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11 February 2004

Dear Nienke,

ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:
SECOND CONSULTATION – DECEMBER 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: Second consultation,* December 2003'. We are grateful for having the opportunity to comment on this latest update to your thinking. In summary, our views on the issues covered by this consultation are set out below:

Form, structure and scope of price controls

- It is appropriate to continue with the 50% customers numbers and 50% GWh distributed revenue drivers. However, a capacity driver may be necessary in future if there is a significant increase in the number of customers generating their own electricity (combined heat and power (CHP) and domestic combined heat and power (DCHP)). We support the review proposed by Ofgem.

- NGC exit charges should continue to be treated as pass–through; equivalent charges from other operators should also be so treated, and business rates should be classified as a pass-through cost for DPCR4.

- We welcome Ofgem's commitment to continue with some form of rolling adjustment for both opex and capex efficiency savings made in the next price control period and are keen to work with Ofgem to ensure an appropriate balance between incentives and the sharing of benefits between companies and customers when developing a mechanism to be applied from 1 April 2005 onwards. Following our useful discussions on the mechanism for the rolling capex incentive we would welcome similar discussions to determine the mechanism for the rolling opex incentive. For opex efficiencies made in the current price control period, we favour the adoption of a mechanism similar to that used by Ofwat, including the amendment on the treatment of exceptional costs, the amendment to make the retention period an 'additional five years' and the need to reset the incentive mechanism at the beginning of each price control period. We support the paper sent to Ofgem by Mike Boxall on 26 January 2004, on behalf of the ENA price control group, which provides the algebra for such a mechanism.

- Bringing EHV charges within the price control of the distribution network operators (DNOs) could remove the risk that Ofgem's assumptions with respect to EHV revenue turn out to be significantly wrong. However, a price control for EHV revenue would have to be designed on very different lines from the price control applied to LV and HV units distributed. In the event that an EHV customer disappears, the DNO's allowed revenue should only be reduced by the avoided costs related to that customer.

- Non-contestable connection charges should remain outside the price control but the range of contestable activities could be extended. We do not believe that it is necessary to introduce additional customer service standards to support competition in connections but the addition of some performance indicators may be appropriate.

- We have proposed a mechanism for dealing with uncertain cost obligations such that neither DNOs nor customers are exposed to a level of risk that is higher than necessary.

- The incentive properties of the regime must not penalise companies that have submitted reasonable forecasts.

- This is particularly relevant in respect of capital expenditure. We believe that Ofgem must now establish a comparable starting point together with a sliding-scale control around that benchmark that rewards efficient underspend and releases funds for efficient and necessary overspend.

- Provided a comparable starting point can be set for all companies at an appropriate and realistic level, there is nothing wrong with the incentive power of the current arrangements.

- With respect to the separate price control of metering services, we believe that meter asset provision (MAP) can be effectively price controlled but that, due to the rapid development of competition in meter operation, it is not necessary to develop a separate price control for meter operation (MOP).

Quality of service and other outputs.

- Guaranteed standard payments should not be increased.

- We support the proposal for a replacement of EGS2 with two standards; one for normal conditions and one for application during severe weather events. We believe that the latter should be based on the interim arrangements but some consideration may need to be given to the trigger levels. There should continue to be a cap on exposure.

- We do not believe that there should be any change to the standards for large business customers. Such customers generally have a choice regarding the security of their connection and therefore are well enough informed to bear the risk arising from their choice.

- We do not believe that the scope of exemptions from guaranteed standards should be reduced, with the exception of severe weather exemptions where we consider that the current 'interim arrangements' could be included within the guaranteed standards for the next price control period.

- With regard to standards for customers with special medical needs, it may be appropriate to review the standards relating to events affecting a single customer. However, for widespread events it would be difficult to guarantee restoration within the standard and it would be misleading and dangerous to introduce a tighter standard that vulnerable customers might regard as truly guaranteed. Customers with special medical needs must continue to put their own contingency plans in place.

- The incentivised measures within the Information and incentives project (IIP) scheme relating to quality of supply should remain as customer interruptions (CI) and customer minutes lost (CML). The scheme should continue to apply only to metered customers and should not be disaggregated by customer type. We would support the move to a symmetrical scheme but the percentage of revenue subject to penalty or reward should remain at +/-2%. With a symmetrical scheme we do not believe that it would be necessary to introduce deadbands or to move to a rolling average. With respect to the current scheme, we believe that there should not be any change regarding the inclusion of pre-arranged interruptions.

- We believe that the incentives aimed at improving the ability of the network to withstand severe weather are strong enough, particularly with the introduction of the interim arrangements. Codifying these arrangements as a guaranteed standard provides transparency for customers.

- We have no issue with Ofgem introducing environmental monitoring in specific areas other than to note that this area is adequately regulated and monitored elsewhere and such duplication is not really necessary.

Distributed generation

- We agree with the principle of a hybrid incentive scheme and also with the proposed alternative for the level of pass-through. However, we are concerned that the levels proposed for the £/kW driver are insufficient to provide an incentive for us in this regard. The driver should reflect the efficient costs of investment in the case of the networks involved. If a flat rate is to be introduced, then that would inevitably need to rise to the highest common denominator (or else fail to provide an incentive, at least for some companies). Based on our understanding of investment costs on our networks, we would contend that the £/kW driver should approximately be doubled in order to ensure that a sufficient return is available to bring forward the required investment.

- We continue to support enhanced funding for R&D sponsored (but not necessarily executed) by DNOs. Specifically, we welcome the decision to allow retention of intellectual property rights (IPR) and agree that, with retention of IPR, a pass-through rate of around 70% seems appropriate.

- We continue to support the registered power zones (RPZ) concept as a means of encouraging the 'demonstration' of novel techniques, bridging the gap between R&D (encouraged through the innovation funding incentive (IFI)) and 'production' connection of distributed generation (DG) (encouraged under hybrid incentive). However, we remain concerned that the undue restrictions proposed will stifle the very innovation this concept should promote. We also consider that the simplified proposal (namely to have only one grade of RPZ) introduces the prospect of some missed opportunities and removes any incentive for companies to take more modest risks in developing network proposals.

Assessing costs

- We welcome Ofgem's statement that the best performer is not necessarily the company with the lowest cost.

- Normalisation of costs is the biggest challenge with respect to the robust assessment and comparison of companies' costs. It is important that Ofgem is able to normalise costs between companies before undertaking comparisons. If this is not possible on a robust basis, comparative efficiency assessments should not form a key element of the final settlement. We support the intention to use a number of techniques for assessing costs but it is important that the overall approach remains as transparent as possible and that Ofgem focus on the relationship between a company's own costs and the performance that it delivers.

- The merger that brought YEDL within the same group as NEDL occurred in September 2001. We agree with the statement made in Ofgem's October consultation that it should apply the merger policy in force at the time each merger took place in assessing allowed income at DPCR4.

- In the case of NEDL and YEDL, Ofgem will have discharged it commitment to secure benefits of at least £12.5m for customers from the fifth anniversary of the merger without the need to make any further adjustment to the 2002/03 costs of the companies. However, to be consistent with its declared policy Ofgem will need 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).

- Prices should not be set on the basis of frontier costs which are likely to capture the short-run non-sustainable costs of a particular DNO in the chosen year.

- We are doubtful about the use that can be made of total factor productivity analysis to assess the scope for future efficiencies. Indeed, we question whether it is necessary to try to anticipate the efficiency savings that may be made in the next regulatory period. Moreover, it is important to recognise that cost increases in line with the retail price index (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 for that expected from the economy as a whole.

Pensions

- We broadly support the methodology proposed by Ofgem but believe that the following major areas still need to be included:
  - the proposed exclusion of early retirement deficiency costs (ERDCs) from the calculation of surplus and deficits within the scheme fails to reflect the reality of the historical position;
  - pensions costs should reflect all contributions and not just those made to the Electricity Supply Pension Scheme (ESPS);
  - recognition has to be made of the asymmetry inherent within the scheme that means the employer, and hence the DNO, is really liable to cover the full amount of any deficit whilst the members expect to receive an appropriate share of any surplus; and
  - the methodology must allow for the normal workings of the scheme in the case of block transfers of members, such as in CE's 2001 transaction with Innogy plc,

without reference to the historic position of the scheme from which the members are being transferred.

- We agree with the need to isolate the elements of the pension scheme applicable to the DNO.

- We believe that the lack of transparency over pension costs allowed in previous reviews hinders any hindsight review.

Financial Issues

- We agree that there is no need to strengthen the financial ring-fence provisions that are included in companies' licences.

- Investment grade covers a wide range from the highs of AAA+/Aaa1 down to the limit of BBB-/Baa3. In looking to be 'comfortably' in this range we feel it is appropriate to target the single 'A' category. This allows some degree of comfort from external factors which may result in market, or agency, perception being negatively impacted other than as a result of DNO action.

- We welcome Ofgem's recognition that a move to a post-tax cost of capital is desirable but request that Ofgem clarify the specific definition of 'post-tax'.

- We believe that Ofgem should maintain the assumed level of gearing at 50%.

- We would support an adjustment to the allowed cost of capital for NEDL and YEDL in respect of embedded debt costs; such allowance to be subject to Ofgem applying objective tests of prudency.

- With respect to the regulatory asset value (RAV) roll forward we believe that NEDL and YEDL should be treated equitably compared with other DNOs. Our letter of 19 November 2003 to Carl Hetherington on the treatment of fault costs provides further details of what we believe is an appropriate adjustment for NEDL and YEDL.

This is the last formal consultation on policy issues before the publication of the 'policy paper' in March 2004. This latest consultation has covered many issues and, in the process, has also raised many new questions for consideration. We expect that Ofgem will have moved towards an initial decision on most issues by March 2004 but believe that there will inevitably be a need to continue discussion on some outstanding issues post March 2004. As such, we consider that another iteration will be required in some areas before Ofgem is able to come to final policy decisions. It would therefore seem appropriate for the March document to be an initial policy decision document and for Ofgem to aim to close off the policy issues in the July 'Initial proposals' document, after receipt of further comments from DNOs.

Yours sincerely

John France
Director of Regulation

ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:

SECOND CONSULTATION – DECEMBER 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:
SECOND CONSULTATION – DECEMBER 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: December consultation, December 2003* are set out below. The response broadly follows the form of the December consultation.

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

1.1 Revenue drivers

1. We agree that the broad structure of the current price control for distribution network operators (DNOs) remains appropriate as the basis for future price controls and that most regulated revenue should be captured within the RPI – X price control, adjusted by the appropriate revenue drivers.

2. The consultation requests views on the form of the revenue drivers. The current drivers of 50% units and 50% customer numbers were included in the price control to allow for changes in costs driven by load growth. The consultation asks whether there is a need to consider a change to the current revenue driver mix and whether the cost drivers could be better reflected by measures other than units distributed – one option being to consider the introduction of a capacity (MW) driver.

3. We remain of the view that it is appropriate that the form of the price control maintains the current revenue drivers in the same proportions. However, a capacity driver may be necessary in future if there is a significant increase in the number of customers generating their own electricity (combined heat and power (CHP) and domestic combined heat and power (DCHP)).

4. We believe that, as suggested, a review of whether the current revenue drivers are the best proxy for marginal cost increases is appropriate. This assessment should not only consider how well these drivers reflect the additional costs under the current network usage (i.e. predominantly demand) but also under an assumed level of generator

connections. This will provide an indication as to whether the drivers are going to be relevant for the duration of the price control.

1.2 Scope/Excluded Services

1.2.1 NGC exit charges

5. The consultation asks whether it is appropriate for NGC exit charges to remain a pass-through cost on the basis that Ofgem considers that:

- DNOs may be able to influence NGC exit charges; and
- the current treatment of NGC exit charges may distort incentives between the development of connections to the transmission system and development of local distribution networks.

6. Our view is that these costs are not materially within the control of the DNO and, as such, exit charges should continue to be treated as pass-through costs. To the extent that NGC can influence these costs it is appropriate that NGC is incentivised by its own price control regime.

7. We would not advocate the movement of NGC exit charges inside price control on the grounds that:

- the actual charges levied on DNOs have recently reduced, through the implementation of the 'PLUGS' methodology. The remaining charges are a function purely of the value of the connection assets – recovering the depreciation and rate of return etc. NGC needs to service the cost of capital associated with providing the connection. As such, seeking to apply a RPI-X type of efficiency to the costs is not relevant; and
- given NGC's licence requirement to develop an efficient and co-ordinated system and its price control, which includes a high level of incentivisation to ensure that assets are deployed and developed in a cost effective manner, bringing the charges that NGC levies on DNOs inside the DNOs' price control would result in regulating the same set of costs twice.

8. A large proportion of a DNO's NGC charges over a price control period are sunk costs. Improving the incentive properties can only influence *prospective* costs; otherwise it simply acts to confer rewards or to impose penalties in respect of past behaviour. This is not a legitimate purpose of regulation.

9. There might be a case for incentivising DNOs to reduce NGC exit charges if it could be shown that under the current arrangements the DNO is indifferent to these costs and might therefore be recklessly inclined to demand new exit points from NGC's system, irrespective of the engineering need or if NGC was not itself incentivised to be efficient in providing such exit points. Ofgem has not advanced any information that suggests that there has been a problem of a proliferation of GSPs as a result of the current pass-through arrangements. Nor, to our knowledge, has there been a problem about inadequate incentives on NGC to control costs. Indeed, since DNOs will incur significant costs of their own in developing their networks in association with a new GSP, it seems unlikely that DNOs will, in practice be behaving in ways that need to be modified by a change in the price control treatment.

