process work Ofgem may require. DNOs may need to set up detailed processes and possibly IT systems to manage the information. This will inevitably mean one-off and ongoing costs, and these will require funding.

5.47 – 5.53 Innovation Funding Incentive

Ofgem confirms the structure of the IFI proposed in December and proposes development of a good practice guide and open reporting.

We support the concept and proposals put forward in the document regarding IFI.

We would welcome the opportunity to participate in a forum to develop a good practice guide and the best means of sharing findings throughout the industry.

We are also keen to review our present R&D spend for this regulatory year and consider further opportunities.

6. Assessing Costs

6.13 – 6.17 Normalisation of Costs

Ofgem presents its preliminary findings and notes there are still issues to be resolved.

We will be responding under separate cover to the details of the normalisation adjustments made by Ofgem. Here we make some general comments and observations.

Central Networks appreciates that the process of normalisation is required to ensure consistency and comparability between DNOs. However a number of cost items, which have been excluded as part of the normalisation process, are not one-off costs and represent ongoing business costs. These costs should not be excluded when setting income allowances going forward.

We welcome the acknowledgment in paragraph 6.15 that "for the purposes of setting the DNOs' revenue allowances an underlying level of atypical and one-off costs or credits may need to be included in the revenue allowances". Transparency is required on how these allowances are to be calculated.

We believe additional transparency is also required because normalisation is not producing robust results. We believe this is mainly because of different definitions amongst DNOs, but we have no knowledge of the rationale behind the normalisation adjustments for all other DNOs, and therefore cannot compare them to our own, nor can we comment on appropriateness or scale of adjustments included.

The normalisation approach so far has focused on removing atypically high costs, and no adjustment has been made for atypically low costs. This bias will generate unfeasibly low estimates of costs.

Completing a thorough normalisation process in time will be extremely challenging given the significant areas still to be addressed.

Due to issues regarding comparable data, any analysis, which is dependent on identification of frontier companies, is highly likely to produce misleading results. We urge Ofgem to use an average approach or recognise incomparability of data when benchmarking costs, as our more detailed response on benchmarking makes clear.

6.20 – 6.24 Mergers

Ofgem's current thinking is not to adjust DNOs' costs for merger savings for the purposes of benchmarking.

At the last price control, a broad-brush adjustment was made to pass back to consumers the benefit of mergers, which had already taken place. This was based on the assumption that "a sustained reduction of half the fixed costs, such as corporate costs, would arise as a result of distribution companies merging". The policy made at the time was to allow companies to "retain the benefit of merger savings during the five years following the merger".

The merger policy from June 2002 provided a rebate of £32m of revenue over five years to those customers affected by the transaction. This was based on the view that such a merger transaction reduced the number of comparators available to Ofgem, and hence affected the rate of change of the "efficient" frontier.

When the transaction between E.ON and Aquila was being negotiated for the purchase of Midlands Electricity, E.ON agreed to pay the £32m tax, and, in discussion with Ofgem, there was a clear understanding that merger savings would not have to be passed back to customers for five years. This is consistent with the approach taken at the last price control. The merger transaction eventually went through based, at least in part, on the belief that the shareholders would retain any subsequent merger savings created between 16th January 2004 and 15th January 2009.

We are therefore extremely concerned by Ofgem's latest thinking, which has concluded that many of the merger savings are also achievable through other corporate structures. We do not accept that the types of synergies that have been achieved by merging two or more DNOs can be replicated by a single DNO that happens to be part of a wider group and, indeed, your separation rules largely prohibited such activity. There is no opportunity for a single DNO to extract any synergies in distribution-specific functions such as asset management, regulation, work scheduling, MPAS, control rooms, and use of common IT systems and contractors. In contrast, two DNOs that have merged can combine these functions and hence lower average costs, which is why merger transactions between DNOs have continued to take place during the current price control.

From first principles, we believe that Ofgem must ensure that merger benefits for Central Networks are retained for a full five years until Jan 15th 2009. Otherwise companies which have merged since June 2002 will be discriminated against, compared with those DNOs that merged prior to this date.

