JMF/SA

15 August 2003

Mr C Altin
Head of Price Control Development
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Dear Cemil,

ELECTRICITY DISTRIBUTION PRICE CONTROL: INITIAL CONSULTATION – JULY 2003

CE Electric UK Funding Company (CE) is the UK parent company of Northern Electric Distribution Limited (NEDL) and Yorkshire Electricity Distribution plc (YEDL). The views expressed in the attachment to this letter represent the response of CE, NEDL and YEDL to Ofgem's publication *Electricity Distribution Price Control Review: Initial consultation,* July 2003 (68/03).

We are grateful for having the opportunity to comment on this consultation document. In summary our views are:

- The greater part of regulated income should continue to be provided by the RPI-X mechanism. In addition to units distributed and customer numbers some form of capacity driver should be introduced.

- We propose that a standard EHV transportation tariff, combined with an annualised connection charge to recover additional site-specific costs, should be implemented.

- The categories of new connections work that are regarded as contestable should be expanded. Connection costs should continue to be treated as an excluded service. Some non-contestable services could be priced by reference to a fixed schedule of rates.

- We agree that it is appropriate to retain a five-year price control period; the retention period for efficiency gains could be longer than the duration of the price control.

- We note that Ofgem intends to apply the merger policy in force at the time each merger took place. In our case this means:

    - provided the normal operation of the price control gives rise to benefits for customers that equal or exceed £12.5m (shared between the two licensees) there will be no need for Ofgem to make any additional adjustment to pass on a guaranteed benefit that specifically relates to merger savings; and

  - Ofgem would have to take care to ensure that NEDL and YEDL enjoy the full benefits of merger savings until the fifth anniversary of the merger (i.e. until 2005/07).

- Ofgem is right to seek to gain a better understanding of how companies have prepared their capex forecasts.

- Out-turn investment will always vary from any plan prepared more than a year in advance, because that plan will have projected a view of risk that will be superseded by better knowledge at the time the actual investment decision is made.

- The current approach to investment ensures that unnecessary investment is discouraged and that necessary investment is remunerated at the cost of capital. Greater use of output measures to remunerate some investment may have some limited application.

- Only where there is considerable uncertainty about the level of future investment (e.g. distributed generation (DG)) is it necessary to depart from the traditional approach.

- There is no need for Ofgem to introduce additional outputs and incentives regarding the resilience of companies' networks and their effectiveness in restoring customers' supplies following exceptional events. Existing regulatory remedies are sufficient incentives to encourage companies to behave responsibly and effectively and are likely to be superior to attempts to finesse the existing price control drivers to reward and penalise particular behaviours.

- The principle of the rolling RAV mechanism should be retained during the next regulatory period.

- The existing guaranteed and overall standards of performance (GOSPs) regime does not need significant change, except to deal with the practical problem of multiple determinations.

- The work done on disaggregating quality of supply performance may *inform* comparisons between distributors. It cannot, however, be used in isolation to judge the relative efficiency or effectiveness of companies.

- We support the proposed incentive arrangements for DG that will provide premium rates of return for network reinforcement when generators are connected to the network. The baseline return should be set at the assumed weighted average cost of capital (WACC) used to determine the overall allowed income. The £/MW driver should be set to deliver the higher rate of return once generators are connected. DNOs also need to be protected against the risk of a generator ceasing to trade. We suggest that the best solution would be to allow a fixed retention period of five years for the £/MW component after the generator has ceased to trade.

- Incentives to provide ongoing network access could be provided by the introduction of a £/MW driver based on the MWh availability agreed with the generator. The method of calculating the capacity made available could be agreed with Ofgem.

- There is merit in the suggestion that a composite equity return could be used.

- It is appropriate that allowance is made for increased costs due to taxation and that this should be assessed on a company specific basis.

- The allowed cost of capital should recognise the actual cost of embedded debt unless that debt was incurred imprudently.

- The principles that Ofgem intend will govern the recovery of pension costs are broadly sound.

- Companies must not be left in a position where obligations to the pension scheme require them to make up the deficit over a shorter period than has been assumed by Ofgem in the setting of the price control.

Yours sincerely

John M France
Director of Regulation

ELECTRICITY DISTRIBUTION PRICE CONTROL: INITIAL CONSULTATION – JULY 2003

The response from CE Electric UK Funding Company (CE), Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

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ELECTRICITY DISTRIBUTION PRICE CONTROL:
INITIAL CONSULTATION – JULY 2003

The response from CE Electric UK Funding Company (CE), Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

The views of CE, NEDL and YEDL in response to Ofgem's publication *Electricity Distribution Price Control: Initial consultation, July 2003* (the *Initial consultation*) are set out below. The response broadly follows the form of the *Initial consultation* and references to chapters and paragraphs are references to the numbered chapters and paragraphs in that document.

SCOPE, FORM AND STRUCTURE OF THE PRICE CONTROL (Chapter 3)

Structure of the price control / revenue drivers

We agree that the broad structure of the current price control remains appropriate as the basis for future price controls and that most regulated revenue should be captured within the RPI – X price control base revenue adjusted by the appropriate volume drivers.

However, the current units and customer numbers drivers need to be supplemented to meet the challenges of distributed generation (DG), including micro-generation, which will impact on units distributed. Some form of capacity driver may be more appropriate going forward.