10. We note that when Frontier Economics applied their decision making framework to the DNOs' recovery of NGC exit charges they concluded that introducing incentives into the price control treatment of new GSP exit charges risked bringing perverse incentives to bear in this area. Frontier Economics concluded that:

> 'the scale of … new investment, and the scope for inefficiency, are small. The cost pass-through regime may therefore be an appropriate regulatory response, although Ofgem will obviously want to monitor the costs incurred in any new investment to guard against inefficiency or gaming.'[1]

11. The case that the current treatment of exit charges may somehow distort the incentives between the development of the transmission and distribution networks is, in our view, unsustainable. We believe that the economics of individual generation schemes, driven by their technical requirements, is what drives a particular project to connect to the transmission or distribution networks. At the margin, the current situation will tend to encourage development of the distribution network, as it is likely that the connection costs will be able to be distributed across a range of customers, rather than just the connectee. This is, however, a relatively rare situation due to the technical drivers and therefore is not necessarily material.

1.2.2 Wheeled units

12. As we have discussed in detail a number of times before, costs incurred from interconnections with other DNOs were not properly recognised in the last distribution

price control review and the consultation now recognises this anomaly in which DNOs that incur wheeling services costs currently do not receive a cost allowance.

13. We therefore support the analysis that the treatment of wheeled units should be similar to the current arrangements for NGC exit charges, enabling companies that receive wheeled units to recover the associated costs. Such a treatment would encourage the development of interconnection between DNOs should such connections be more efficient than the development of new or increased connections with the transmission system.

14. The consultation paper recognises that there is presently an anomaly in the treatment of wheeled units compared to NGC exit charges. We agree and we believe that the appropriate solution is for both sets of costs to be treated as pass-through items of the price control regime.

15. However, if Ofgem wishes to treat wheeled units as a controllable cost remunerated by price controlled income it will have to make due allowance for this cost in the cost assessment process. At DPCR3 these costs were, properly speaking, still part of the supply business (a quirk of the initial price control treatment at privatisation). It is time to rectify this either by introducing pass-through status for this set of costs (our preferred solution) or, failing that, by making proper allowance for this cost in the cost assessment process.

1.2.3 EHV charges

16. The consultation indicates that Ofgem will consider whether there is a need to change the treatment of extra high voltage (EHV) charges after a review of such charges has been undertaken across all DNOs. Depending on the outcome of the review, Ofgem anticipate three potential options:

- include EHV charges in the price control;
- continue to exclude EHV charges but for Ofgem to publish guidelines on how EHV charges should be set; or
- provide an obligation on all DNOs to provide information on their EHV charges at regular intervals.

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[1] Frontier Economics, *Developing Network Monopoly Price Controls: Workstream A; Regulatory mechanisms for dealing with uncertainty* March, 2003, p24.

17. We agree that something needs to be done to change the current treatment of EHV charges, although not for the reasons that are set out in the consultation paper.

18. EHV charges have been treated as an excluded service since privatisation. The decision to take EHV outside the price control reflected the facts that EHV charges were asset-specific for individual customers and that it was difficult to create a per unit allowance that could be set alongside the three low voltage (LV) categories and the high voltage (HV) category. Significant changes in EHV customer demand would be likely to generate enormous swings in allowed income (though usually not in the associated costs). Indeed, some companies would have been particularly exposed to the behaviour of one or two major customers.

19. EHV was taken outside the price control because it was easier to prescribe the *principles* on which EHV charges should be set than it was to design a price control that effectively reflected those principles. The EHV customer enjoys the protection of a price determination and most EHV customers are well-informed and effective lobbyists. If there is any evidence that the current price control status is working to their disadvantage we would be surprised that this has not been reflected in some determinations made by Ofgem.

20. However, the problem about EHV lies in the method that Ofgem uses to determine the price regulated component of a DNO's income.

21. At price control reviews Ofgem determines the level of allowed costs needed to run the distribution business efficiently. It then deducts a forecast of excluded services revenue and arrives at the amount of money that must be recovered through the price control.

22. This approach re-introduces the risk that the excluded service treatment was designed to avoid. If a DNO does not receive these levels of income from EHV customers, it will under-recover against Ofgem's cost assumptions. For example, suppose Ofgem assumed that a DNO would receive a total of £20m per annum from two EHV customers. One customer closes its factory. EHV revenues fall by half. Costs fall, but by very little. The DNO is fully exposed to income risk with an asymmetrical ability to respond by reducing costs.

23. The current structure of our EHV charges is such that we recover a share of NGC charges, an apportionment of rates, and the rate of return and the depreciation on the

site specific assets. This ensures that charges are fair and recover the appropriate costs. It also means that we are not carrying a unit-related risk. Nevertheless, the income risk that remains is large.

24. We are not, therefore, opposed to changing the regulatory treatment of EHV income; the purpose of any new treatment should be to flex allowed income by the incremental/avoidable costs that arise from changes in customer behaviour. We would like to work with Ofgem to achieve this outcome.

1.2.4 Non-contestable connection charges

25. The consultation discusses the protection provided to customers with respect to the charges and the quality of service relating to non-contestable connection services. It raises the following thoughts for consideration:

- expanding the scope of contestable connections to include, in the shorter term, greenfield housing estates and, in the longer term, diversion and reinforcement works associated with connections;
- modification to the 25% rule; and
- development of further service standards for non-contestable service activities.

26. We have stated on a number of occasions that we fully support competition in connections and that we are happy to adopt high quality assets installed by suitably accredited independent connection providers (ICPs). Competition is increasing in our distribution services areas and we are confident that our non-contestable charges are cost reflective.

27. We are actively participating in the development of competition. Highlighted below are some of the steps we have taken already and further initiatives that we are progressing. We have:

- restructured our connections business to further support competition;
- established effective points of contact and processes to assist ICPs;
- published a user friendly licence condition 4 (LC4) statement including information in support of competition;
- published competition in connection information for ICPs on our website;
- committed to a live jointing trial during 2004 with three ICPs; and

- actively participated in the DNO group in support of the Ofgem chaired electricity connections steering group (ECSG).

Non-contestable charges

28. We believe that non-contestable connection charges should remain outside price control. Furthermore we believe that any consideration of changes to arrangements for controlling connection charges should acknowledge the different processes and mechanisms that support the three main types of activities: i.e. connections made under section 16 of the Electricity Act 1989, non-contestable connection work and non-contestable adoption tasks.

29. We believe that certain charges for non-contestable connection activities can already be determined by Ofgem.

30. Certain activities are only carried out in support of adoption and adoption is currently not a licence requirement.

31. When considering options for the possible price control of non-contestable connection charges we believe that it is important to acknowledge that certain connection activities are already determinable by Ofgem. Furthermore, there are some activities associated with competition in respect of which Ofgem has other powers.

Extending the range of contestable activities

32. It may be possible to extend the range of contestable activities to include live jointing on greenfield housing estates and we are committed to a live jointing trial during 2004.

33. It may also be possible for ICPs to carry out certain incidental reinforcement works associated with new connection sites and new works associated with diversions and we believe this is worthy of further consideration.

Standards of Performance

34. We do not accept that a range of additional customer service standards are required to support competition in connections. There are many different types and sizes of connections that are successfully controlled under section 16, with only a small number of standards covering specific activities.

35. Performance indicators may be appropriate for the provision of points of connection and design approval for standard low voltage new connections to existing low voltage mains. This would be broadly consistent with some current standards applicable to section 16 work.

1.2.5 Business rates

36. In the consultation Ofgem states that it will review whether DNOs should be subject to some form of incentive to manage the level of rates they are charged after it has more detailed information about the way that business rates will be calculated in future.

37. Our response to the historical business plan questionnaire (HBPQ) asserted that business rates were a non-controllable cost and should be treated as such.

38. Rates are calculated by reference to the formula ‘Rateable Value and Uniform Business Rate (UBR)’. UBR is set by central government and is not negotiable. In addition the Government’s transitional arrangements can affect the calculation. The UBR and transitional arrangement are outside the control of DNOs.

39. With regard to Rateable Value (RV) there is a rating revaluation every five years with the last having taken place on 1 April 2000 and the next due on 1 April 2005. Ofgem will also be aware that the electricity industry has been subject to prescribed assessment up to and including the 2000 revaluation. Notwithstanding the fact that the conventional valuation methodology was adopted by the Valuation Office Agency (VOA) for the 2000 revaluation the assessments were not agreed and appeal rights were denied.

40. With regard to the 2005 revaluation it is the Government’s current intention to remove the industry from prescribed assessment. The utilities rating team of the VOA has been tasked with assessing each DNO’s network for rates. The receipts and expenditure methodology has been adopted which has regard to anticipated income and expenditure over a five year forecast period and, having made due allowance for a tenant’s return, derives a rental value for the rateable network. RV is effectively the rental value as at 1 April 2003 (for the 2005 revaluation).

41. Whilst it is the current intention of the Government to remove prescribed assessment they have retained the powers under the Local Government Finance Act to retain

prescription if they feel it necessary. Therefore, at this stage there is a degree of uncertainty as to whether prescribed assessment will be removed.

42. The 2005 rating revaluation is underway. Information has been provided by the DNOs and the correct interpretation of that data for rating purposes is the subject of on-going discussions with the VOA. In the event that rating assessments are determined by the VOA at unacceptably high levels, provided prescription is not retained, there is the possibility of appeals being lodged. However, such a course is liable to incur significant additional costs.

43. During the life of a rating list, the RV can only be amended to reflect 'material change of circumstance'. Such changes relate to physical changes to the rateable network (mainly cables and ducting). Once the RV has been assessed and/or agreed there is nothing that a DNO can do, short of physically reducing the network, to reduce the rates payable. Any potential for savings is minimal and will depend on the overall capital investment plans for the DNO which are also discussed with Ofgem as part of the price control review. As explained above the rating list is set for a five year period and therefore will last from 1 April 2005 to 31 March 2010. At this stage the revaluation requires a fresh look at the assessment of each network.

44. In summary, we do not believe that rates constitute a controllable cost under the price control regime for the following reasons:

- the only element which is notionally 'controllable' is RV as the UBR and transitional arrangements are set by central Government and are outside the control of DNOs. As far as RV is concerned DNOs have an opportunity to negotiate the level of assessment with the VOA provided appeal rights are allowed. However, there is a statutory basis for RV and the assessment has to adhere to this basis; and
- during the life of a rating list the RV can only be amended by reference to physical changes and the potential impacts are minimal.

1.3 Dealing with uncertainty, new obligations and costs

45. It is clear from the consultation that Ofgem does not wish to adopt the Ofwat approach for dealing with uncertainty, preferring instead to provide comfort in specific areas (e.g. lane rentals) that additional terms will be added to the price control (without reopening the main control) should these costs turn out to be material.

46. Whilst we may agree that the Ofwat approach could be cumbersome we do feel that a more formalised approach should be taken than the provision of comfort letters. The following proposed mechanism would provide such a situation, and would be acceptable to NEDL and YEDL.

1.3.1 Proposed mechanism

47. We believe that it is possible to introduce mechanisms into the price control condition of the licence that offer protection for DNOs and for customers from significant movements in costs over which there is still considerable uncertainty at the time that the price control is finalised.

48. If uncertain costs were to be dealt with under the normal price control methodology:

- the DNO would carry the risk that the level of costs assumed by Ofgem would be too low; and
- customers would bear the risk that Ofgem would have allowed an amount that is higher than is necessary.

49. Our proposed alternative approach would be suitable for cost categories where there is considerable uncertainty at the time the price cap is set, but where greater confidence will emerge in due course. The mechanism would operate by:

- isolating the costs that are to be subject to the alternative mechanism;
- recovering the income relating to such costs in *separate components* of the price control formula (there might be a number of such components dealing with each uncertain cost category); and
- introducing a mechanism into the price control where both DNOs and Ofgem would have an incentive to be reasonable in amending *that component* of the price control to allow recovery of a reasonable level of costs.

50. Under this proposal the main price control would specifically exclude that portion of use of system revenue that related to the supplementary mechanisms dealing with the uncertain costs. This could be done relatively easily. Indeed, the current licence removes from regulated income an amount equal to NGC exit charges. The same approach could be used to confine the main price control to everything that was not governed by:

- the uncertainty mechanism;

- pass-through items (e.g. NGC exit charges); and
- excluded services.

51. The main price cap would, as now, be set on the expectation that it would operate for five years.

52. The next step would be for the licence to set out supplementary price caps dealing with the remuneration of these uncertain cost categories. These price caps would include Ofgem's best estimate (at the time the price control is set) of the efficient level of costs in each of the uncertain categories. (The amount could be set initially at zero if Ofgem seriously doubted whether the cost would arise at all). However, these price caps would have embedded within each of them a right for the licensee to notify Ofgem that the amount built into that particular supplementary price cap at the outset shall be replaced by another amount that corresponds to the costs that the licensee, by notice to Ofgem, states that it thinks is more likely to be an accurate level of the costs that are likely to be efficiently incurred.