Not only would companies which have merged since June 2002 incur the £32m merger tax, if future allowances are set on the basis of the comparative analysis, they would also fail to retain the benefits for five years. This is because the regression will be predominantly driven by the cost reduction impact of mergers and the frontier is likely to be set by a merged DNO.

A level playing field must therefore be created for conducting this analysis. We believe this can be achieved by assessing efficiency using nine groups of companies. The scale of each group would be taken into account by assessing efficiency on this basis. An implicit assumption made by conducting the analysis on this basis is that both the merged and non-merged company would be expected to have one fixed cost, which seems a reasonable expectation. Whilst Seeboard merged with EPN and LPN in June 2002, there would not have been sufficient time for the company to have extracted any merger benefits, and so it should be treated separately from the remainder of the EDF group.

An example will help clarify the impact of conducting the analysis under either 9 or 14 companies. If a merged company (A+B) was being directly compared with a non-merged company (C) and was double the size of (C), both groups would be treated as being equally efficient if the merged group had double the variable costs of (C). However, under a 14 DNO regression, company A and B would each have a fixed cost. By implication, its variable costs would be inferred by the regression to be smaller, and hence more efficient than company C, even though this in reality was not the case, as shown by table 3 below.

Table 3 Approach for dealing with merger benefits

Company	Scale	Total costs	Fixed costs set by regression	Variable costs set by regression
Before merger				
A	5	60	20	40
B	5	60	20	40
C	5	60	20	40
After merger (non-group regression)				
A	5	50	20	30
B	5	50	20	30
C	5	60	20	40
After merger (group regression)				
A+B	10	100	20	80
C	5	60	20	40

Total Costs

In addition to conducting any cost efficiency analysis on the basis of 9 groups, we believe that it is important to assess not only operating efficiency, but also total cost efficiency if a more realistic measure is to be ascertained. By total costs, we do not mean simply adding operating costs and capital expenditure together, as this will fail to take account of a number of factors including:

- the contribution of assets purchased in previous periods but still in use;
- the lumpiness of investments that will cause annual fluctuations in capex and hence total cash costs;
- differences in capital stock will drive periods of low and high investment i.e. a DNO with a low capital stock will need to replenish this by higher investment whereas a high capital stock could result in periods of lower investment

We anticipate Ofgem undertaking such rigorous analysis leading up to the publication of the initial proposals in June.

Modelling risk

We have to date not seen any analysis to justify the main drivers of costs affecting the DNOs. Any modelling will be unable to include all these drivers, so we do not believe that it would be possible to argue that all variation from a perceived efficient frontier is explained by cost inefficiency. The adjustment to costs via the normalisation process is also not a complete science. It would therefore be disingenuous to argue that the cost numbers entering the top down models is 100% accurate.

We believe these risks can be mitigated by applying confidence intervals to the analysis. This means that models with a “poor fit” (and hence large standard error) due to insufficient explanatory power would require a larger confidence limit. Consequently we expect Ofgem to present any results using a high degree of probability of at least 90% to demonstrate that all variation from a confidence boundary frontier is due to inefficiency.

Linking Comparative Analysis To Revenue Setting

We continue to be disappointed that Ofgem has not set out how it intends to use the comparative efficiency analysis during this price control review, in particular whether a frontier or average cost approach will be used, and how this will aid the setting of future cost allowances.

We continue to support the strong efficiency incentive of RPI – X, and believe this is best supported by adopting an average cost approach for forecasting future allowances. The average approach will provide reassurance that an unsustainably low cost allowance is not being set, which could otherwise create at the behest of the regulator, significant financial distress within the industry, at a time when investment is required from capital markets to finance higher investment profiles. The average approach will be consistent with market expectations of the cost of capital, which will be based on the performance of the average company. Furthermore, using averages will help to reduce the uncertainty caused by the estimation procedure for normalising costs and the weaknesses of the efficiency models deployed in the analysis.