In addition, only a small subset of headline areas need to be covered by explicit revenue drivers, including:

- a network losses incentive (see our response to Ofgem's consultation *Electricity Distribution Losses: Initial proposals*; June 2003 (44/03);
- development of the current Information and Incentives Project (IIP) scheme, encouraging headline Customer Interruptions (CI) and Customer Minutes Lost (CML) performance and customer satisfaction;
- a £/MW variable for new connections, both generation and demand. There may need to be some weighted basket, to reflect differences between and within generation and demand. To make this practical, it may be appropriate to retain the £/MWh driver for non-half-hourly (NHH) connections, where records of distribution capacity are less readily available, and apply £/MW only to half-hourly (HH) connections;

- a £/MWh variable for Grid-connected generation displaced, to encourage both reduction in system losses and making capacity available to DG over time. This might be as simple as removing the embedded generation adjustment from the current losses formula, as recently proposed by Ofgem, thereby making the relevant comparison one between energy entering the system from other networks and leaving the system at exit points and distribution system inter-connection points. On such an approach, it seems appropriate to value losses at a level similar to that applied to the renewables obligation, suggesting an aggregate value of £60-70/MWh;
- cost pass-through items (NGC exit charges, licence fee, etc);
- pass-through of connection costs from *all* other networks, ensuring that the costs incurred in getting electricity to the networks of the DNOs are treated identically; and
- excluded services along the lines of the current approach. This area will be simplified by better defining the scope of a distribution business and, specifically, what is included in the main price control (see below).

A key issue in this area is network resilience, i.e. the response of the system under extreme conditions. This is clearly important to customers but, because companies will rarely be tested, cannot readily be measured to facilitate an outcome-based incentive scheme. We suggest that this would be better managed within the core price control.

Scope of the price control/excluded services

It is important to review the scope of the distribution business and, in doing so, review the current list of excluded services. Ofgem define eight categories of excluded services and specifically request comments on EHV charges and on non-contestable connection charges.

EHV charges - We agree that EHV customers should have some regulatory protection but not necessarily through a price control. The current licence requires us to ensure that the path of EHV charges is broadly similar to that of other use of system charges. We are not aware that this has been an area of difficulty for customers during the current price control period.

We agree that (ideally) all users (but in practice all EHV users) should face locational charges on an annualised basis. Recognising users' concerns over the potential for monopoly abuse, we suggest combining a standard EHV transportation tariff (reflecting generic 'deeper' reinforcement costs, rates, exit charges, etc) with an annualised connection charge to recover additional site-specific costs. For most practical purposes, particularly from a user's viewpoint, annualised connection charges and transportation tariffs are indistinguishable. The advantages of this approach are:

- by deferring a proportion of connection charges over the life (or part of the life) of the project the initial impact of up-front connection charges on users is softened;
- the true cost of the connection is still ring-fenced;
- locational signals are still provided to users;
- the costs of providing the connection are correctly apportioned and the inappropriate transfer of costs or risks to other existing users is avoided;
- annualised connection charges are capable of evolution to reflect changing network characteristics and commercial arrangements;
- customers have predictability and transparency with regard to their charges; and,
- simpler tariff structures will improve predictability and transparency and better facilitate competition in the trading of energy from generators.

Where providing assets will benefit existing and future users, then the relevant costs should be apportioned accordingly, subject to a de minimis level. The price control must recognise that distributors:

- are exposed to the risk of having to fund portions of unpredictable, possibly economically unsound investment that results from softened locational signals brought about by a shallower charge;
- will incur higher up-front investment; and,
- face increased risk from bad debt should the project fail.

Non-contestable connection charges - Our view is that non-contestable connection charges should not be price controlled. We recognise that customers may have concerns over these costs because they have no alternative service provider but we are confident that the existing regime provides adequate safeguards. A key safeguard is the prospect of possible determinations. In addition to determination there are a number of other factors that act as natural constraints on non-contestable costs and these are set out below:

- Ofgem has considerable powers to investigate allegation of abuse using its powers under the Electricity Act or the Competition Act;
- independent connection providers and consultants are well aware of market rates for staff and equipment and the reasonableness of our charges; and

- we apply a consistent set of charges for contestable and non-contestable works. As competition is increasing in our area with few complaints about our charges, we are confident that this continuing pressure will ensure that our non-contestable charges also remain reasonable.

We do not believe that the fundamentals of excluded services have changed since the inception of price control in 1990, when it was decided that connection charges should fall outside the main price control.

Price control is appropriate for costs that can be forecast in both volume and unit price to a reasonable degree of accuracy, but this is not the case for the connections activity. The inclusion of connections activity in the price control could therefore introduce unwelcome volatility and significantly increase the risk of under or over-recovery. We believe that it would be difficult to apply price control to most activities that make up the connection charge, including the mains work where excavation and reinstatement costs form the major cost components and can vary significantly between projects. We also believe that non-contestable activities, such as reinforcement and diversions, will also contain a significant element of excavation and reinstatement. Wayleave activity and the obtaining of consents in general may lead us to incur costs with third parties (e.g. legal costs). Design costs may also be difficult to place under price control where system studies are required. The volatility of volumes and unit costs therefore make it difficult to include these charges in a conventional price control.

Recognising customer concerns, we suggest that we should review the scope of contestable activities rather than impose an unduly rigid price-controlled structure on non-contestable services. We have discussed with Ofgem the prospects for widening the scope of connections activities that can be made contestable, particularly in relation to cable jointing. We are arranging a live jointing trial and have been approached by two Independent Connection Providers (ICPs) already wishing to participate.

It may be possible to extend the types of work that may be carried out by new entrants by establishing contractual arrangements whereby they can carry out work on our behalf rather than under the employment of the builder or developer. This may be appropriate for work to divert assets on sites they win, and may also be appropriate for obtaining wayleaves.

In a further development of to the process, we could make certain non-contestable services subject to a fixed schedule of rates agreed with Ofgem, along the lines of the current treatment of the prepayment surcharge. We suggest that this schedule should follow the structure of the tables of indicative charges in our LC 4 statement

Other excluded services - It is worth considering, during this price control review, whether there are other services that should specifically be treated as excluded. Appropriate examples could be unmetered supplies activities, services to embedded distributors and revenue protection. There is also a need to clarify rules around excluded services in the changing world - for instance, if and how top up and standby will apply in respect of micro generation.

Incentive framework

We agree with Ofgem's view that the most appropriate way to protect customers' interests is through the development of incentive regulation to give companies financial rewards for delivering outcomes that are in the interests of customers. Customers will continue to benefit from efficiency gains only if companies are allowed to out-perform the price control and retain an appropriate share of the benefits. It is an essential part of the regulatory framework that out-turn rates of return above the notional cost of capital should be welcomed, so long as they are associated with genuine efficiency and appropriate levels of service. We fully support the work being undertaken to strengthen and balance efficiency incentives and agree that both customers and shareholders should benefit from the performance improvements delivered by enhanced incentive arrangements. The regulatory framework should therefore align the incentives which companies face with the interests of customers and should give companies the potential to earn superior returns for out-performing expectations on cost and performance.