53. The supplementary price cap would provide that, on receipt of such a notice, Ofgem could:

- do nothing, in which case the revised amount notified by the licensee would become effective in the supplementary price cap; or
- serve a counter notice on the licensee stating that either:
  - (i) Ofgem considered that the original value should be maintained, or
  - (ii) that Ofgem proposed an alternative value.

54. On receipt of such a counter notice the licensee would be given a certain period of time in which to object to, or to accept, Ofgem's alternative. If the licensee accepted, then the revised Ofgem value would enter the licence. This need not require a full 'modification by agreement'; it could be achieved by providing, within the price control condition, for alteration by notice where both Ofgem and the licensee agreed. If the licensee rejected the Ofgem alternative then the licensee's proposed value (in its original notice) would apply unless Ofgem referred the matter to the Competition Commission.

55. If Ofgem's original cost estimate looked likely to be too generous to the licensee, then a similar mechanism would be needed to bring about a reduction in income compared to

the initial view taken in the setting of the supplementary price cap. In these circumstances the mechanism would work as follows. Ofgem would propose a new value (perhaps after seeking information from licensees or other bodies). The licensee would accept the Ofgem proposal or reject it. If it rejected the Ofgem proposal the licensee could propose its own alternative. Ofgem could then either accept that alternative, leave the amount as it stood or refer the matter to the Competition Commission.

1.3.2 The remit of the Competition Commission

56. This device would encourage both licensees and Ofgem to be reasonable since there would be risks and costs for each side in taking a supplementary price cap to the Competition Commission. However, it only works by including within its terms the right to force a Competition Commission reference at short notice if agreement cannot be reached. In the event of a reference to the Commission the supplementary price cap would continue unchanged until the Commission reported.

57. The *Final proposals* should clearly state that the purpose of separation into supplementary price caps is to isolate these uncertain costs from the main price control, to remunerate these separately and to allow the original assumptions for these terms to be revised if the outturn was, or was likely to be, materially different from the initial assumption. Moreover, the design of the price cap would facilitate the construction of a Competition Commission reference that was confined to the particular price control that governed the uncertain costs over which agreement could not be reached.

1.3.3 Similarities with other mechanisms

58. The mechanism proposed could be looked on as being similar to the underlying legal form of the existing regime. The chief differences are that whereas a licensee has to give eighteen months notice of the termination of the existing control and such notice may not have effect before the fifth anniversary of the effective date of the implementation of the control, the mechanism we propose would have:

- a shorter notice period (but still long enough to allow time for consideration by Ofgem and the Commission); and
- no provision that prevented such notice becoming effective before a certain date.

59. The other principal difference is that instead of disapplying the control it would work by substituting another number for the number set out at the outset. This is not especially important conceptually, or as a protection, but we think it more accurately reflects what the mechanism is trying to achieve.

60. The mechanism also has some features in common with the interim determinations mechanism used in water regulation. We believe that the mechanism we propose is superior because it seeks to deal with variations in single items of cost uncertainty

61. This mechanism could operate in parallel with the current convention where Ofgem puts a statement into the *Final proposals* that it may look kindly on requests to re-open the price control where costs arise from a material unanticipated change of law. It could also operate alongside more formal mechanisms that govern material change of law affecting items of cost that were not contemplated at all when the price cap was set.

62. The mechanism set out above:

- would enable Ofgem to set price controls on the basis of assumed levels of costs (which may be nil) in areas of considerable uncertainty;
- would offer DNOs and Ofgem the opportunity to force a re-consideration of those assumptions as uncertainty diminishes;
- includes within it the protection (for DNOs and for customers) of a Competition Commission reference; and
- maintains most of the incentive properties of price cap regulation in those areas where DNOs can *influence* the level of cost but which are subject to considerable uncertainty when the price cap is set.

1.4 Incentive framework

1.4.1 Fixed retention period for efficiency savings for this price control

63. We agree that it is appropriate to retain a five-year price control period going forward. However, this does not mean that incentive retention periods need to be capped at five years. With respect to the capex and opex efficiency rolling incentives introduced in DPCR3 for efficiencies achieved during DPCR3, we agree with the proposal of a fixed retention period from April 2000 and April 2003 respectively. However, we still believe that a retention period of longer than five years would maximise the benefits for

customers and we have provided a paper for discussion that suggests that the share of efficiencies returned by the companies should rise to two thirds for future price control periods. We believe this provides the theoretical justification for the retention periods being longer than those proposed by Ofgem. It is therefore appropriate that we continue to discuss, for application in DPCR4, the relative sharing factors between the opex, capex and losses incentive schemes and whether these should be addressed by varying retention periods or in some other way.

1.4.2 Rolling opex adjustment

64. For opex efficiencies made in the current price control period, we favour the adoption of a mechanism similar to that used by Ofwat including the improvements proposed in their document in *MD187 A further consultation on incentive mechanisms*. This includes the amendment on the treatment of exceptional costs, the amendment to make the retention period an 'additional five years' and the need to reset the incentive mechanism at the beginning of each price control period.

65. Ofwat is proposing to improve the potential rewards for those companies it considers to be at or close to the efficiency frontier, thereby giving them a stronger stimulus to strive to set new benchmarks for the future. This would be achieved by the use of a multiplier which enhances the incentive allowance by 25 or 50 per cent.

66. We are cautious about the use of such a multiplier until there is much higher confidence regarding the robustness of company comparisons and until it is clear how Ofgem intends to give effect to its recognition that lowest cost does not necessarily mean most efficient.

67. Ofgem indicated in its October 2003 *Update* that the Ofwat scheme is broadly appropriate for DNOs although a number of issues need further consideration. We would welcome further discussions on such a proposed mechanism. In this regard, we fully support the position set out on behalf of all DNOs in the letter and paper from Mike Boxall (in his capacity as chair of the ENA price control group) to Cemil Altin of 26 January 2004.

68. We do not agree that Ofgem should link the incentive to some form of eligibility test as there are other schemes and measures in place, e.g. Information and incentives project (IIP), that carry associated penalties for failure. A further test would introduce double jeopardy.

1.4.3 Rolling capex adjustment – Treatment of overspend

69. We welcome the discussions around the potential treatment of overspend of capital allowances, but seek clarification that this refers to 'special' investment for which an allowance was not made. We assume that the incentive mechanism will prevail where there are differences in expenditure profiling only within a price control period (i.e. overspend against allowance in one year, offset by an underspend in the next). We suggest that any 'special' investment is ring-fenced outside the incentive mechanism and the back dating should include not only the return but also the depreciation allowance to ensure that a company is no worse off compared with the expenditure being incorporated in the regulatory asset value (RAV) straight away.

70. We recognise the concerns expressed by Ofgem over offering the same reward for capital efficiency against a wide range of proposed capital programmes, and support linking the incentive rate to the difficulty of securing efficiencies.

71. There is a range of issues that the capital efficiency incentive might reasonably seek to address, that includes:

- more accurate forecasts from companies;
- investing at the 'right' activity level; and
- reducing unit costs.

72. If we are generally to encourage companies to reduce unit costs and to invest only where necessary to do so, a flat-rate efficiency incentive would be appropriate. That is, any underspend would be rewarded at the same rate, as all underspend would be equally valid. This applies so long as we believe that any efficient underspend is equally difficult to achieve.

73. That is, companies should be rewarded according to the proportion (rather than quantum) of savings they make. The effort required to reduce two otherwise equal programmes by (say) 2% each is largely the same, irrespective of the size of those programmes. In quantum, the potential for reward under the incentive regime therefore needs to reflect the size of the original programme.

74. If all forecasts were equally valid then, regardless of the levels of those forecasts, any efficiencies from them should be rewarded equally. It would only be if there was

concern that not all these forecasts were prepared on the same basis that it would be necessary to do something different.

75. The current Ofgem proposals appear to reflect a concern that all forecasts are not equally valid and therefore that it is somehow easier to generate underspends from some rather than others. We recognise those concerns and agree that, if this were the main driver behind the capital efficiency incentive, then the proposals being contemplated by Ofgem would be appropriate.

76. However, we anticipate that Ofgem may receive objections that such a set of proposals might create perverse incentives, as they would encourage the low spender to make more savings than the high spender. It may be said that such a mechanism may not be in customers' best interests, as it would reinforce both recklessness and inefficiency. That is, the incentives would encourage disproportionately large reductions from plans that might already be only just enough to secure network integrity, yet only small reductions from plans that were already inefficiently high.

77. We admit that such observations might have some force. However, their pertinence lies in the fact that they underline the importance of setting a reasonable starting point for all DNOs. It is too late now to incentivise companies to submit reasonable DPCR4 capital investment forecasts. (The forecasts, reasonable or otherwise, have already been submitted). Whatever Ofgem now do cannot influence *those forecasts*. An incentive mechanism that is directed towards influencing forecasting will at best influence the DPCR5 forecasts. The challenge now is to set allowances on a comparable basis and to reward companies fairly and equally in relation to the out-performance or under-performance of that allowance.

78. It is our understanding that our DPCR4 forecasts may be significantly lower than those submitted by some DNOs. We cannot claim to have the same knowledge of other DNOs' networks that we have of our own. However, we feel very strongly that the incentive properties of the price control regime must not penalise us (relative to other companies) for submitting reasonable forecasts.

79. It seems therefore that Ofgem needs to establish some kind of benchmark against which to assess these submissions. From a comparable starting point Ofgem might then establish some sliding-scale control around that benchmark that, on the one hand rewards efficient underspend and, on the other, releases funds for efficient overspend.

80. This should give us some comfort that we are not reinforcing undesirable behaviour, where spending too little can be as detrimental to customers as spending too much. However, we must remember that the current regime has within it the power to penalise companies that have neglected their networks where that neglect gives rise to breaches of the licence of the enforceable obligations of the Electricity Act 1989 (including the obligation to develop and maintain an efficient network). These enforcement powers are backed by a regime of significant financial penalties. These are important incentives for companies.

81. Bearing in mind these potential adverse consequences of neglect we believe that the current regime is broadly appropriate because it rewards companies that avoid unnecessary investment, but it is appropriate and fair only if the initial allowances are set reasonably for each company.

82. The key therefore is the setting of theallowances, where a number of options emerge, including setting allowances by reference to:

- a proportion of DPCR3 projections;
- a proportion of DPCR3 forecast out-turn investment; and
- some appropriate modelling.

83. Each has its merits, and it might be appropriate to review combining two or all three into a composite benchmark allowance. In setting benchmark allowances against DPCR3, we should provide for some uplift to reflect the consensus for increased investment requirements in DPCR4.

84. Care is needed, as significant uplift from DPCR3 projections or out-turn might be entirely justified. It would be inappropriate to assume that large changes were due entirely to inefficiency or otherwise over-estimating requirements.

85. Having set the incentive, we need to set the rate for funding necessary overspend against these assumptions and rewarding efficient underspend. So long as each is efficient, the marginal rate should be the same in each direction for a given company. As noted above, if companies' own forecasts have influenced the allowances it would be inappropriate to reward companies according to the quantum (rather than the proportion) of efficiencies made, so the rewards available under the incentive should be modified according to the size of the original programme. That is, companies whose

forecasts have led Ofgem to allow a higher projected investment should expect to retain less benefit *per pound saved* than firms with more modest plans.

1.5 Price control for metering services

86. We believe that the principles that we put forward in our response to the initial metering consultation document still hold, namely that:

- meter asset provision (MAP) can be effectively price controlled, which is recognised in this consultation document; and
- meter operation (MOP) does not require a price control due to the rapid development of competition.

87. We recognise, and welcome, the proposed competitive market assessment for metering and believe that it is appropriate to run the development of a price control for MOP in parallel to the competitive market assessment.

88. In respect of the proposed form of the control we are keen to see the development of proposals through the newly established metering working group that will enable a greater degree of clarity on whether an average revenue cap or a price cap is the most appropriate way forward. Whether a price cap or a revenue cap is adopted, the challenge is to design a control that appropriately remunerates a DNO at very different potential market shares. The unit costs of this activity are likely to vary with the market share. The price control, whether price cap or revenue cap, needs to adjust revenue by the avoided or incremental costs associated with changes in the DNO's market share.

89. Our greatest concern is that the timescale for the overall price control process is now very constrained and the dependency of the main price control on an effective metering price control process has not yet been sufficiently factored into the plan. We are therefore very supportive of the approach suggested at the metering working group and look forward to a rapid and satisfactory conclusion.

90. We also welcome the inclusion of the development of the competitive market assessment within the terms of reference of the group and look forward to contributing to this key process.

2. QUALITY OF SERVICE AND OTHER OUTPUTS (Chapter 4)

2.1 Guaranteed and overall standards of performance

2.1.1 GS payment levels

91. We would not advocate, in the environment of reducing distribution use of system (DUoS) charges, that there should be any increase in the amount payable for failure of guaranteed standards (GSs). Nor do we consider it necessary to tighten the existing standards.

92. When GSs were introduced in July 1991, the level of payment for GS2 (now EGS2) failures was £20 for domestic consumers and £50 for others. The present £50 and £100 levels of EGS2 payments are approximately double, in real terms, these original levels. During the same period our DUoS income has been approximately halved. The current penalties therefore represent a quadrupling since 1991 in the value of payments relative to the DUoS income from which profits can be generated to support them. Taking into account also, the tightening that has occurred in the standards themselves (eg 24 hours to 18 hours for EGS2), the current GS regime represents a huge increase in risk relative to a DNO's income.