7. Financial Issues

7.2 - 7.16 Financial Ring-fence

Ofgem clarifies its proposals, in particular the triggers for application of the ring-fence.

We are generally supportive of the proposed criteria for the 'cash lock-up' trigger. However we believe that taking the lower of a split rating as the trigger is disproportionate. It is also inconsistent with our licence obligation to maintain an investment grade rating. This requires a DNO to maintain an investment grade rating from a single agency; i.e. Moody's could mark the DNO as above investment grade, whilst Standard and Poors could grant a sub-investment grade rating.

Therefore we propose that the trigger should not kick in until both rating agencies have marked the DNO at the minimum investment grade or below. Ofgem should, however, finance the price control settlement at well above the trigger level, which we believe to be at an A- credit rating. In addition, we believe that mechanisms for dealing with uncertainty as we have articulated above would help to insulate DNOs from costs shocks.

7.17 – 7.19 The Cost of capital

Ofgem proposes a "vanilla WACC" range of 5.1% to 5.9%.

We note Ofgem's proposed range for the cost of capital.

Maintaining an appropriate level of equity to finance the investment programme will require Ofgem to set a sufficient rate of return, especially since we are competing in a global market for capital. Whilst we welcome the beginning of the necessary debate on the initial cost of capital range, we believe that the capital markets will focus on real world factors such as the long term increase in levels of investment, cash negativity, financeability ratios, the potentially reducing opportunities to outperform the price control as well as comparative rates in other sectors such as water.

In order to attract long-term equity investment to support forthcoming capital programmes, we believe the cost of capital needs to be beyond the upper limit of this range, especially if Ofgem goes ahead with its proposals on incentives, which will reduce the opportunities for out-performance and hence the likely returns on equity investment.

Ofgem's position contrasts with that of the water regulator. Ofwat has stated on numerous occasions that the bottom of its cost of capital range for 2005-10 will be not less than 5%, using a post-tax debt, post-tax equity basis. This is equivalent to the top-end range of the Vanilla WACC reported in the policy paper. It is worth noting that Ofwat has this floor, despite the fact that the risks are probably lower in water given the Interim Determination mechanisms that are in place for dealing with uncertainty, and which currently do not exist in electricity.

Given the above and our own further work on longer-term funding, we would therefore expect Ofgem to set a cost of capital that is at least 5.9% using a Vanilla WACC. This is necessary if the markets are to be persuaded to support the investment programme and we are to avoid ever-increasing debt and gearing levels.

Pensions

Ofgem sets out further thinking on some issues and restates its position on ERDCs.

7.23 - 7.45 Overall

We are pleased to note that Ofgem has taken note of the various discussions and responses to previous consultation papers and removed the threat of a retrospective adjustment to account for previous periods' under- or over-recoveries. Whilst we continue to support the overall aim of the recovery adjustment as it applies to future periods, its application to previous periods would have been unjust and, given the uncertainty as to the allowance given last time, would have required a considerable degree of approximation.

However we note that this proposal is subject to the treatment of Early Retirement Deficiency Cost (ERDCs). Whilst Ofgem has reiterated its desire not to allow any ex post pass-through of these costs, there is no further information provided in the March paper as to how these costs will be treated, and, in particular, the extent to which retrospection is to be applied. The December paper suggested that retrospection should be carried back to the relevant privatisation date, but also indicated that "it is for consideration how far this would be proportionate". We set out in our response to that paper that we believed that the farthest back this principle should be applied is March 2003; effectively the date at which Ofgem first made its intentions on this subject clear. Without this necessary information, we are unable to confirm whether we are satisfied with the overall proposed treatment of pensions, but can only comment on the individual aspects.

7.35 – 7.36 Allocation Between Price controlled and Non-price Controlled Activities

We are generally supportive of the proposals for calculating the allocation between price controlled and non-price controlled activities. However we remain of the belief that pre-1 October 2001 service for Supply employees (past and present) should be included in the allowable liabilities as they were regulated businesses then.