We welcome Ofgem's statement that the best performer is not necessarily the company with the lowest cost. Any benchmarking used to inform the review should take performance and Stewardship into account and companies should continue to face incentives that provide a balance between cost reduction and performance. The development of rolling retention incentives; the information and incentives project (IIP) with its focus on CI and CML, customer satisfaction and medium-term performance; the asset risk management (ARM) survey's focus on stewardship issues; and the guaranteed and overall standards of performance provide an appropriate balance between cost efficiency and outcome delivery.

We agree that it is appropriate to retain a five-year price control period going forward and, with respect to the capex efficiency and the opex efficiency rolling incentives introduced in

DPCR3, we agree with the five-year retention periods from April 2000 and April 2003 respectively. However, this does not mean that incentive retention periods need to be capped at five years. In fact, we believe that a longer period would maximise the benefits for customers and that it is appropriate to review for DPCR4 the relative retention periods between the opex, capex and losses incentive schemes. We recognise that, at the time of publication of the latest consultations, Ofgem could not see any theoretical justification for the retention period being any longer. Since then, however, we have provided a theoretical paper for discussion that suggests that the share of efficiencies returned by the companies should rise to two thirds and welcome Ofgem's proposal to discuss this at the incentives working group.

We welcome Ofgem's acknowledgement that the rolling RAV mechanism as outlined to Ofgem by the Price Control Group seems appropriate. This confirms our understanding of the commitment given in the DPCR3 *Final proposals* that companies will be able to retain for five years the benefits of both the depreciation allowance and the cost of capital allowance for capital efficiencies made during the current period. We believe that these two elements should also be retained in the rolling retention mechanism for capital efficiencies achieved during future price control periods and it is important that Ofgem also publish that commitment. We therefore look forward to the publication of Ofgem's approach to the rolling RAV in October 2003 and also to the prospect of working at this level of detail to develop the mechanism for the rolling opex incentive.

We also welcome Ofgem's clarification that it intends to take a broader view of the link between the rolling capex retention mechanism and the achievement of security and quality of supply obligations. We remain of the view that the rolling RAV benefits will be applied unless Ofgem can demonstrate a failure to meet the *obligations* of a DNO.

QUALITY OF SERVICE AND OTHER OUTPUTS (Chapter 2)

Scope of output measures

Environmental – We welcome recognition of environmental issues as significant investment drivers, and look forward to discussing with Ofgem the levels of investment required to deliver an appropriate level of performance. However, there is no particular need to burden the allowed revenue formula with an explicit driver in these areas. Specific environmental measures such as SF_6 leakage, cable oil leakage, etc are adequately covered by environmental legislation and it is therefore not necessary to introduce further regulation. Responsible companies will seek to have sufficient investment allowed in their business plans to meet these obligations. However, to inform this process Ofgem may wish to understand the environmental policies and procedures that companies have in place. Both NEDL and YEDL operate an EMS conforming to European Standard EN ISO 14001: 1996. The development and certification of our integrated Environmental Management System commits us to focus on sound environmental performance. It enables us to control the impacts of our activities and services on the environment, to be accountable for our environmental policy and objectives and ensures that we remain focused on sustainability and continual improvement.

Storm resilience – We welcome recognition that network resilience, both in responding to outages and avoiding outages in the first place, is an important investment driver. The highly variable nature of these events renders them unsuitable for an explicit incentive mechanism. In assessing the need for investment to improve network resilience, we can identify three related aspects:

- reducing the number of customers initially affected;
- reducing the large number of localised faults that create the 'tail' of customers interrupted for a significant period; and
- restoring supplies to those interrupted in a safe and timely fashion.

We can affect the first category through:

- investing to reduce fault rates, e.g. through overhead line maintenance (in its broadest sense, including refurbishment/replacement); and
- network reconfiguration. The greatest benefit will be realised through increasing the number of EHV infeeds, as these provide the greatest resilience against storms: firm HV busbars with at least one clean underground feeder come a close second, particularly where 20 kV infrastructure is used as the most efficient means of serving sparsely-populated areas.

We can influence the second aspect by renewing those networks that serve relatively small numbers of customers, e.g. undergrounding LV overhead lines and rebuilding all HV light lines to a full EATS 43-40 standard (we suggest that the further benefit of covered conductor would repay the marginal cost of such a programme). It should be noted that these programmes pose a high cost for the benefit they yield: for example, in NEDL alone, there are 5,500 km of light lines that have recently been refurbished but are not at full EATS 43-40 specification.

We can influence the third aspect through further improvements in operational practice.

We remain of the view that the existing regime already incentivises us to desirable behaviours in all three of the above categories and accordingly, there is no need for Ofgem to introduce additional outputs and incentives regarding the resilience of companies' networks and their effectiveness in restoring customers' supplies following exceptional events.

Incentives should, where possible, be balanced such that poor performance is penalised and good performance rewarded. As far as incentives to respond effectively to emergencies are concerned, it is difficult to see how these could be introduced in such a way as to be a balanced set of incentives. In circumstances where large numbers of people are off supply for long periods, there will inevitably be discontent no matter how well the company is performing in restoring supplies. But whether the performance truly merits reward will depend on the difficulties the company faces. A company that performs well in difficult circumstances would deserve a reward but we are not sure that public understanding would be sufficiently well-developed to accept companies receiving rewards in circumstances where some customers were experiencing long periods without electricity. We therefore conclude that Ofgem should rely on the existing powerful incentives to restore supply – i.e. adverse public opinion and the associated scrutiny from government and its agencies; Guaranteed and Overall Standards of Performance (GOSPs) and, ultimately, financial penalties.