93. The current £50 payment level for domestic consumers equates roughly to a year's DUoS charge. For small commercial and industrial (<100 kW), the current £100 GS payment is also comparable with annual DUoS. This begs the question as to where else a consumer might effectively obtain one year's free service as compensation for less than one day's failure of service. It is pertinent also in this context to recall the ethos that has been consistently held by Offer and Ofgem since the DPCR review of GSs in 1994 – that payments are intended to provide an element of redress to consumers, but not to compensate for financial loss.

94. We believe that GSs continue to play a useful role. They were designed to be a recognition of inconvenience that results from a failure to perform to a given standard. This purpose remains valid. They were not designed to be the primary means by which companies were economically encouraged to meet certain requirements. Nor were they devised to compensate the customer for economic or physical loss. The payment levels should therefore remain unchanged.

95. 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.

96. 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 relating to the service that DNOs must deliver, and not just to 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 (EGS2) and the multiple interruption standard (EGS2a). For EGS2a, 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, DNOs would come under public pressure irrespective of cost.

2.1.2 Severe weather events

97. The consultation considers the replacement of the existing EGS2 standard on supply restoration with two standards:

- the current standard for normal weather conditions with the trigger points and payment levels unchanged; and
- a standard for severe weather conditions with a later trigger point and payment levels possibly based on the current interim arrangements with exemptions for extreme conditions,

and also the possibility of making EGS2 payments semi-automatic.

98. Companies should not be compelled to stand the cost of GS payments to customers in circumstances that are not within their control, and such situations can clearly arise during extreme weather.

99. There are two main reasons for the need for severe weather exemptions. The first is where the weather conditions are such that it would be unsafe to undertake repair work or where access is impossible. The second is where weather conditions greatly

exceed those for which overhead lines have been designed and as a result exceptional levels of damage occur that take time to repair.

100. With regard to the first of these, we do not and would not ask our staff to work in dangerous conditions. In such circumstances we believe that exemption (e) in the current regulations (expectation of breach of enactment) would also come into play in respect of health and safety legislation. We will not compromise on safety and believe that it would not be in line with Ofgem's general duties to introduce changes that would have the effect of putting financial pressure on companies to encourage staff to work in dangerous conditions.

101. Consideration of the second set of circumstances involves striking a cost-effective balance between:

- the higher cost of more robust networks and the cost of repairs;
- likely penalties resutling from extended interruption times; and
- customer expectations.

We would contend that the severe weather exemption is consistent with the funding of DNOs (and implicitly, the view taken of what would constitute a reasonable customer's expectation).

102. Our experience shows that many customers who experience extended interruptions, irrespective of cause, believe that they should receive payment from their DNO. Although Ofgem's latest survey shows that many customers recognise the difficulties caused by severe weather some would be prepared to pay a little extra on their annual bill to ensure that payment is available for those affected by a failure. We should recognise that if customers are to receive money for interruptions that are not due to the fault or neglect of the DNO then that money must come from the generality of customers.

103. During the ice storm that occurred on New Year's Eve 2003, NEDL applied severe weather exemptions to the existing EGS2 and invoked the Ofgem interim arrangements to pay those customers who were without electricity for over 48 hours. Under these arrangements, customers who were without electricity for over 18 hours but less than 48 hours received no payment. Many of these customers could not understand why they received no payment. Some local Members of Parliament were more vociferous because, as their constituencies covered parts of both NEDL and

YEDL, they noted that some of their constituents within the YEDL area received an 18 hour EGS2 payment because the effects of the storm were not sufficiently severe to require the application of the interim arrangements.

104. The present interim arrangements for severe weather do appear to have an issue relating to the trigger point (i.e. the significant difference between the 18 hours for EGS2 under normal circumstances and the 48 hours under exceptional circumstances) and how these are communicated and applied.

105. We believe that a way forward is to introduce and publicise two standards for EGS2, as proposed by Ofgem in the consultation. The first would be the normal EGS2 set at 18 hours (say EGS2a) and the second would be to convert the interim arrangements into separate published standard (EGS2b) for severe weather with a trigger level at 48 hours.

106. We also believe that it may be appropriate to apply EGS2b in adjacent DNOs where companies are affected by the incident but do not necessarily cross the trigger points.

107. Communication of the two standards and application in adjacent DNOs may address the above issue regarding customer perception. However, if this were not the case Ofgem may wish to consider reducing the trigger level to something less than 48 hours. We would support such a reduction but only provided that this did not increase the risk exposure of DNOs.

108. At the Ofgem quality of supply workshop on 3 February 2004, Ofgem proposed the following:

Materiality	**Standard**
< 2% customers affected	- EGS2 applies
>2% and < 5%	- Interim arrangements apply with payment at 30 hours
>5% and <25%	- Interim arrangements apply with payment at 48 hours
>25%	- Exemption

We would support such an arrangement provided that companies were able to recover 100% of the costs for customers restored between 30 and 48 hours in circumstances where the 2%-5% threshold applied.

109. In addition to severe weather there are other truly exceptional events that are outside the control of DNOs and yet can result in very extended interruptions of supply. Examples are terrorism, war, unlawful or malicious acts by third parties, civil disturbances, nuclear and aircraft accidents etc. We would expect such situations to continue to be exempt from the GSs.

110. We would support the introduction of semi-automatic payments for EGS2. This would mean that those customers who we can identify as having been affected for over 18 hours will be offered a payment. Any other customers who make a valid claim would also be paid as per the current arrangements. There would inevitably be an increase in the number of payments made and there would also be an increase in the cost of administering such a system. Such additional costs would need to be recognised in the company's operating cost allowances.

2.1.3 Protecting business consumers

111. The consultation suggests strengthening the protection afforded to larger business consumers by:

- linking the size of payments to the size of the DUoS bill. (An alternative would be for business consumers to rely, at least to some extent, on insurance);
- introducing specific or revised standards on supply restoration for larger HV customers, with a payment trigger shorter than 18 hours; and
- more than two days notice of a planned interruption.

112. The connections for customers that are greater than 100 kW are normally specifically designed for the needs of the customers concerned, as against those for smaller customers who are served by the general (usually LV) network. As part of the design, these larger customers are given the choice of investing in a higher standard of reliability. We consider that such customers are best placed to balance the costs/benefits of a higher reliability of supply against their business needs. Existing customers can also come back to us at any time to re-evaluate such options. Given this situation we would consider it wrong for such customers to get higher levels of compensation than other non-domestic customers for failures of supply when the trade off between cost and levels of reliability was properly made in their choice of supply system.

113. As an industry we encourage businesses to carry out risk assessments on the impact on their output of loss of supply. Our experience is that lost output (and costs) can run into thousands of pounds for even short duration faults. These amounts can never be recovered from particular business customers' DUoS bills even if the arrangement above was implemented. Standby generation, firm supply arrangements, uninterruptible power supplies and insurance should always be part of the contract discussions when suppliers sign up business customers. Insurance is an individual business's decision and legally it can only be applied for by the particular business.

114. It is undoubtedly a truism that larger customers would like shorter restoration times. However, such customers generally have a choice of the reliability of their supply and are best placed to balance out the costs and benefits against their business requirements. An example of this is a HV customer supplied from a dedicated substation. Customers are given the choice of a firm supply with no interruption on first fault, a cheaper loop-in with automatic changeover where fault interruption times are less than 3 minutes, an even cheaper straight loop-in where fault interruption times are less than 3 hours (i.e. switching time), or a minimum-cost tee-connection where fault repair times can be up to 18 hours. As most opt for the minimum-cost option knowing the risks involved, it would be wrong for these customers to have compensation paid for shorter interruptions.

115. We feel any variation in timescale for particular classes of customer would be discriminatory and would be considered so by the other customers. Our experience is that all customers consider themselves to be a priority case when supply is lost.

116. As stated in our previous submission we support the proposal to provide more than two days notice of a planned supply interruption.

2.1.4 Scope of exemptions

117. The consultation considers the reduction of the scope for exemptions, in particular:

- tightening or removing the exemption for industrial action by a company's employees; and
- clarifying and tightening the exemptions for other exceptional circumstances to exclude the impact of weather from the exemptions.

118. We consider that industrial action by employees should continue to be part of the suite of exemptions. As a business we take all steps to prevent such action and consider, that if it is taken, that it is beyond our control. This can be challenged by Ofgem in any particular situation. Moreover, removing the exemption might alter the industrial relations climate and make the event more likely to occur.

119. We consider that inclusion of the ‘interim arrangements’ as a new GS (EGS2b), as discussed above, would adequately deal with the treatment of failures due to severe weather.

120. We recognise the need to balance risk between customers and DNOs. Where exemptions are removed, or their application is restricted through published *ex ante* guidelines, the costs of an efficient operator (recognising the individual circumstances of each company) in making and administering additional payments must be factored into the price control.

2.1.5 Voltage complaints

121. The consultation states that it may be appropriate to tighten the standards for investigating voltage complaints.

122. Both NEDL and YEDL treat ‘flickering lights’ and ‘very low’ voltage complaints as faults and respond accordingly. This is because ‘flickering lights’ are mostly caused by loose connections, i.e. developing faults, and ‘very low’ voltage is indicative of an open-circuit conductor on the HV distribution system.

123. The only reference we can find to voltage complaints in the customer survey is for business customers. In this the results of the survey may be misleading. Virtually all queries we receive from business customers concerning voltage are in respect of voltage dips caused by faults on the distribution network. If the survey questions had been designed to break down the types of voltage problem, we are certain that the results would have confirmed this position.

124. In these situations there is no point in fitting voltage recorders as they will show nothing (except in the unlikely case of another fault occurring on the distribution system while the recorders are in place). Instead we have to examine fault records to determine which faults might have affected the customer in question and then calculate the probable voltages received by that customer concerned during the faults. Under the

present standard we have only five days to carry out this very detailed and complex analysis and communicate the results to the customer. This is an exceptionally short period for this sort of analysis and it is unrealistic to expect that this can be done in a shorter time.

125. As far as we can tell there are no issues with our current response times for general voltage complaints from domestic customers.

2.1.6 Role of the overall standards of performance

126. The consultation considers whether it would be appropriate to remove all the overall standards and, where appropriate, replace these with data collection and monitoring under the IIP. This would cover:

- the percentage of consumers' supplies that are restored within 3, 6, 12, 18, 24 and 48 hours; and
- the number of consumers that experience more than a specified number of interruptions lasting 3 minutes or more in a regulatory year.

127. We do not consider it necessary or appropriate to include any of the overall standards as 'incentivised' measures within the IIP as, with percentage achievement already in the high nineties, such measures would be extremely volatile.

128. However, the overall standards provide monitoring of important aspects of performance and we would support their inclusion in the IIP returns as a move towards reducing the number of reporting mechanisms. In this regard, it would be appropriate to replace the overall standards with a series of measures reported under IIP.

129. The current standards have existed for many years and are undoubtedly due for review. We would welcome further detailed discussion on the examples given together with others that customers may feel to be appropriate.

2.1.7 Scope of the guaranteed standards

130. The consultation considers whether it is appropriate to revise the scope of the GSs and potentially discontinue those that do not now provide much protection to customers.

131. We would welcome detailed discussion on this proposal which should start with the rationale behind the original standards and whether these remain appropriate. Initially when the standards were introduced we understood that a well managed and

resourced company should fail only in exceptional circumstances and would trust that variation from this philosophy is the subject of detailed discussion and agreement on appropriate funding.

2.1.8 Priority customers

132. The consultation considers whether it would be appropriate to introduce a new or revised GS for certain categories of priority customers (e.g. those requiring special medical equipment) with a shorter restoration target.

133. We do not believe that there is a requirement to tighten the GSs for special medical needs customers.

134. A continuous supply of electricity can never be guaranteed and customers with special medical needs should always take personal responsibility and have a contingency in place. Any tightening of GSs for these customers could wrongly dissuade them from this by giving them the impression that their supply would always get restored within the ‘guaranteed’ timescale.

135. A ‘special medical needs’ standard could sensibly be targeted only at standards where DNOs may fail individual customers, e.g. EGS1 service fuse failures. Only under such circumstances could a DNO target its restoration activities to the specific customer.

136. Different arrangements for ‘special medical needs’ customers would be difficult to apply to EGS2 where, due to the random spread of priority customers, each network fault could include such customers and it may be difficult to get these customers restored before the restoration of the network from which they are supplied.

2.2 Reviewing IIP

2.2.1 Scope of the output measures and financial incentives

137. The existing IIP scheme covers CI, CML, quality of telephone response and speed of telephone response[2].

138. The consultation invites comments on the following proposals:

- monitoring performance experienced by different types of customers (e.g. domestic, priority domestic, small non-domestic (<100kW), medium-sized non-

[2] Speed of response is monitored but not financially incentivised.

domestic (100 kW – 1MW), large non-domestic (1MW+) and unmetered consumers;

- implementation of incentivisation at the disaggregated level ahead of the price control commencing in 2010;
- protecting worst-served customers by measuring:
  - the number of customers experiencing more than x interruptions; and
  - the average number and duration of interruptions for consumers on the 10 worst performing circuits in each DNO area; and
- the formal provision of performance information disaggregated by circuit type.

139. We do not believe that there is a need to monitor performance by different types of customer and disagree with the Ofgem assumption that the costs of such a change would not be significant.