We are concerned about potentially differing methodologies for calculating the pre-privatisation liability, depending upon the extent of information available. This could mean that a DNO that has detailed pension records prior to privatisation could be disadvantaged when compared with a DNO that has no records available and takes a much more simplified approach based on employment costs at privatisation. Given that, at privatisation, most of the RECs had very similar structures, Ofgem should ensure that the allocation of the liability at privatisation produces comparable results across the industry

We look forward to further clarity regarding the allocation of assets, but remain of the view that the most appropriate mechanism is to match them against membership categories.

7.37 – 7.42 Over- or Under-provision

As indicated earlier, we are pleased that Ofgem intends not to make any retrospective adjustment for under- or over-recoveries. We fully support Ofgem's view that an adjustment should be made where pension cost allowances have been too high or too low, but believe that such an adjustment should be via a pass-through mechanism similar to that for the Ofgem licence fee. Ofgem's proposal that the adjustment be made at the following price control review does not provide any protection against potentially significant cash flow issues, nor do we believe that the existing review mechanism is sufficiently transparent to ensure that the adjustment is actually reflected within the final price control settlement.

7.43 – 7.45 ERDC

We continue to have significant concerns regarding the treatment of Early Retirement Deficiency Costs (ERDCs). We believe the costs associated with ERDCs are a legitimate business cost that has delivered substantial savings to end customers. Whether they were paid at the time of the efficiency or deferred via the legitimate use of pension surpluses, they represent a cost that should, at least in part, be passed through to customers. Where the surplus has been used, the deficit that now exists within the scheme should not be reduced by the extent of the ERDC in determining the allowable pensions cost.

As indicated in our last response, we are not able to provide documentary evidence for the expectation that these costs would be allowed. However, the current price control was set in the knowledge that the pension scheme was in substantial surplus. Ofgem set a very small allowance for restructuring costs in the full knowledge that previous surpluses had to be used for something. The use of pension surpluses to finance ERDCs is the most customer-beneficial use of such surpluses. DNOs were right to infer that the cost savings required would in part be financed by this source, because during the Law Lords review of NGC's use of pension surplus, Ofgem did not object to the company funding efficiency savings via this route.

We believe then that there is prima facie evidence that ERDCs should be allowed and that the onus should be on Ofgem to demonstrate that there was any indication that they should not be.

We trust that the next paper will provide additional clarity on this issue and that as realistic and measured an approach is taken with respect to ERDCs as has been with the under- and over-recovery issue, thus allowing for an overall proposal for the treatment of pensions that is fair and acceptable to all parties.

Appendix 3

Developing A RIA for Metering

Introducing competition in metering services, whilst retaining the obligations and price controls on the DNOs, effectively forces DNOs into an exit strategy from metering. The view that the risks on DNOs are mitigated by the opportunity to win business out of area is mistaken. There are no real opportunities for the regulated metering businesses to expand.

The situation that exists is that the DNOs have both metering obligations and a requirement that there is no discrimination in service provision in-area. The contracts let by suppliers tend to be multi-regional and, as Ofgem has taken the stance that DNOs cannot offer competitive contracts in-region, DNOs cannot offer lower prices and so cannot effectively compete. Furthermore, the DNOs are organised and have legacy processes, systems and costs based on providing an in-region service only.

From an industry-wide point of view, the actively-competing metering businesses will be the independent operators currently in the market and possibly separate businesses set-up by distributors or suppliers.

This will lead to substantial changes in the market in the near term, especially as three dominant suppliers have more than 90% of customers in most DNO distribution areas. Such changes are inevitably going to introduce additional costs into the industry. These will include:

- the processes and systems required for transfer of agent;
- additional costs incurred in managing the assets (e.g. asset tracking systems and processes to recover assets from suppliers);
- losses of efficiency – the cost of meter operations is impacted by the geographic density of customers and the introduction of competition will reduce the density and hence efficiencies;
- stranding of assets as suppliers remove meters prematurely or where customer changes of tariff exceed the potential for re-use;
- additional costs and processes for emergency service;
- stranded costs relating to pensions, redundancy payments, property etc. in the DNOs; and
- costs incurred by DNOs to provide the last resort service.