In the case where exemptions apply to guaranteed standards, due to the severity of the weather conditions, companies still have strong incentives to perform effectively to restore supplies as soon as possible based on the adverse public and media attention that arises if they do otherwise.

Form of the incentive schemes, targets and incentive rates

For financially-incentivised measures, the appropriate targets and incentive rates should be based on a realistic assessment of the scope for improvement in performance, information on the efficient costs of achieving various levels of performance and customers' willingness to pay. It is important that improvement targets are realistic, that companies are given appropriate funding to achieve the targets and that the investment costs and incentives are commensurate with customers' willingness to pay.

The consultation proposes that, under the IIP incentive scheme, further consideration may need to be given to the treatment of planned interruptions, to avoid perverse incentives to accelerate or delay network investment depending on quality of supply performance to date in a given year. We agree that this would be appropriate, particularly in view of the potential increase in connection activity that will be required to facilitate the increase in distributed generation and the possibility of a major increase in overhead line rebuilding work.

Development of the Guaranteed and Overall Standards of Performance (GOSPS)

The consultation document mentions that some guaranteed standard (GS) payments trigger relatively low compensation payments. However, it is important to put this in context with the value of the annual distribution use of system (DUoS) charge per customer, by comparison with which the payments can be considered to be relatively significant. Payments should penalise but not be punitive. It must be borne in mind also that companies operate under a regime where they also face IIP penalties and financial penalties (for failing GSs) in addition to the actual amounts of GS payments. We believe that all the GSs continue to play a useful role if we consider that their purpose is to recognise the inconvenience caused to the customer by a failure. GSs were not designed to be the primary means by which companies were economically incentivised to meet certain requirements. Nor were they devised to compensate the customer for economic or physical loss. They were designed to be a recognition of inconvenience that results from a failure to perform to a given standard. This purpose remains valid. We would not advocate, in the environment of reducing DUoS charges, that there should be any increase in the guaranteed standard compensation payments. We would also not advocate a tightening of the standards. If failure levels are low that is not a reason for tightening standards. Such an approach would mean that Ofgem's view is to set standards at a level that is predicated upon a certain level of failure and we do not believe this to be the case. This would, in effect, remove the incentive to improve performance if the results of such efforts were tougher targets in the future.

There is also the issue of customers' perception of what 'guaranteed' actually means in the context of GSs. We would consider that a rare 'failure' that was compensated by a payment would be acceptable to the vast majority of customers. However, regular failures, even with compensation, would not. In the latter case customers would interpret 'guaranteed' as meaning the service that DNOs must deliver, and not just a level of service that, if breached, triggers a payment. This issue is particularly important in the context of the 18 hour supply restoration standard (GS2) and the multiple interruption standard (GS2a). For GS2a, under the current standard, except under repeated extreme weather conditions, failures are rare and relatively random with most failures as a result of particularly difficult LV faults. However, there are areas of the rural network that are very close to failing this on a regular basis. In these latter cases, should the standard be tightened to a level where failures become regular, we would come under pressure to reinforce supplies no matter how disproportionate the cost. It is interesting to note that, as part of the recent enquiry into supply quality in North Northumberland, Ofgem supported the company's case that there was a limit as to the investment that could be justified to improve supplies to small groups of customers at the extreme ends of supply networks. A similar situation exists with GS2. At 18 hours, except under extreme weather conditions, failures are rare and random. If tightened to say 12 hours, this would no longer be the case and certain remote rural areas would suffer regular failures. The situation on this issue would be further exacerbated if the current severe weather and force-majeure exemptions on GS2 are restricted.

The consultation also proposes a review of the role of Overall Standards of Performance (OSs) within the outputs framework, including whether it is appropriate to include some of the OSs in the IIP incentive scheme. The OSs provide benchmarking and internal goal targets for important aspects of performance. The league table approach has proved very effective in driving performance up. However, we do not consider it necessary to put income at risk/reward to OSs as, with percentage achievement already in the high 90s, such measures would be extremely volatile.

Automatic payments for GS2 would be possible if companies had connectivity models that accurately recorded the phase connection of all premises. They would then be able to provide suppliers with a list of MPANs for payments to be made to the affected customers. However, this would be a massive investment for the benefit of only a minority of customers. We would therefore continue to advocate that, through the publication of the notice of rights and the sort of incident-specific publicity that we saw last Autumn from energywatch, customers have sufficient knowledge of this standard to enable them to make a claim for compensation if they are affected.

The treatment of exceptional events

We understand that the application of GSs under exceptional circumstances is a problematic area, particularly for Ofgem, if a severe weather event results in the requirement for multiple determinations, a situation that Ofgem clearly finds untenable. Ofgem identifies several weaknesses with the current exemption regime and clearly wishes to put in place arrangements that would strengthen incentives, provide greater clarity to DNOs and customers and be more cost-effective in terms of the application of DNO and Ofgem resources when dealing with these determinations.

We support such aspirations. However, a GS is a level of performance that companies should be able to guarantee[1] under normal circumstances. Payments are made to customers when a company fails to meet an obligation that it really ought to have met. This being so, it is appropriate that there should be exemptions from the obligations that apply when there are exceptional circumstances. The removal of the GS exemption for force majeure would impose material, unpredictable and uncontrollable risk on DNOs. Such a move would place an asymmetric risk on a company's cashflow even if companies were able to recover such costs from customers in general at some future time. The issue therefore is to address Ofgem's concerns without facing companies with increased asymmetric risk.