140. As already stated, business customers are best placed to determine the cost/benefit position of higher than normal security of supply. They also gain overall protection from the general CI and CML measures that are part of the current IIP.

141. Unmetered supplies are fed from the same LV networks that supply other customers. As such they enjoy the same level of reliability as all other LV connected customers. It is therefore difficult to see what would be achieved by introducing additional reporting in this area, apart from focussing the mind specifically on public lighting service faults.

142. Our connectivity models do not include information on where unmetered supplies are connected. Adding these would be an exceptionally expensive exercise as there is no existing geographic location information available for these. (For metered customers 'address point' information was available).

143. Disaggregation by customer type has the same problems as are evident for the consideration of automatic GS payments. Although we know where customers are connected to the network (at 95% accuracy for HV and 90% for LV) we do not know to which phase they are connected. Without phase information we cannot accurately correlate individual customers to the faults that have actually affected them. Without this correlation we cannot accurately disaggregate performance by customer type. As we would require phase connectivity information to report accurately in the way

proposed then Ofgem is incorrect in suggesting that the additional costs for this would not be significant.

144. There is no clear, nationally-accepted definition of what is a 'worst-served' customer. This will need resolving before any monitoring is done to determine if this is a viable future measure for IIP. Our own view is that a measure which highlighted a high, sustained level of multiple interruptions over several years would be more appropriate than the annual analysis proposed by Ofgem.

145. Although cruder, monitoring of 'worst-served' customer could be carried out at the HV circuit level. Both NEDL and YEDL use a hybrid measure for 'worst circuits' when determining the circuits that are to be included in the improvement programmes. This measure tries to identify sustained problems and takes into account CI, CML and three-hour interruptions. We would be happy to share the details of the calculations with Ofgem.

146. However, what we do know is that, having carried out this exercise for several years and having improved the worst 20 circuits identified each year, current results of the calculation are starting to approach a random selection. By this we mean that the calculations are starting to throw up circuits that we would not normally consider as being inherently poor, but are only selected by this process on the basis of an unfortunate series of coincidences. Examples of this are circuits that have suffered badly at one particular time because of third party damage.

2.2.2 Form of the incentive for interruptions to supply

147. The consultation introduces the following potential options for consideration:

- moving to a scheme with rewards *and* penalties in each year;
- using deadbands to make allowance for data errors and small variations due to unusual weather;
- determining performance on a rolling average basis rather than on annual performance; and/or
- reviewing the weighting of incentives within the scheme.

148. Provided targets are set in a fair and equitable way across all DNOs, then we would support a symmetrical IIP scheme going forward. The amount at risk should remain at the level of +/- 2% and be symmetrical for each year of the price control. We do have

concerns over the way the current Forecast Business Plan Questionnaire (FBPQ) quality of supply scenarios have been set and would not advocate this methodology for the setting of targets in DPCR4. These concerns were set out in our response to the previous consultation document and are repeated in Appendix 1 of this response.

149. Again, provided the targets are fair and IIP is symmetrical, then there is probably no need for a deadband in the IIP as penalties/rewards from performance volatility should even out over time. This requires the mid-point to be set at a level where the gains in good years balance the losses in the (less frequent) bad years: this would lead to companies gaining in more years than they lose, but staying in balance overall.

150. The same applies to the use of rolling averages. Although these would even out the inevitable annual variability in performance, it would take much longer for companies to recover from a poor year and, equally, following a good year, would weaken incentives to improve further. With a symmetrical scheme, annual targets provide a more immediate incentive to improve and, as such, are what we would support. However, in reporting DNOs' performance, we would expect Ofgem to take into account a longer-term trend in performance and not unduly criticise companies for occasionally falling below annual targets.

2.2.3 Pre-arranged interruptions

151. In the consultation, Ofgem considers that the current IIP scheme may provide a perverse incentive for DNOs to bring forward or defer planned interruptions so as to minimise the interruptions in 2004/05. To address this, the consultation considers the following options:

- rolling forward some planned interruptions into the next period; and/or
- excluding planned interruptions from the assessment of performance in 2004/05 (quickly ruled out by Ofgem).

152. Planned interruptions are part of the present IIP scheme. Under this, companies have been able to balance the costs of reducing pre-arranged interruptions against the costs of reducing fault interruptions to come up with the best economic balance.

153. We are now at an advanced stage of implementation of the construction and maintenance programmes that are going to be delivered in 2004/05. The present IIP rules are one of the factors taken into account in determining these programmes. It is

now too late for changes in the IIP rules to have a significant effect on our 2004/05 construction and maintenance programmes. We would therefore not support any changes to IIP before the end of 2004/05.

154. In the current price control period the downward pressure on pre-arranged interruptions, given additional impetus by IIP, has led to the adoption of useful developments (for customers) such as hot-glove working and hot-tank oil sampling. Without IIP these might not have been economic. It would therefore seem that IIP has a role to play in encouraging a reduction in the level of pre-arranged interruptions.

155. Going forward, present indications are that the level of working on overhead lines will have to increase above current levels. This will inevitably result in an increasing level of pre-arranged interruptions. Tighter safety controls on live working on LV cables may also increase the level of pre-arranged interruptions that are necessary. Provided these factors are recognised in the targets set by Ofgem then it would seem better to keep pre-arranged interruptions in the IIP scheme to ensure there is a continued incentive to reduce them.

2.3 Network resilience

2.3.1 Improving the ability of the network to withstand severe weather

156. The consultation recognises that further work will be needed to identify measures of performance before incentives could be introduced in the area of network resilience. It indicates a number of broad options:

- understanding and defining the statistical relationship between severe weather, faults and the number of consumers interrupted;
- an input based approach (if it proves impractical to develop output measures) including:
  - line construction (such as whether they are underground or overhead and specification of the lines);
  - tree management (for example whether trees are cleared within falling distance and whether branches are appropriately trimmed);
  - maintenance of lines to appropriate standards; and
  - automation of equipment and sectionalisation of circuits; and

- removing exceptional event exclusions from IIP.

157. The performance of overhead lines during extreme weather is the main resilience issue facing DNOs. However, typically, major storms have a repeat frequency of around 20 years in individual areas. At this level of frequency it is difficult to justify the huge expenditure required to upgrade the specification of the lines or to replace them with underground cables. Equally, there is little evidence that customers are willing to pay the cost of funding such investments. As a consequence of these factors, our position is that the wholesale upgrading/undergrounding of our overhead lines at this time cannot be justified.

158. However, we are aware that customers' perceptions in this area may be changing and that they might be more willing to pay at least to start upgrading lines. We await with interest the results of Ofgem's second stage customer survey that might shed some more light on this area.

159. If funding is made available to upgrade lines, then our view is that this should be channelled through to those lines that are the most vulnerable to damage during extreme weather conditions. Our experience is that light-duty lines with small cross-section conductors (less than 50 mm^2) are the most likely to fail during such events. In the FBPQ Ofgem asked for indicative costs of a programme to upgrade lines to an EATS 43-40 specification. In the light of the above point, we chose to respond to this by providing a return based on replacing small cross-section conductor lines.

160. The work already carried out on the correlation of high winds to the level of expected damage is interesting. However, there are many factors that affect the level of damage that can be expected during extreme events. The update paper has mentioned some of the factors, e.g. the direction of the wind, ground conditions at the time (saturated/dry) and whether trees are in leaf, but there are other important factors such as how long has it been since the last storm of the same type in the same area.

161. Wind is only one of the causes of extensive damage to overhead lines, with severe icing being the other. Our own experience is that every ice storm is different, with wind strength, wind direction, temperatures before and during the event and how long the conditions persist all being critical in relation to whether ice forms, where it will form, which lines will be affected and how much damage will be done.

162. Removing the severe weather exemptions from IIP would be an extreme step. Our own recent experience of storms is that single events can generate upwards of 20% of the underlying annual CI and 30% of the CML. Earlier storms (e.g. 1990) accounted for even more. These single events would take performance over the current IIP caps for both CI and CML. This would mean that companies would be exposed not only to the costs of the repairs to the system and any applicable GS compensation payments but also to payment of a further 1.75% of their income as an IIP penalty. As an example, the most recent storm experienced by us (New Year's Eve 2003) could have cost the company in the region of £3m for repairs, EGS2 payments (assuming no exemption) and IIP fines (assuming no exemption). The equivalent figure for the 1990 storm would have been £13m.

163. Despite the potentially high level of costs given above, these have to be compared with the cost of the investments required to reduce the effects of severe weather. In NEDL's case, to replace the most vulnerable lines, the small cross-section ones, with the current minimum conductor size of $50mm^2$, would cost in the region of £165m. It would take the equivalent of the 1990 storm each year for this replacement work to be justified in strictly financial terms.

164. To sum up, even the combination of the cost of repairs and no severe weather exemptions on both IIP and EGS2, could not provide a sufficient financial incentive to upgrade small cross-section overhead lines. This would suggest that the case for significant investment (and therefore explicit economic incentives) on resilience is weak; and we believe that modifying the GS regime through codifying the current interim arrangements will encourage companies both to invest out failures where economic to do so and to respond with an appropriate urgency.

2.3.2 Ability of a company to respond to a severe weather event

165. In the consultation, Ofgem considers the interim arrangements for storm payments to be a first step towards introducing incentives in this area. Other potential options proposed for consideration include:

- financial incentives relating to a restoration profile such that penalties be imposed on companies that fail to beat the targets and rewards paid to those that do. (An example could be number of customers restored within 6, 12, 24, 48 and 72 hours);

- an *ex post* performance assessment could be undertaken based on a number of criteria such as timely mobilisation of resources, management of fault repairs, effectiveness of IT systems; and/or
- removing exclusions.

166. As already stated, our own experience would tell us that every event is different. These differences are particularly relevant to the speed with which customers' supplies can be restored.

167. With respect to the speed of restoration, an important limiting factor is the issue of safety and the inability to commence on-site restoration activities until the weather conditions are safe to do so and until it is possible to gain access safely to the affected area.

168. To give an idea of how variable the above factor makes restoration we have examined recent storms that have affected NEDL:

- December 1997 - very high winds that persisted for about 3 hours, with numerous trees blown down. The winds were too high for work to start and the road conditions were too dangerous to access manual switching points until the storm abated. Road closures due to fallen trees hampered access to the more remote areas affected (percentage still off at 12 hours - 9.6, at 24 hours - 1.7).
- December 1998 - very high winds that persisted for about 3 hours, with numerous trees blown down. The winds were too high for work to start and the road conditions were too dangerous to access most manual switching points until the storm abated. However, as the area affected was more urbanised than that affected by the December 1997 storm, some manual switching was able to proceed even during the storm. Road closures due to fallen trees hampered access to the more remote areas affected (percentage still off at 12 hours - 7.0, at 24 hours - 3.1).
- February 2001 - high winds, very heavy snowfall and severe icing. All main roads into the areas where most damage occurred were impassable for 24 hours. It took a further 24 hours for most side roads to be cleared sufficiently to be accessible to four-wheel drive vehicles. Equally, continued snowfall following the storm prevented the use of helicopters for 24 hours (percentage still off at 12 hours - 17.9, at 24 hours - 2.3).

169. The weather forecasts that we receive are quite good at predicting the general level of poor weather. However, they are not very good at predicting the severity of extreme events. This creates a dilemma for us. On the one hand we could ignore the warning and in all probability not suffer significant damage, but run the risk of being criticised for not being prepared in the rare cases where major damage does occur. Equally, we could take the cautious approach and pre-mobilise resources to cover the possible effects, only to have to stand down staff in the majority of cases when significant damage does not occur. This will obviously lead to higher costs than may prove to have been necessary and create the risk of our being considered inefficient. Should Ofgem introduce incentives in this area, then DNOs would inevitably shift their emphasis further towards pre-mobilising resources and hence DNOs would incur higher costs.

170. Despite the above, we acknowledge the scope for better incentivisation of companies to perform well during extreme weather conditions. We also recognise the calls from interested bodies and customers to improve performance following such events. However, our own experience, particularly with most affected customers, is that they do not criticise the efforts of staff to restore supplies, but aim most criticism at the extent of damage that occurred in the first place. As stated earlier, most damage in extreme events is to lines with small cross-section conductors but, within the present limits of what customers generally are willing to pay, we cannot justify the wholesale replacement of these lines with more robust designs or underground cables. If Ofgem's forthcoming second stage customer survey should indicate that customers want more investment in this area and that they are willing to pay then we would need to review our investment plans.

171. This also suggests that customers' concerns may be better served by encouraging investment to remove the problem before it happens, and that incentives on restoration (above the IIP and GSs) may not be necessary. Should incentives be required on companies' response to severe events then, because every storm is different, we would favour the *ex post* performance assessment route. Although this would be less certain for companies in its outcome than a more prescriptive incentive based on the percentages restored in one or more time periods, we feel this would be the only way in which all of the factors that might have affected restoration could be taken into account. Initially, we accept that inter-company performance comparisons will be limited and this will hamper deriving reasonable benchmarks against which performance can be judged. However, in the medium term, it should be feasible for an understanding of

what is possible to be derived and hence a better judgement made on the adequacy of performance in individual events.

2.3.3 Management of communication during an event

172. The consultation considers the following options for incentivising communication following an exceptional event:

- allowing no exclusions from the general IIP telephony incentive; and/or
- an *ex post* performance assessment based on the effectiveness of call handling, communication with customers, energywatch and Ofgem.