Whilst we do not oppose Ofgem in the introduction of competition in metering, we are of the opinion that it has not been demonstrated that such costs will be offset by any benefits in the electricity industry.

Given the issues discussed above, any metering price control must take account of the stranding of costs and costs incurred in meeting past and future obligations. Such a price control and its associated obligations should be retained for a specific minimum period, e.g. for the next price control period. This will enable DNOs to restructure without significant financial risk.

However, to allow this restructuring, the DNOs must have certainty that, having lost market share through a supplier de-appointing the business, there is no risk that they would have the requirement to ramp-up the services again if the supplier chose to return to the DNO. To ensure that this risk is removed, Ofgem should amend the licence in order that DNOs only retain an obligation to provide metering services to suppliers who have not de-appointed them as meter operator. Such an amendment will reduce the need for DNOs to maintain capabilities against future requirements, but retain protection for both new suppliers and those customers who use a supplier that may be unable to take advantage of metering competition.

Social Impacts

We are of the opinion that the concept of a cap on the differential between charges for prepayment and standard domestic meters in its current form is outdated and unworkable. The DNOs are appointed as an agent of the supplier who has the responsibility to the customer.

The changes in the metering market to date have already made it difficult for DNOs and metering businesses to cap prepayment surcharges. The separation of MAP and MOp and transactional charges has meant that the total cost of prepayment metering services has been driven by the suppliers and their policies with regard to services being requested from the DNOs.

With a separate price control the concept of an overall prepayment metering surcharge cap becomes even more meaningless. Not only is there a potential for MAP and MOp being supplied by different agents of the supplier, but transactional charging and the differing requirement of services by suppliers makes it impossible to impose a cap.

Whilst an overall surcharge cap is unworkable, we would be in favour of specific controls to ensure that prepayment services are price controlled. For MAP we would support a price cap specifically for a ‘basic’ prepayment meter which would allow the DNOs to recover the costs of provision on the same basis as ‘basic’ credit meters. In addition, there should be specific price caps within the MOp price control for ‘basic’ prepayment metering services. Again, these should be reflective of DNOs’ costs.

This approach will ensure that the DNOs’ prices remain non-discriminatory and will enable suppliers to make decisions based on the true costs of providing and operating prepayment meters.

Appendix 4

Developing A RIA for Quality of Service

Whilst we believe an RIA for Quality of Supply (QofS) improvements is beneficial, it must be viewed as one input amongst many into the overall decision making process with respect to justifying the improvements / changes proposed. As we have stated throughout the DPCR process we believe that it will be necessary for Ofgem, in conjunction with the DTI and other stakeholders, to take account of future societal requirements with respect to the outputs required from electricity distribution networks. These outputs will, by their very nature, be both difficult to capture and judge precisely for their financial worth. Consequently, we do not believe they can be adequately represented in a simple cost benefit model. The RIA should therefore be constructed around both quantitative and qualitative approaches.

With respect to the individual areas for the scope of the RIA we comment as follows:

Costs and Benefits

1) Costs and benefits:

- QofS changes: As outlined in the appendix the FBPQ will provide a good foundation to understanding the costs of the proposed changes. However, many of the proposed changes have developed considerably since the FBPQ costs were submitted e.g. the restoration standards and the threshold changes during different storm conditions. It would be impractical at this stage to resubmit more detailed and reflective costs however this should not obviate against further dialogue, preferably at an industry level to ensure that there are reflective costs in the RIA. Finally, although the costs should be quantifiable the majority of the benefits and their monetary value may not. For example, compensation benefits associated with the GS2 storm arrangements can be estimated from past performance, but benefits to customers from, for example, an average CML improvement, even with a willingness to pay survey, will be difficult to judge with any precision or robustness.
- Other costs: In any transparent assessment all other indirect type of costs should be captured. For example, for the “semi-automatic” GS payment systems for GS failures, the cost of transferring payments to suppliers needs to be taken into account. We suggest that a workshop may be the most appropriate forum in which these can be captured and indicative costs agreed.
- Changes to the network for visual amenity reasons: the cost of changing the network to improve its impact on visual amenity was outlined for Central Networks in our preferred scenarios, where we also presented the benefits, albeit in qualitative terms. If Ofgem wish to justify these improvements, which we consider are necessary for Schedule 9 compliance, it would be appropriate to involve relevant stakeholders, e.g. the National Parks, so that a robust RIA can be constructed and agreed.
- Changes to network resilience: similar considerations to those outlined for the amenity changes apply. We believe that the benefits of the outputs bought in terms of network resilience (i.e. improved storm reliability) need to be shaped by strategic societal guidance. We would support a conference or workshop focusing on the requirements from future distribution networks.

2) Impacts

- Safety – In general, it is not considered that the proposed QofS changes have an impact on safety. However, those associated with amenity improvements and network resilience may have consequential public safety improvements from, for example, the replacement of overhead line with either covered conductor or underground cables
- Long term reliability – the proposed QofS improvements will have little impact on the long term reliability of the network as they are unlikely to be delivered through reliability improvements. This is a consequence of the incentive regimes. Delivery of QofS is, we believe, best achieved through a network which is *generally* more reliable. However, this is driven more by long-term investment plans and is a function of asset management practices and the level of capex allowances and efficiency measures in the main price control mechanisms
- Other incentives e.g. rolling capex, rolling opex, DG and losses incentives. Although the incentives have the potential to interact the effect is considered minimal

Distributional effects

We stated, in our response to Quality of Supply proposals, that in terms of network performance we do not believe in discriminating between different groups of customers, except in terms of network characteristics. Quite apart from our obligation not to discriminate, the network itself "does not readily distinguish" between customer groups, which aren't related in some way to the characteristics of the network e.g. rural / urban customers being associated with underground / overhead networks.

The average overall CML/CI incentive regime has tended to favour customer groups fed from overhead networks with the introduction for example of pole mounted auto-reclosers. Whether this trend continues will be dependent on the types of targets set and the underpinning investment as part of the majority price controls. Indeed any future improvements will also involve the urban networks. Although on the surface this may be seen to redress the balance, it could also be improving what is already an acceptable service. The only way to ensure that average benefits are spread amongst customer groups is to allow more focused targets with associated appropriate investments.

Additionally, the storm GS2 will compensate customers fed predominantly from circuits having overhead lines. The compensation costs will however be distributed amongst all customers

Risks and unintended consequences

Mechanisms such as capping financial exposure (either overall or to an individual event) or allowing certain levels of cost "pass through" control the level of financial risk to which the companies are exposed through the QofS incentives. If these were to change as, for example, is proposed with the cost pass-through arrangements for storm payments, then, without any other compensating measure, the level of financial risk will inevitably change.

Additionally, if the rules by which each output is judged change, then again the level of a DNO's risk exposure will change. For example, in the proposed IIP scheme, the probability of receiving a reward or benefit will vary according to the weightings given to the subjective element and mechanistic elements within the force-majeure corrections regime.

Consequently, any proposed cost-benefit analysis needs to take account of the detailed impact on the risk balance if it is to robustly portray the economic signals.

Finally, with all incentives, there is always the risk of unintended consequences. For example, focus on average measures in the IIP regime can drive towards improvements in urban network performance which may not be what is intended. The QofS incentives themselves also drive towards short term improvements or “symptom” fixes rather than giving an incentive to make the network more reliable. It is difficult to prevent an individual incentive driving this unintended consequence and the aim should always be for a balanced portfolio of incentives to mitigate this tendency. Specifically, the longer-term should be balanced with the shorter-term.

Competition
It is not considered that the Quality of Supply measures impact competition.

Reviews and compliance
The costs of monitoring and auditing associated with ensuring consistency in reporting against the revised framework need to be taken into account in the cost benefit model.