Interim arrangements

We would not support interim arrangements that involved companies paying all claims irrespective of the exceptional nature of the event, and then having to justify to Ofgem *ex-post* all the claims that would not have been paid under normal exemption rules, for future recovery in the following price control. There are a number of issues with such an approach:

- there is a risk that companies will not be allowed to recover their full costs;
- the level of claims would increase significantly because, under the current arrangement, many customers recognise exceptional circumstances and quite rightly do not make a claim. If customers are allowed or encouraged to claim whatever the conditions this element of reasonableness is lifted from the standard and the number of claims will rise, potentially to very high levels. Automatic payments (if they were possible) would significantly increase the number of payments required;
- such an approach therefore would place a significant cashflow burden on all DNOs, particularly if reimbursement were not achieved until the next price control period;
- it would also ultimately increase the costs faced by all customers, as the increased cost of payments would be spread across the customer base – in effect an insurance premium paid after the event; and
- this proposal would remove the resource problem from Ofgem in terms of the number of determinations that it might have to deal with, but it still would place a significant burden on the DNOs, who would have to prove their right to reimbursement. In this

[1] Except in the case of the GS covering multiple interruptions.

regard, it may be difficult to identify whether payments resulted from failures that were uncontrollable or controllable and could therefore require quite a detailed audit of incidents to establish what the pass-through allowances should be. There would also be a period of uncertainty between the company making the payment and the cost pass-through determination by Ofgem.

The only way that companies would be able to consider accepting the above approach in the interim would be if the reimbursement of legitimate costs were achieved in the same year as the incident via suitable amendment to the price control formula – thus minimising the risk and the cashflow implications. This would require the Ofgem verification of the reimbursement claim to be expedited quickly or for the licence amendment to be made subject to later verification or amendment. We accept that verification of whether payments made should have been exempt from the standard would depend upon:

- whether the event prevented us from restoring supplies in the relevant timescales;
- whether we had taken appropriate steps to design and maintain the network to withstand a reasonable degree of severe weather (e.g. tree-cutting); and
- whether we had taken appropriate steps to restore customers' supplies once they had been interrupted.

Long term solution

The longer-term solution would need to address the above issues to the satisfaction of all parties, and we understand that the purpose of the data currently being collected by BPI / Mott MacDonald is to inform such discussions. That said, it is probably best to defer detailed discussions until the analysis has been undertaken. The key issue from a DNO's perspective is that the longer-term arrangements need to address the level of risk faced by the potential uncertainty of alternative arrangements.

At a higher level there are four options:

- the first option to consider should be to keep exemptions as at present but to introduce a more formal rules-based approach in determining when exemptions should apply. This would assist discussions with customers under the current regime for exemptions and would also reduce the problems of ex ante determinations;
- if exemptions were to be removed in order to eliminate the post-event determinations, then it would be necessary to build into allowed income the additional cost of meeting

the unqualified obligations. The risks involved in providing a blanket incentive – by removing the exemption and allowing an 'expected' average annual cost - seem very high. This does not seem to be a workable way to proceed. A possible alternative would be to seek insurance to cover the cost of the unqualified compensation payments and to allow companies the pass-through cost of the insurance premiums;

- a third option would be to set guidelines on what constitutes controllable and uncontrollable time spent disconnected and to allow exemptions from the 18 hour period by introducing a differential regime that applied a longer period than 18 hours under severe weather conditions. The introduction of a differential regime could still, however, result in the same problems as the current exemption regime, in terms of the potential for customers to challenge the decision to apply the longer period. This could be countered by the publication of more explicit rules to describe when exemptions should apply; and
- a fourth option would be to continue the proposed interim arrangements, whereby companies would pay all claims and then seek to recover these costs, plus potentially other event-specific costs, from all customers by means of an adjustment to allowed revenue, provided that they had taken reasonable steps to mitigate actual interruptions exceeding 18 hours. Again, we would argue that companies should not have to wait until the next price control review to seek reimbursement.

Comparing QoS performance / rewarding frontier performance

The disaggregation work currently being undertaken will inform comparisons between distributors, including the potential scope for improvement. However, on its own, it cannot determine whether gaps exist that could or should be closed. For example, the analysis shows that Manweb and LPN have HV underground networks that perform significantly better than average. This arises from the legacy of closed rings used by the former, and the concentration of effort and investment in HV underground (for want of an overhead line network in which to invest) by the latter. It is far from clear that it is cost-effective for other distributors to follow this pattern.

The disaggregation work increases our understanding of the differences in performance between distributors, and thereby identifies areas for further examination. In turn, that deeper review may reveal scope for process improvements or additional investment. The challenge for the review is to identify scope for:

- genuine efficiencies; and

- cost-effective investment.

It would be improper to use the disaggregation work solely to judge relative effectiveness of management, as what would be cost-effective for one company might not be for another (e.g. urban remote control).

We also have concerns over the data used in the disaggregation: some of the circuit lengths declared seem impossible for 11 kV.

It would also be unduly short-sighted to consider disaggregated performance alone in setting the price/performance balance for the review. Customers judge companies on the basis of the service they receive, effectively the headline figures, not some adjusted number. The key determinant of target improvements must therefore be the unadjusted headline figures.

To illustrate the point, we believe that the weakest link in our service to customers across the North East and Yorkshire is the 20 kV overhead line network in Northumberland and Durham. We intend to put forward proposals to reconfigure this network to deliver significant improvements to those customers, which would be reflected (although diluted by the wider mass of customers) in our headline figures. This investment will not materially affect our adjusted performance, as it moves circuits from one basket to another: all things being equal, the resulting figures would therefore be unchanged.

A better understanding of potential improvement areas, combined with information on customer willingness to pay, should be used to inform the setting of targets for the future price control periods. For companies that are on the ‘frontier’ in terms of quality of supply performance, it should be recognised that the marginal costs of improvement will be higher and this should be recognised in both the targets that are set and in the incentive rates. Companies that are frontier performers should be set lower rates of improvement from 2005 onwards and higher incentive rates for performance beyond those targets.

We agree with Ofgem that defining the ‘frontier’ by assessing performance relative to the 2004/05 targets could be seen as problematic. However, we would not advocate that frontier performance be defined by reference to the rate of improvement over the DPCR3 period, since a company with the largest improvement may still not have caught up to the level of performance of some other companies. Frontier performance can only be defined on a relative basis. However, the disaggregation work will, as noted above, not permit simple comparisons between companies to judge effectiveness of operation and, to date, has only considered performance at 11kV. What matters more for this review is:

- understanding what customers expect from each distributor (which may vary between companies);
- establishing the efficient costs of moving to that point for each distributor (which will vary between companies); and
- allowing the funds to deliver cost-effective improvements for which customers are willing to pay.