173. We assume that the first point relates to the telephone speed of response trial which was introduced in November 2003. During an exceptional event more calls would be answered by automated message but the speed of response would still be impacted. As an industry it is important that we properly recognise the costs of achieving specific targets under all circumstances without exemption. We believe that, if an incentivised speed of response measure is introduced, that it should allow a reasonable level of exemption during an exceptional event.

174. We believe that the idea of an *ex post* performance is an option that should be explored further. A review of the overall service provided during the event is more important than a figure showing the average speed of response to telephone calls. The Accent customer survey could have a role to play in this regard.

2.4 Incentives for telephone response

2.4.1 Scope of customer survey

175. It is evident that DNOs' performance in the area measured by the survey is converging, with all DNOs offering a high standard of service. However, the key areas where the DNOs are not matching the customers' expectations are in the provision of useful and accurate information. We agree that companies should continue to be monitored and performance published but the financial incentive should focus on improvement in these areas.

2.4.2 Form of the incentive survey

176. The measure for customer satisfaction needs careful consideration. The customer survey scheme will need to be reviewed if DNOs' performance converges towards a

narrow band of performance as this could produce a volatile scheme. We would support the concept of pre-determined targets aimed at improving areas where DNOs are not meeting customer expectations.

2.4.2 Survey bias

177. We agree that customers do have different expectations and we have experienced this phenomenon across the two licensed areas that we manage. Since we combined the Customer Relations Centre for NEDL and YEDL into one operation with the same agents answering calls from both areas it is evident that customer perception of the same service is different.

2.4.3 Automated messaging

178. In the consultation, Ofgem considers whether to include customers that have received an automated response within the scope of the customer survey. We do not think that this is necessary as those customers who are dissatisfied with the message will speak to an agent and subsequently be surveyed. Messaging is designed to peak lop calls by answering thousands of calls. A significant sample size would be required in order to ascertain customer perception. We would also have to make significant changes to our messaging systems as the customer contact data is not captured for customers that listen to an automated message.

2.4.4 Incentive for the speed of telephone response

179. We agree that achieving comparability on this measure could be problematic. Development of the proposed speed of response scheme needs careful consideration to ensure that it does not encourage inefficient investment in levels of service above that for which customers would be willing to pay. Significant improvements would require significant increases in staff levels. Company specific targets would be more appropriate than a relative scheme but the target needs to be set at realistic levels.

2.4.5 Combining quality and speed of telephone response

180. The consultation proposes that an alternative to having a separate speed of telephone response could be to include a question on the survey asking customers to rate their satisfaction with the speed of response. We agree that it would be useful to capture customers' general satisfaction with the speed of response. However, such a measure may not be robust enough for incentivisation due to the relatively small sample size but

could provide an appropriate cross-check when used in conjunction with a speed of response measure.

2.5 Environmental reporting

181. We understand that it is not Ofgem's intention to apply financial rewards or penalties to environmental measures but the consultation asks whether it would be appropriate, in fulfilment of Ofgem's broader environmental responsibilities, to begin to monitor and proved a framework for reporting certain environmental outputs (e.g. management of SF6, solid waste management, control of pollution from oil filled cables and visual amenity, including heritage and landscape).

182. NEDL and YEDL environmental pollution type impacts are monitored and measured, and reported internally and to the MidAmerican group headquarters as UK business platform key performance indicators. Historically, details have also been provided annually to the Electricity Association (industry trade association) to form part of their publicly available industry report. Future DNO contributions to the industry report and DNO environmental performance will be subject to discussions within the newly formed Energy Networks Association (ENA - the trade association successor to the Electricity Association).

183. Where applicable, incidents are also reported to the responsible enforcement authorities as required by environmental law or company policy. Incidents of such significance are subject to a fuller report and agreed corrective/preventive action is monitored until completion (as verified by the appropriate agency).

184. Policy pollution control requirements are specified in dedicated NEDL/YEDL environmental operational control procedures with selected (usually by environmental significance) areas made the subject of detailed improvement programmes.

185. The management of waste, with the associated legal duty of care, is controlled by environmental procedures and is subject to monitoring and measurement, with waste volume details also supplied to the trade association. Our management of the visual amenity (including heritage sites and landscapes) is subject to consultation, agreed operational procedures and selected improvement programmes.

186. External monitoring to the ISO 14001 standard is included as part of the NEDL/YEDL formal environment management system (EMS) specification. This monitoring includes legal compliance, pollution prevention and continual environmental improvement.

187. We have no issue with Ofgem introducing environmental monitoring in specific areas other than to note that this area is adequately regulated and monitored elsewhere and such duplication is not really necessary.

3. DISTRIBUTED GENERATION (Chapter 5)

3.1 The incentive framework for distributed generation

3.1.1 DG Pass-through/incentive rates

188. We agree that the hybrid approach is the most appropriate method to take forward in respect of funding network reinforcement associated with the connection of distributed generation (DG). The issue that remains is whether this simply funds activity or is sufficiently enticing for distributors actively to pursue DG connections.

189. Given that, at this stage of the market's development, there are major uncertainties over the likely costs of connecting DG, a degree of caution seems appropriate. We welcome the hybrid mechanism that balances the benefits to distributors of pass-through with the benefits to users of revenue drivers. We also support the application of a 'used and useful' test through the proposed revenue driver to reward successful schemes.

190. We recognise that the incentive to connect (rather than to invest) and extension of the general incentives to cost efficiency are most important to users. Therefore, we support the use of a revenue driver linked to capacity connected and accept, as a consequence, less than 100% pass-through.

191. We support the application of a 15-year life, as developers inform us that this is generally the maximum useful life of their installations: we also note that the Crown Estate off-shore leases are for the same period.

192. As we have previously noted, a 6.5% return is insufficient, of itself, to encourage companies to invest. The evidence shows that companies tend to underspend assumptions at periodic review, as they do not invest simply to earn the notional return

but instead to deliver some tangible benefit (generally in risk reduction or customer service). This is not neglect, but the virtuous provision of a cost-effective service.

193. Further, changing from the current ‘pay-as-you-go’ arrangements to the situation where we are repaid over time will adversely impact our cashflow. The impact of this on financial ratios, and potentially on the weighted average cost of capital (WACC), must not be ignored.

194. In this context, a guaranteed minimum return of 3.2% at 80% pass-through (let alone 1.4% at 70%) is too low: 90% pass-through gives a more reasonable minimum return of 4.9%, although it dilutes incentives for cost control. It should be noted that significant issues still remain, as the prospect of earning 4.9% will not of itself bring forward investment: indeed, we contend that allowing 6.5% does not bring forward investment unless there are other pressing needs.

195. The proposed return of 5% for successful (if high cost) projects is also too low, not least as successful projects need to generate sufficient return to balance well-intentioned but ultimately unsuccessful projects and give a reasonable return across the portfolio.

196. We hold it to be self-evident that, if a distributor can earn only marginally more than the WACC on a portfolio of generation connection projects, he will not invest significant effort in encouraging DG on to his system. Remedying this requires a significantly higher revenue driver than currently proposed.

197. We note that the capacity release schemes for transmission provide for returns up to twice the WACC: it would be only proportionate to make the same provision under the hybrid mechanism.

198. The ILEX CARDIC report suggests distributor costs of around £55/kW in YEDL and £65/kW in NEDL. Using these figures and an 80% pass-through implies a revenue driver of £2.50/kW-yr. in YEDL and £3/kW-yr. in NEDL, to yield around a 10% return on successful projects at average cost.

199. We do not believe this to be an excessive return in the context of the transmission incentive schemes. For example:

- we would have to reduce the average cost per scheme (that is, total DG connection costs including ‘strategic’ investment over the capacity actually connected) by around £20/kW before we would earn 13%. As this would include the cost of 'unsuccessful' schemes, this would be a challenging target;

- even if we connected 1GW of DG in each of YEDL and NEDL, this would increase our allowed income by only £2.5-£3m pa, plus the pass-through element, in each licensee. This is not a significant figure in the wider scheme; and
- these figures imply DUoS (including O&M but excluding any attribution of wider system costs) of about £8/kW-yr. in YEDL and £9.50/kW-yr. in NEDL. This compares favourably with current demand capacity charges of around £12/kVA-yr. in each licensee.

200. We recognise the legitimate concern that, given the present uncertainty over unit costs, companies might earn returns more than twice the WACC. We would be prepared to accept a cap on the total return on the portfolio to avoid this issue.

201. In terms of implementing the scheme, we suggest that distributors should qualify for the revenue driver on the basis of signed connection agreements, as for the current NGC scheme. We propose not to subtract from this total any capacity relinquished by users, but would offset any future connection agreements that use that same capacity. That is, our revenue should not be reduced by customers' actions, but we would not seek double counting of the same investment if capacity were made available, relinquished, then taken up by another user.

3.1.2 Allowance for DG O&M costs

202. We support the proposal to increase the revenue driver under the DG hybrid mechanism to fund operation and maintenance (O&M) costs. Specifically, we suggest that O&M costs of 1-2% pa of the capital invested, with unit reinforcement costs of £50-120/kW, leads to an additional allowance of £1/kW-yr., as shown in the table below:

		Unit cost (£/kW)	
		50	120
O&M as proportion of capital cost (%)	1	0.50	1.20
	2	1.00	2.40

3.1.3 DG 'other issues' (including incentives for strategic investment and ongoing network access)

203. We recognise the concerns expressed in the consultation paper over making significant allowances for 'strategic' investment against uncertain need. Indeed, our submissions contain no such investment, as we cannot make the case, although we see potential synergies with enhancing the infrastructure behind the 20 kV network in NEDL.

204. Therefore, we agree both that the proposed hybrid mechanism provides a funding route for 'strategic' investment, and that a higher return than currently proposed for general connections is required to bring forward significant investment.

205. It might be difficult to link the success of specific DG projects to 'strategic' investment (almost by definition), limiting our ability to apply a differential revenue driver. We suggest that this supports our case for a generally higher revenue driver for DG connections.

206. This would not be a blank cheque for 'strategic' investment, or any other spend, as reasonable returns would flow only from successfully facilitating DG connection.

207. We note the proposal for a £2/MWh capacity buyback. We suggest that this should apply only where users have requested, and paid for, secure connections. It would not be appropriate to compensate users for unavailability of single-circuit connections.

3.2 Innovation funding initiative (IFI)

208. We contend that an unintended consequence of the current framework is that, because incentives for revenue efficiency are greater than for capital efficiency, there is little encouragement for companies to incur revenue spend on R&D to reduce capital spend. This is particularly acute when considering connections spend, which is largely funded on a pay as-you-go basis rather than over time.

209. Therefore, some enhancement of the current framework is required to stimulate further savings in capital investment on network development. Allowing £1-2m pa to secure ongoing reductions in a capital investment programme currently standing at £200m pa, and likely to increase significantly if DG takes hold, has to be a worthwhile investment by customers for customers.

210. We continue to support enhanced funding for R&D sponsored (but not necessarily executed) by distributors. Specifically, we welcome the decision to allow retention of

intellectual property rights (IPR) and agree that, with retention of IPR, a pass-through rate of around 70% seems appropriate.

211. We agree that there is scope for collaboration on areas of common interest, but companies must remain free to pursue local issues individually: we would also not want the need for consensus across all distributors to delay projects of wider benefit.

212. We agree the value of extending a best practice framework, and will pursue this actively through DGCG/TSG.

213. We anticipate continuing with shared projects through ENA and EATL, such as:

- core membership of the ENA, involving £130k of research and development costs in 2003[3]. In addition we are involved with discretionary projects (such as NaFIRs, DINS, SOPS and NEDERs) which incurred a further £140k during 2003;
- the EATL Strategic Technology programme £100k pa;
- EATL lightning location system; partial discharge user group; and engineering forums £60k pa ; and
- 'health indices', to understand better how condition affects performance, affects risk and drives the need for investment.

214. We believe that best value will be delivered for users by incremental evolution of the system against a clear and robust long-term strategy. We therefore support incremental allowances to support clearly-focussed work on feasibility studies and application (rather than necessarily project) development, to increase the range of technical solutions available to us. Rather than execute a major strategy of network transformation, that we find hard to justify in advance of proven need, we anticipate applying those solutions whenever there is good reason to intervene upon the system, to reduce the overall cost of a high-performance generation-rich distribution network.