Incentives for the speed and quality of telephone response

We support the work being undertaken to improve comparability of the performance of companies in terms of the speed of telephone response. However, if the basis of the measure is to focus on customers who speak to an operator, we have reservations about such a measure becoming incentivised under the IIP. The service that is received by customers is provided by a mixture of automated messaging and contact with operators and, during extensive fault situations, the majority of calls are successfully dealt with by automatic messaging. It is therefore important that the measure (if any) is truly representative of the total service provided by call centres. A measure that was based solely on calls answered by an operator could result in inefficient decisions on how to improve performance in call centres that would preclude investment in technological solutions because that aspect of the service is not being measured. It would therefore not be sensible financially to incentivise such a measure.

An alternative could be to enlarge the customer satisfaction survey to include questions relating to the usefulness of the automated message and the speed with which they received information (both by the automated messaging system and by a human operator). Such an approach may give a better indication of the overall service. However, there are a few issues with this approach. The first is that it would only be possible to survey the people who had spoken to an operator and so the sample would be un-representative of the majority of customers who were satisfied with the automated message. The second is that it is likely that some of the people who waited or redialled for an operator could have been personally dissatisfied with the automated message and so the sample would be biased. However, we believe that the customer's perception of how efficiently their call was handled would be more informative than a mechanistic measure of how fast calls were answered by a human operator. It is therefore worth considering the addition of questions in this area. If, in addition to this, a measure of response time is required, based on the calls answered by a human operator, we would prefer this to be defined as the ‘percentage of calls answered within a certain period of time’ rather than the ‘average time to answer’.

DISTRIBUTED GENERATION (Chapter 5)

Incentives for network access and investment

We support incentive arrangements based on a hybrid approach, such as that proposed, which provides premium rates of return for network reinforcement when generators are connected to the network provided. This in essence is the ‘used and useful’ test proposed in our previous responses.

The key components of this incentive are the rate of return from the investment in the period before generators are connected and the rate ascribed to the £/MW driver. In our paper *Some aspects of investment incentives under RPI-X regulation,* we demonstrated that a rate of return equal to the weighted average cost of capital (WACC) provides no incentive for a company to provide investment in discretionary infrastructure. The paper also demonstrated that the required rate of return for such investment was in the region of 18.55 per cent. We would therefore propose that the baseline return for such investment could reasonably be set at a level equal to the WACC and that the £/MW driver be set at a value that provides the higher rate of return for investment when generators are connected up to the available capacity provided. If the baseline return were less than the WACC, then the £/MW driver would be higher. Another issue is the timing of pass-through of such investment into the RAV.

The key to this revenue driver is that it needs to relate to the ‘amount of distributed generation capacity that is provided with access to the network.’ To ensure that this related to the behaviour of the distributor rather than the generator, this should be based upon signed connection agreements rather than metered volumes. It is important that, once network capacity is taken up by a generator, the MW capacity is locked in to the revenue driver value irrespective of whether the generator outputs up to that capacity.

DNOs also need to be protected against the downside risk of a generator prematurely ceasing to trade. There are a number of options:

- if the base return were equal to the WACC, the £/MW driver could be locked in for the depreciation life of the asset. This would reward the DNO for making the infrastructure available when required and remove any downside risks of events beyond its control;
- if the base return were equal to the WACC, the MW revenue driver could be reduced to zero five years after the generator ceased to trade. This would reward the DNO with a return slightly higher than the WACC for making the infrastructure available when required. The revenue driver would be reinstated if another generator connected, thus providing the DNO with incentives to promote the capacity availability;
- if the base return were less than the WACC, the £/MW driver could be locked in for the depreciation life of the asset. This, again, rewards the DNO for making the infrastructure available when required and removes the downside risks of events beyond its control; and
- if the base return is less than the WACC, the £/MW driver could be locked in for a period of X years to ensure a return at least equal to, but preferably higher than, the WACC.

The simplest solution, and one that would incentivise the DNO to ensure maximum utilisation of the network provided, would be to adopt a base rate of return equal to the WACC and to allow a fixed retention period for the £/MW driver after the generator ceased to trade. This could be set at five years.

Incentives for network operation

Incentives are needed to encourage DNOs to seek to avoid network reinforcement by connecting and contracting with distributed generators and moving towards active management of the network and, once generators are connected, to maximise the availability of the connection. The existing capex incentive mechanism that allows fixed retention of efficiency savings will already provide the required incentive to seek to invest in DG infrastructure rather than traditional network reinforcement, provided that the base rate of return is set equal to the WACC as discussed above. There would be no need for a separate DG-related WACC and, if the DG investment were less than the avoided network reinforcement, DNOs would benefit through the retention of the saving for a fixed period of time.

Incentives to provide ongoing network access could be provided by the introduction of a £/MWh driver based on the MWh availability agreed with the generator. Two issues then arise:

- Assessing the capacity made available; and
- Attributing the change in allowed revenue to the relevant user group.

We cannot *measure* capacity made available but we can calculate it. During the planning process, engineers can assess likely patterns of other users' demand and the capability of the existing (or proposed) system, to assess the available operating envelope for the proposed generator. This is probably worth doing only individually for major (EHV) users, with standard factors applied for HV/LV users. The method of calculation could be agreed with Ofgem.

It seems appropriate to recover this increase in allowed revenue from the users who benefit from the capacity made available. As we propose a tariff approach for all users (with annualised charges for elements of connection costs for EHV users), we suggest that generation tariffs in aggregate should reflect this £/MWh incentive in aggregate.

DNOs may also benefit from the losses incentive through the connection of DG. However, we agree with Ofgem that DG could also increase losses under some circumstances and that further consideration is needed to address the risks that DNOs would bear under such situations. It is difficult to recognise this directly in a balanced incentive scheme: it may be appropriate to permit recovery of the lost revenue through some form of excluded service charge on 'loss polluting' generators.

Innovation funding and registered power zones

We have responded separately to Ofgem's specific consultation on this issue.

ASSESSING COSTS (Chapter 6)

Assessing efficiency and forward costs

We agree that a range of techniques (including total cost, top-down and bottom-up analysis) need to be employed for assessing efficiency and projecting future costs and that a degree of pragmatism needs to be applied in the final assessment of projected costs. We have set out some concerns about the use of comparative efficiency assessments in our response to *Development network monopoly price controls: Initial conclusions,* June 2003, and we have not repeated these observations in this response to the *Initial consultation.*

It is important that the assessment techniques used are transparent and that they are applied consistently between DNOs. It is also important that companies' own forecasts are taken into account in this analysis and, whilst the emphasis should always be on companies justifying their forecasts, the analysis should aim to provide transparency between these forecasts and Ofgem's final projections, if different. The analysis must recognise that efficiency cannot be measured by cost alone and so proper account needs to be taken of the level of service provided by the DNO, the resilience and ongoing integrity of its network and its ability to respond effectively under exceptional circumstances. The analysis should also take into account the additional obligations that impact costs in the next price control period but which are not yet fully apparent in historical costs. Examples of these include lane rentals, and implementation of the Electricity Safety, Quality and Continuity Regulations.

We look forward to the publication of the report commissioned from Cambridge Economic Policy Associates to review the techniques applied at the last price control review and to put forward appropriate techniques for the forthcoming review and we shall comment in more detail about specific techniques at that time.

Asset risk management (ARM)

We have always welcomed the ARM review, and supported its use to inform Ofgem's view of how companies manage their assets.

It is important to note that condition-based approaches affect the authorisation of investment in the short term more than the forecasting of budgets in the medium/long term. That is:

- we set investment for the medium term (up to 5-7 years) according to the risks facing the system (influences upon which include its condition);
- we review our 'nominal asset lives' according to this experience; and
- we prepare a long-range forecast (7-20 years) using age as a proxy for expected condition, with nominal asset lives influenced by the experience of actually renewing assets according to risk.

It is important to note that investment proposed in the corporate plan for future years will not be made if, at the point of committing funds, the risk posed by the assets does not justify it. Thus, out-turn investment will always vary from any plan prepared more than a year in advance, as that plan projected a view of risk which will be superseded by better knowledge at the time.

Total factor productivity (TFP)

We welcome Ofgem's inclusion of total factor productivity in their analysis to assess the scope for future efficiencies. It is important that this analysis recognises that cost increases in line with RPI already include the productivity improvements achieved in the economy as a whole. It is expected that the potential future rate of improvement in the electricity sector will not be significantly different from that expected from the economy as a whole.

Merger Policy

We note that Ofgem intends to apply the merger policy in force at the time that each merger took place in its assessment of allowed income at DPCR4.

In its consultation document on the acquisition by CE of the distribution business of Yorkshire Electricity Group plc (YEG), Ofgem did not state in terms how it would treat the efficiency savings arising from this merger. The text referred to Ofgem's statement in relation to 'previous similar transactions' but did not state that treatment of our case would follow the principles described in previous Ofgem statements.

Although precedent may suggest that NEDL and YEDL will be treated consistently with other companies that have merged, Ofgem did not make clear how this merger, or indeed previous mergers, would be treated because it stated that 'these matters will be considered as part of the next price control'. In responding to that consultation paper CE reserved its position specifically in relation to the treatment of merger savings.

Ofgem has signalled that it expected 'an annual sustained savings of £12.5 million' to be rebated to customers *five years* after the merger. This amount was, according to Ofgem, 'reckoned to be half of the estimated fixed costs of a single distribution business'. Previous statements made by Ofgem suggest that the £12.5 million was the total amount Ofgem has in mind; it would have to be attributed somehow between the two licensees. Ofgem stated that it expected 'in practice the efficiency savings should be greater than this [i.e. £12.5 million] since the incentives to maximise efficiency will have been allowed to operate freely'. Ofgem held out the prospect that the £12.5 million may therefore be 'a minimum cost benefit to customers'. This suggests that, provided the normal operation of a price control review gives rise to benefits for customers which exceed £12.5 million (shared between the two licensees), then there will be no need for Ofgem to make any further adjustment to pass on a guaranteed benefit which specifically relates to merger savings. The statement that the £12.5 million 'constitutes a minimum cost benefit for customers' is consistent with limiting the circumstances in which a special merger adjustment would be required to the circumstances where general efficiency savings (including but not limited to those arising from the saving of any fixed costs) amount to *less* that £12.5 million across the two companies. This view of Ofgem's intent is consistent with the Ofgem statement on the TXU/EdF joint venture, 24Seven.

To be consistent with its declared policy Ofgem would have to take care to ensure that NEDL and YEDL enjoy the full benefits of merger savings until the fifth anniversary of their merger (i.e. until 2006/07).

In the case of the NEDL and YEDL merger Ofgem did not repeat its previous statement that Ofgem would expect TXU and EdF to be at the frontier on both cost and quality of service at the next review. Indeed, given that eleven (perhaps soon to be twelve) DNOs are part of groups that include more than one DNO it is hard to see how it could be reasonable to assume frontier performance in all cases on either cost or quality.

FINANCIAL ISSUES (Chapter 7)

Financing obligations

Financial ringfence

We recognise that there is a balance to be struck between protecting customers and allowing commercial freedom to the companies such that the ring-fence is not a straitjacket. The present requirements for all transactions to be carried out at arms-length, on normal commercial terms, provides an appropriate constraint as do the inability to securitise assets and the need to inform Ofgem ahead of any dividend payments.

The commercial freedom afforded to managers to manage the business may mean that some make mistakes and pay the price. Present arrangements do allow Ofgem to step in when problems arise to enhance the ring-fence in the light of the specific areas of concern. This allows ultimate flexibility, which would be hard to achieve in a set of generic constraints.

Under the present system of regulation the assets of these businesses will always have a value that reflects investors' views of the future cash flows. The assets will therefore continue in existence irrespective of their financial history. It is for bondholders to seek their own forms of protection when negotiating funding at the DNO level taking into account the financial position of the company and the regulatory environment in the round.