215. There are also areas where we might usefully commission work better to understand our system. Some of this will be akin to feasibility studies to establish whether (and, if so how) approaches proposed and/or proved elsewhere might best be applied within our service area. This might include:

- ***distribution transformer tap requirements.*** With the need to prepare the network both to accommodate increasing levels of DG, with consequent impact

[3] Costs are for NEDL and YEDL combined.

on power flow and voltage control, and to maintain the proposed statutory voltage limits, we have to review our HV/LV voltage control strategy. This might include revising our specification for distribution transformers to provide a wider tapping range. We anticipate costs of around £20k for an assessment of these issues;

- ***automatic voltage control.*** Building on the work of TSG workstream 3 and the current trials of state estimation controllers such as GenAVC, we anticipate further work to develop both novel control techniques and to explore their application to our networks (e.g. the longer 20 kV feeders). This could incur costs of £100k, although some might be funded jointly with other firms;
- ***lumped capacitative compensation.*** We have a few discrete large switched capacitor banks to control voltage on the HV system remote from the primary source. Building on our understanding of how these interact with patterns of demand, we might usefully study how these might interact with patterns of generation. As capacitative compensation is generally cheaper than using a wound voltage regulator, this might further reduce the costs of a generation-rich distribution system. Detailed case studies might cost around £20k;
- ***distributed capacitative compensation.*** Building on the project above, there is the option of going to a simpler and smaller pole mounted installation with multiple units along the feeder to give enough compensation. The innovation will come in the control of these. We envisage a PMR controlling the capacitor bank via a built in AVC relay (it could take us 2 to 3 years to get to production with costs in the region of £250k). We might also usefully study how these might affect power factors, and hence the marginal impact on primary reinforcement;
- ***modelling severe weather impacts.*** The local incidence of severe weather (wind, ice, lightning, etc.) and its impact on asset types (e.g. the degree to which given icing events affect HV OHL with .017/.025, .05 and .1 sq. in. conductor). This would help us define, and prioritise implementation of, any investment programmes that might be required to enhance network resilience (£50k);
- ***pole design.*** developing a new wood pole design for 66 and 33 kV OHL to replace existing steel mast lines (lattice and girder) on the same span lengths. This would reduce wayleaves issues compared to the use of our current standard wood pole designs, which require much shorter span lengths, and thereby improve efficiency (£200k);

- ***rural automation feasibility studies.*** Feasibility studies for urban and rural automation schemes and subsequent evaluation of non standard technological products. These will include communication systems, control systems, ground mounted and pole mounted switchgear (£50k);
- ***switchgear developments.*** Evaluation of compact outdoor EHV switchgear incorporating disconnectors, earth switches, circuit breakers, CTs and VTs within one SF6 chamber. Benefits will include reduced installation time and lower lifetime maintenance costs, but these need to be assessed to ensure system compatibility and that operational safety issues are not compromised (£30k);
- ***substation developments.*** Evaluation of 'Compact' primary substations, whereby the equipment currently contained within a primary substation building is supplied from the manufacturer within a fully equipped container. The container is located on prepared foundations and cabled up to outgoing circuits, reducing installation times and hence overall costs (£30k);
- ***defects analysis.*** analysis of product defects which occur with in-service distribution assets. These investigations provide improved intelligence on the operational and performance criteria of products utilised within the system operations and are normally outsourced (£25k);
- ***specifications.*** preparation of specifications by external bodies where the core skill no longer resides within the company (£40k);
- ***improved diagnostic tools.*** expanding the application of improved diagnostic tools, such as partial discharge mapping or dissolved gas analysis (£30k); and
- ***improved investment planning tools***, such as those for:
  - demand/generation forecasting (£50k); and
  - assessment of risks and benefits across the investment portfolio (£50k).

216. We expect some of these to progress to demonstration stage under registered power zones (RPZ), e.g. the use of distributed capacitative compensation.

3.3 Registered power zones

217. We continue to support the RPZ concept as a means of encouraging the ‘demonstration’ of novel techniques, bridging the gap between R&D (encouraged through IFI) and ‘production’ connection of DG (encouraged under hybrid incentive).

However, we remain concerned that the undue restrictions proposed will stifle the very innovation this concept should promote, e.g.:

- we cannot develop ‘novel network designs’ when constrained by P2/5;
- distributors will generally be unwilling to trade network support from DG for conventional ‘wires’ reinforcement when still exposed to IIP and GSs and overall performance standards; and
- the proposed bi-annual tender round could cause unacceptable delay to customer-driven projects (as most of these should be).

218. We welcome Ofgem’s willingness to listen to specific requests for relaxing the rules on a case-by-case basis. This supports our contention that the RPZ concept should be a loose framework for relaxing the normal rules, where justified and where appropriate safeguards are provided, to allow us to try something different. This can apply only to individual schemes.

219. We suggested earlier that the revenue driver be enhanced to provide a meaningful incentive on distributors, with a potential cap to avoid excessive returns. The same principle applies here: we support Ofgem’s proposal that the revenue driver for RPZs be twice that for general developments, or £5/kW-yr. for YEDL and £6/kW-yr. for NEDL (plus £1/kW-yr. O&M allowance). Given that there is a proposal for a cap on the cash level of the premium for RPZs, this could readily be extended to ensure that companies do not earn in excess of twice the WACC on any project.

220. Strong incentives are essential for companies to develop new solutions, particularly as these might carry higher risk. For example, the RPZ allowance should bring forward novel schemes to increase system availability at relatively low cost. Should the scheme fail, which is a credible risk for a demonstration project, there remains the issue of who bears the consequences:

- does the generator accept the reduced availability?
- does the generator fund reinforcement to achieve the original design availability?
- does the distributor fund reinforcement to achieve the original design availability, likely leaving some investment stranded and earning only the ‘production’ DG funding?

- Notwithstanding these issues, should RPZs be founded on reasonable revenue drivers with scope for relaxing standards, we will continue to strive to bring forward viable proposals.

221. We suggest that the rewards available from RPZs should not be rigidly structured around a single revenue driver (for example, instead retaining the three-layer scheme previously proposed). During the individual review of each scheme, we suggest that a revenue driver be agreed proportionate to the risk and the total return. That is, we would secure both sufficient reward for the company (a 'collar' on the rate of return) and protection for customers (a 'cap' on the rate of return).

3.4 Regulatory impact assessment

222. First, it is important to separate the proposed hybrid DG funding mechanism from the innovation funding incentive (IFI) and RPZ:

- the former is the only method currently on the table for funding DG reinforcement, and should therefore be seen as an essential component of the price control settlement: without this mechanism, or something similar, we breach the requirement to fund distributors' activities; and
- the latter two clearly involve additional funding by customers, for which they reasonably expect some additional benefit. The RIA should therefore focus on these areas.

223. The proposed hybrid funding mechanism is therefore unlikely to incur significant costs above any other mechanism. Indeed, if the revenue driver is set high enough, it will encourage distributors to seek out synergies and other efficiencies to reduce connection charges and thereby increase the amount of DG connected.

224. We note that there are national studies to assess the impact of perceived constraints on the connection of DG, not least:

- the renewables advisory board/carbon trust study, focused upon the developers' view point; and
- work being sponsored under DGCG (notably by TSG WS 5) to assess the scope of existing constraints and the degree to which these might be eased by better network management.

225. We imagine that these will inform the regulatory impact assessment (RIA) far better than the viewpoint of a single distributor: in the end, the developers' economic assessments are most important here.

226. Similarly, we note that the TSG has commissioned studies to consider the impact of DG on quality of supply and upon losses.

227. We contend that the IFI will yield significant positive returns for all customers. We expect feasibility studies to provide a 10:1 return. More research-biased projects are by definition less certain, but could be expected (if successful) to deliver even greater returns. Customers' exposure will be limited by the proposed cap; delivery of customer benefits will be assured by scrutiny of the programmes; and both will be reinforced by the requirement for distributors to contribute a significant part of the funding, as we would not invest even 20% of a project cost if there were no reasonable prospect of payback.

228. An unintended consequence of the current framework is that, because incentives for revenue efficiency are greater than for capital efficiency, there is little encouragement for companies to incur revenue spend on R&D to reduce capital spend. This is particularly acute when considering connections spend, which is largely funded on a pay as you go basis rather than over time. therefore, some enhancement of the current framework is required to stimulate further savings in capital investment on network development. Allowing £1-2m pa to secure ongoing reductions in a capital investment programme currently standing at £200m pa, and likely to increase significantly if DG takes hold, has to be a worthwhile investment by customers for customers.

229. Similarly, the RPZ will clearly yield benefits for all customers. Customers' exposure will be limited by the revenue cap; delivery of customer benefit will be assured through examining each scheme; and both will be reinforced by the requirement that the distributor underwrite the investment. To us, the RPZ concept is worth pursuing only if it offers unit cost reductions in excess of 20% (which would be applied more widely once the concept was proven).

230. Neither initiative would yield lasting benefits for DNOs, as regulation rightly acts to return all gains made by companies back to customers over time. The key is to provide sufficient short-term incentive for the firms that long-term improvements are secured for users.

231. We do not see any impact (positive or negative) on the energy mix arising from any of these proposals. Properly, they are constructed to assist all generators seeking to connect on the system. They do not affect competition and therefore will not of themselves bring forward generation from renewable sources in preference to that from elsewhere.

232. The combined impact of these initiatives on unit costs is clearly positive, although the precise value will vary by project mix. Generally, current solutions focus on constraining DG to minimise reverse power flow issues, and enhancing voltage control techniques. These provide developers with a range of price/performance balances: in the extreme, they can eliminate the costs of reinforcement (in its broadest sense). Conversely, there are no immediate solutions to fault level issues that do not impact adversely on service to other customers.

233. Overall, we expect unit costs to fall between 10 and 20%. Total system costs could reduce by a similar amount over time, probably after 2010, as persistent generation becomes more widespread and can offset demand growth.

234. In considering the impact of these proposals on total system costs, it may also be worthwhile separating out the benefits of generation from renewables and good-quality CHP against that from generation situated local to demand. From a pure distribution perspective, only the latter yields economic benefits through reducing the need for reinforcement: the former may well increase total system costs.

235. In this context, it is also important to consider the incentive properties of the proposed hybrid DG funding mechanism. If the revenue driver is set appropriately, it will encourage DNOs more actively to seek out synergies: while this will not directly impact total system costs (in the short term, it will bring forward investment), it could significantly reduce the element chargeable to DG.

236. We do not believe that this mechanism will bring forward significant speculative investment. Even if it did, the capacity made available could likely be used for demand customers, either generally in greater headroom or to improve quality of supply by reducing circuit lengths and increasing interconnection.

4. ASSESSING COSTS (Chapter 6)

237. We welcome Ofgem's statement that the best performer is not necessarily the company with the lowest cost.

238. 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.

4.1 Cost normalisation/publication of DNO information

239. We agree that there is a need for a robust assessment of costs and would support a transparent process and publication of relevant information. However we would reiterate the need to continue to consult with DNOs to gain agreement on methodology, definitions and relevant data ahead of publication, and that certain caveats are made on publication of data (eg subject to audit or regulatory accounting changes).

240. We agree on the need to normalise costs and the categorisation of controllable operating costs, fault costs, and non load related capex. We believe that it would be difficult meaningfully to breakdown costs below controllable cost level.

241. We recognise that there is further work on agreement of the normalisation issues and welcome Ofgem's commitment to work with DNOs on this issue.

242. As well as the issues raised in the consultation document in paragraph 6.9 we would add the following:

- differing accounting treatments, and application of overheads;
- differing legal and organisation structures, together with the outsourcing of services;
- definition of atypical cost to be agreed and consistency in treatment of weather related incidents;
- consistency on approach to insurance costs;
- transfer of non operational assets to third parties (e.g. impact on depreciation and controllable costs);
- treatment of ex gratia/GS payments and bad debts as atypical;
- treatment of internal margins; and

- specific DNO only issues such as maintenance work profiles.

4.2 Bottom up modelling

243. Any output from the bottom up modelling will only be as good as the accuracy and quality of data used to populate the model and already there are indications that the data used in populating information on fault costs, repairs and maintenance is not consistent across DNOs.

244. Some of the potential weaknesses and data issues are :-

- differing accounting treatments, allocations, attributions will mean differing definitions of costs between DNOs;
- treatment of overheads costs will distort unit costs;
- outsourcing of service provision would also distort costs;
- the creation of a virtual DNO by picking the lowest cost for each item without considering whether the resultant hypothetical company could exist in reality; and
- outliers may distort trends.

245. We assume that these models will act as a sense check of companies' own forecasts rather than the prime determinant of allowed income. In this context, such modelling could be used to identify significant issues for detailed discussion with companies.

246. Such an approach on capital expenditure would be useful and we would support the calculation of unit cost per unit of extra load and the specified unit cost for types of networks on non load-related capital expenditure.

247. However we would reiterate the limitation of this work as unit cost will vary - again based on the robustness of the data. In particular for non load-related capital expenditure, the business driver for the different categories (new business, replacement, and greenfield replacement) will have a significant impact on unit costs which would not be captured within the model.

248. Our conclusion is that bottom up modelling can only act as a guide in the process and it is critical to ensure that any outputs of this modelling are matched with other evidence and indicators used in the review process to determine the overall final proposals.

4.3 Top down modelling

4.3.1 General principles

249. We have set out our position on the use of comparative efficiency assessments in previous consultation responses, particularly our detailed comments on the Cambridge Economics Policy Associates (CEPA) report, *Background to work on assessing efficiency for the 2005 distribution price control review (September 2003)*.

250. Clearly, benchmarking can play a part in assessing efficiency for the 2005 distribution price control review. However, in any efficiency modelling that is undertaken the quality and consistency of information is the major issue. If the input data is not accurate, normalised and on a consistent basis then the outcome of any modelling is severely undermined. Given that data quality is the primary constraint, the type of modelling technique utilised may be a second order issue.

251. To ensure that any benchmarking is carried out appropriately, adjustments to raw data must be made for:

- differences in the reporting of costs;
- differences in operating conditions faced by each DNO;
- differences in measurable quality outputs delivered by each DNO; and
- differences in the risk borne by each DNO as a result of choices made about cost reductions.