We look forward to Ofgem's further thinking being explained in a future consultation paper.

Special administration

Given the nature of the DNOs' obligations we appreciate that there is a case for a special administration regime to cover the extreme case of a financial failure. However, even this needs careful handling. Investors may perceive that a regulator who is aware that there is a special administration regime that will ensure that the assets can continue to be used to deliver electricity may be emboldened to make tougher (perhaps unduly tough) judgements at price control reviews. This, in turn, may affect the investors' perception of the risk involved in the business. The absence of a special administration regime would, by contrast, encourage a regulator towards a more prudent view of the prospects of the regulated business.[2] If special administration regimes are to be a feature of the future regulatory regime (as seems likely) then some allowance needs to be made for the investors' likely perception of the added risk attaching to their investment. The case of Railtrack where the equivalent powers were invoked in circumstances where investors might reasonably have expected a different outcome suggests that this is not merely a theoretical possibility.

Cost of capital

CAPM model - We support the consideration of as many of the relevant issues as possible whilst recognising the difficulty of ascertaining forward-looking data. A composite equity return would be attractive provided it had a robust basis and allowed for the current uncertainties in the market.

Taxation – We support Ofgem's intention to recognise the increased costs due to changes in taxation and to consider the use of company specific tax allowances where appropriate.

Any tax allowances for capex are given over a number of years, the future tax allowances being based on what companies spend today. This value is not indexed up to the year in which the allowance is claimed and therefore the value is not maintained in real terms. It is therefore important that the modelling work allows for the *nominal* impact of the tax allowances, due to there being no indexation of tax allowances.

[2] This is the other side of the coin with respect to Ofgem's argument that the absence of special administration could lead to perceptions of greater reluctance on the part of Ofgem to allow insolvency to occur and therefore to a greater likelihood of price control re-openings. (See Ofgem, *DTI Consultation on Proposals for a Special Administration Regime for Energy Network Companies, Ofgem's Response*, June 2003.)

There is also a need for a mechanism to cover ex-post changes in the tax regime that were not anticipated at the time of the review. This would be relatively easy to achieve and would not adversely affect incentives.

The appropriate financing structure for companies is an issue for management given the regulatory environment. Limiting the retention of taxation efficiencies could impose artificial constraints on gearing levels. This would not seem to be appropriate.

Gearing – We remain reassured that Ofgem are looking to providing a result that would keep companies comfortably within investment grade. We look forward to both Ofgem and the rating agencies publishing their thoughts on what this means for companies. In this connection Ofgem will be aware that rating agencies are becoming more cautious and are expressing concerns about, *inter alia*, the regulatory risk carried by companies as we approach DPCR4. The long term rating of the corporate debt of CE has recently been lowered by Standard and Poors to BBB–. At the same time Standard and Poors lowered its long term ratings on NEDL and YEDL to BBB+ (from A-).

Embedded historic debt – We welcome Ofgem's willingness to consider the merits of specific points made by companies on this issue. We remain of the opinion that there should be an allowance based on the interest incurred on historic debt as part of a prudent financing structure. Alternatively, if lower interest rates are to be assumed then the costs of swapping historic debt to current rates should be allowed. Companies should not be placed in a situation where they are unable to recover the costs associated with decisions that were reasonably made in the circumstances that prevailed at the time.

Regulatory Asset Value

Disposals – We support the proposal to adjust the RAV by the value of the sale proceeds five years after the disposal. This provides incentives to manage disposals efficiently whilst providing protection against stranding assets.

Depreciation – The approach to depreciation needs to consider the longer-term path of costs and revenue, the balance of interests between current and future consumers and the need to ensure that companies can finance their licensed activities. If changes are required we would suggest that, for consistency, the tilting and smoothing of depreciation applied to some companies at the last review be applied to the remaining companies at this review before considering whether there is a need to expense replacement capex (i.e. repex).

Pensions

We welcome Ofgem's proposal to issue guidelines on the treatment of pension costs at forthcoming price control reviews. We shall be submitting a separate detailed response to Ofgem on this issue. In the meantime we set out views below on the principles identified by Ofgem in the *Initial conclusions*.

Broadly speaking we agree with many of the key principles set out by Ofgem in the *Initial conclusions*. We believe that the key points are:

- Ofgem can reduce the scale of the problem over the next regulatory period by giving greater certainty about the ultimate recoverability of the costs from the distribution customer base;
- DNOs (and their predecessors in law) have obligations to employees and former employees that cannot be avoided. These costs must be allowed in full;
- the calculation of the scale of the deficit should use actuarial methods;
- any solution must recognise that allowed income at the last price control review was not determined primarily by reference to the actual costs of the companies and therefore there may be difficulties in adopting a pragmatic solution based on the assumption that the accounting charge in a particular year represents the amount allowed by Ofgem in the price control;
- the criterion for disallowance on the basis of poor investment policies should be 'material stewardship failure';
- there is a case that all pension liabilities that arise from the discharge of statutory duties of area boards or their successors (the public electricity suppliers) should be recovered from the distribution customer base;
- if there is to be any further attribution as between distribution and non-distribution employees or pensioners this must be done in such a way as to recognise the obligations of the scheme to its different classes of member and the assets that it holds with respect to those different classes of member; and
- customers have not yet paid the pension deficiency costs associated with redundancies during the years of surplus. The question of customers 'paying twice' cannot therefore arise at this review.

Capitalisation

We agree that there would be significant advantages in increasing clarity on the financial treatment.

TIMETABLE AND CONSULTATION PROCESS

We welcome Ofgem's update to the timetable and note that there have only been minor changes to that published in March. It would be useful if Ofgem could update this on a monthly basis and firm up the dates within the plan on a rolling basis.

REGULATORY IMPACT ASSESSMENT

It is obviously too early for the regulating impact assessment (RIA) to have any meaningful content at this stage. However, we do support this approach and look forward to the development of the RIA in each forthcoming consultation.