252. It is only after all these adjustments that confidence can be obtained that a fair and responsible comparison is being made. Obviously, the more robust, transparent and complete the normalisation of the data prior to benchmarking, the more useful will be the results.

253. A note of caution with any benchmarking process is that if the variables used are not correctly specified then all that will be revealed is where companies appear to be placed with respect to these variables. This does not identify an efficient frontier.

254. In previous submissions we have set out at length the reasons why regression and data envelopment analysis (DEA) approaches are likely to identify a ‘frontier’ whose cost levels are unsustainable.

4.3.2 Cost categories

255. We welcome Ofgem's intention to consider a number of cost scenarios, as the dependent variable is key in cost assessment. We believe, that in a capital-intensive industry, the assessment of total cost, which includes both operating costs (opex), current capital expenditures (capex) and sunk capital costs, provides a more accurate picture of efficiency based on long-term optimising strategies employed by DNOs. For instance, DNOs that are increasing their capital spending to replace their existing capital stock can thereby limit their opex, appearing more efficient when opex alone is the focus of benchmarking. On the other hand, those that undertake more operating and maintenance activities and thereby postpone the replacement of ageing plant can appear to be poor performers. Therefore, it is important to consider opex and capex substitutions when evaluating each DNO's cost performance.

4.3.3 Benchmarking techniques

256. The use of a single benchmarking methodology is dangerous, and is very likely to lead to erroneous outcomes. Therefore, a method of validating the results from different approaches needs to be developed. This could cover a range of options from comparison to alternative methodologies to some form of expert judgement. Clearly, although benchmarking is an important tool a single methodology should not be used in isolation. Given this situation we welcome the fact that Ofgem is to consider a number approaches. However, we must reiterate that the modelling technique utilised may be a second order issue compared to having a valid data set that is normalised so that everything is on a like-for-like basis.

4.3.4 Frontier or average benchmark

257. We believe that price control reviews should be grounded in a thorough understanding of each licensee's business. Benchmarking approaches are deceptively attractive because they offer the prospect of an assessment of efficient cost levels that cuts out the need to understand where and why a company may appear to have higher costs than the level implied by the hypothetical standard.

258. If benchmarking is to be used to inform the review, prices should not be set on the basis of frontier costs which are likely to capture the short-run non-sustainable costs of a particular DNO in the chosen year.

259. The use of average costs in benchmarking is less risky than the use of frontier companies to inform judgements about efficient levels of costs. Given the asymmetry of risks and the value placed by customers on a secure electricity supply it is important to err on the side of caution. Nevertheless, it must be appreciated that even average cost approaches are not without risk and do not equate to the competitive market standard. Care must be taken to ensure that the data is truly comparable and the model specified as accurately and completely as possible.

260. Using a competitive market standard in benchmarking is informative. This standard indicates that in competitive markets firms operate at some distance (10-20 per cent) away from the frontier. This supports our position of advocating the use of average costs in determining the benchmark for setting prices. Clearly, it is safer than using frontier costs as it eliminates the risk of erroneous or rogue data influencing the outcome, even after the implementation of any normalisation.

261. Equally, using a frontier assessment to determine costs is analogous to a regulatory body exercising monopsonist powers. The exercise of monopsony power is generally not regarded as desirable in advanced industrial societies.

4.3.5 Total cost analysis

262. The use of total costs in benchmarking is preferable to using operating costs in isolation because it captures trade-offs between operating and capital cost solutions and because it corrects for differences in classification of costs that have not been discerned by the regulator. However the total costs assessment should be used to assist in forming a judgement about efficiency rather than to adjust the RAV.

4.3.6 International and panel data

263. Given the problems that we have identified in normalising information for the UK market, then any rationale for including international information is not valid. In the timescales available it is unrealistic to think that the cost base and input information could be compared on a like for like basis.

264. As with any other data, and perhaps in an even more exaggerated sense, utilising panel (multi-year) data needs to be handled with extreme care to ensure that we have a consistent baseline for the data.

265. Given the small size and limited variation in a one year British sample it is difficult to develop benchmarking methods that are at once adequately attentive to the special operating conditions facing the various companies and also permit credible hypothesis testing. Adding additional years of British data to create a panel (multi-year) data set is a possible means of solving these problems.

4.3.7 Inclusion of quality of supply in the analysis

266. Quality measures should not be excluded from the assessment. However, determining how to include quality is a challenge. Clearly, for an individual company higher quality implies higher costs. However, across all firms higher cost need not be correlated with higher quality.

267. The reason for this is that at a socially efficient outcome each company would provide that level of quality that equated the marginal costs of quality with the benefits in terms of customer willingness to pay for quality at the margin. It would therefore be efficient for society if firms with high costs of provision of quality, say those with long lines, had lower quality of supply. Across the sample as a whole this will tend to confound any simple relationship between quality and cost – even though the level of quality for each firm may be an important cost driver. A null result from even a well specified regression including quality would not therefore imply that quality was unimportant as a cost driver.

4.4 Mergers

268. Ofgem intends to benchmark merged groups as well as individual DNOs and we agree that this should be one of the comparisons made.

269. With respect to its policy on the treatment of mergers, the consultation states that there are two ways Ofgem can approach the issue of revenue reductions:

- **continue to reduce revenues by £12.5m p.a. (in 1997/98 prices) for each merger** – this is the policy applied in DPCR 3 (based on expected merger savings) and which Ofgem had generally said would apply to all mergers up to May 2002. Such revenue reductions would not be applied until the fifth anniversary of the merger; or
- **deduct £32m per merger over five years to offset the loss of a comparator** – this would treat all mergers on a consistent basis. This would generally result in

lower revenue reductions depending on how mergers already bearing revenue reductions in DPCR 3 were treated.

270. In the October consultation document Ofgem stated that it intends to apply the merger policy in force at the time that each merger took place in its assessment of allowed income at DPCR4. This should still be the case. We do not believe that it is necessary to move to the £32m policy (for the loss of a comparator) for mergers prior to May 2002.

271. No further adjustment is necessary to our costs because the normal regulatory review processes will capture the £12.5m 'guaranteed' by Ofgem; moving to a £32m penalty would introduce retrospection and introduce an additional penalty.

272. 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.

273. Although precedent may suggest that NEDL and YEDL will be treated consistently with other companies that had merged at that date, 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.

274. Ofgem has signalled that it expected 'an annual sustained savings of £12.5m' 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 £12.5m was the total amount Ofgem had 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. £12.5m] since the incentives to maximise efficiency will have been allowed to operate freely'. Ofgem held out the prospect that the £12.5m 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 £12.5m (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 £12.5m ‘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 £12.5m across the two companies. This view of Ofgem’s intent is consistent with the Ofgem statement on the TXU/EdF joint venture, 24Seven.

275. 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).

276. 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 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.

4.5 Total factor productivity

277. We are commenting in a separate submission on CEPA’s study *Productivity improvements in distribution network operators,* (Final report, November 2003). However, our views on the use that can be made of total factor productivity (TFP) analyses are summarised below.

278. Trends in TFP are unlikely to assist in determining efficient costs because the significant rate of TFP gains achieved during the period since privatisation are not an indication of the likely future trend.

279. CEPA considered both partial and total factor productivity measures and both the possibility of comparing firms at a specific date and also comparing performance over time.

280. In relation to partial productivity measures CEPA note that:

> ‘one cannot sum up the efficiency savings that these measures give for each function and suggest that the total efficiency saving is achievable for the company as a whole. This is to neglect the fact that companies may choose to substitute one type of expenditure for another hence

> giving them best performance on some measures but not on others leaving best performance on all measures simultaneously unachievable.' (p 25).

281. This point is general and applies to any technique applied to a sub-set of total costs, or potentially to total costs not allowing for quality differences.

282. In relation to TFP CEPA noted that:

> 'As a long term objective tying X to the TFP growth rate in the distribution sector might be a desirable goal.' (p 27); but that

> 'the UK has posted another impressive improvement in efficiency of its electricity distribution sector with high dispersion of productivity growth rates around a high average. This implies that it may be too early to consider TFP in calculating the X factor.' (p 29).

283. We can see the attraction of using TFP rates to assist in price control reviews. However, a robust TFP based assessment requires that the input data is sound and account has to be taken of the fact that the retail price index element of RPI-X regulation already captures economy-wide productivity improvements. The X factor should reflect only those improvements that may be expected above those achieved in the economy as a whole. However, as we approach the fourth price control review since privatisation it is appropriate to ask why it is considered necessary to try to estimate the achievements that may be made in the future by DNOs. There is a general consensus that those efficiency gains that were easiest to achieve have now been secured. CEPA's Dr Pollit indicated at the Ofgem workshop that there were two reasons why regulators might try to anticipate efficiency gains at a price control review. The first was to ensure that the future of incentive regulation was politically sustainable: capturing only the known gains from the prior period left a potential political problem if incentive regulation was perceived by the public to give companies too easy a challenge. The second reason advanced by Dr Pollit was that there was evidence that setting companies harsher Po/X factors correlated with greater subsequent cost reduction.

284. With respect to the first observation, we believe that there is little prospect of significant, let alone excessive, out-performance after three price control reviews and after we have already reduced operating costs by 60 per cent since privatisation.

285. With respect to the second observation the only reason why it might be justifiable to set tougher Po/X factors to encourage greater efficiency would be if the capital markets were incapable of driving out efficiencies. The level of the Po/X factor does not affect its incentive properties. Of course, setting Po/X factors for all companies by reference to the cost of 'frontier' companies may force companies to adopt a different and higher risk profile. It would, however, be a mistake to direct regulatory policy towards that end without full consideration of whether customers desire such an outcome.

286. We are therefore not convinced of the need to anticipate gains at a price control review.

5. FINANCIAL ISSUES (Chapter 7)

5.1 The financial ring-fence

287. We believe that there is no need to strengthen the financial ring-fence provisions that are included in companies' licenses.

288. 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 does the inability to securitise assets and the need to inform Ofgem ahead of any dividend payments.

289. The 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 and would, therefore, suggest a more explicit mechanism is not appropriate.

5.2 The cost of capital

290. We welcome Ofgem's recognition that a move to a post-tax calculation is desirable. We do, however, seek clarification of the definition of 'post-tax'. Does this mean post-tax debt, post-tax equity cost of capital, which Ofwat quotes for its cost of capital, or the pre-tax debt, post-tax equity cost of capital, which Ofwat uses in its financial model to avoid double-counting the tax benefits of debt?

291. Ofgem is aware that an update of the Oxera paper is in preparation and will be made available to Ofgem in due course. Ofgem is also aware that NERA has conducted work for both the water industry and EDF. The work for the water industry is due to be updated shortly. The work indicates that the capital asset pricing model (CAPM) should not be biased by short term market conditions on specific components such as beta and debt premia. This work also draws on international benchmarks and suggests cross checks to other methods should be utilised to ensure the CAPM does not under estimate the required rate for items such as issuing costs. We would support such an approach.

292. Subject to the recognition of the companies' tax position and also efficiently incurred embedded debt we support the continuance of an industry wide cost of capital.

5.2.1 Gearing

293. The use of an assumed level of gearing has a number of advantages. First, and perhaps most significantly, it has the merit of simplicity and transparency, as one cost of capital figure is assumed for the whole sector. This also, arguably, limits regulatory intrusiveness into the precise capital structure of firms and possible debates that might develop on issues such as the appropriate treatment for junior debt or preference shares.

294. Second, using an assumed figure is likely to provide greater incentives for the companies to seek out and adopt different financial models. Under this view, the cost of capital figure set by Ofgem can be seen as a regulatory target that companies would seek to outperform, in exactly the same way as opex or capex efficiency targets. If a company knew that its cost of capital figure would reflect its financial structure, there would be little incentive to adopt such a policy.

295. In setting an assumed level of gearing recognition needs to be given that there is only weak evidence of 'efficient' level of gearing. We believe Ofgem should maintain the assumed level of gearing at 50% despite evidence that investment grades can be maintained with higher gearing for the following reasons:

- to assume a higher level will incentivise companies to push gearing levels even further;

- the sector as a whole is facing an increase in capital requirements which it needs to finance, the incentive to increase gearing will mean the finance requirement is likely to be met from gearing up so pushing the industry average even higher;
- higher levels of gearing result in less financial flexibility to respond to unforeseen circumstances and weakens incentives for innovation; and
- care also needs to be taken to avoid systemic failure within the sector.

5.2.2 Embedded debt

296. We submitted a paper on embedded debt in November 2003 and maintain that the debt incurred by NEDL and YEDL was efficiently incurred and should be allowed in the cost of capital. In setting the allowed income to be earned by a DNO in the next regulatory period Ofgem are seeking to ensure that customers only pay for the costs that would be incurred by an efficient DNO.

297. A copy of the paper is attached and the conclusions from the paper are reproduced here :-

> *The principles of incentive regulation should ensure that the rate of return allowed is sufficient to continue to attract capital to finance future investments. This principle requires Ofgem to allow existing providers of finance adequate returns to recover the cost of past investments.*
>
> *If Ofgem's forward-looking estimate of the cost of debt does not take account of the embedded cost of debt, then it is implicitly assuming that all the historic debt can be refinanced at existing spot rates without payment of financial penalties. Clearly this is unrealistic and is equivalent to disallowing other sunk costs, with the same implications for regulatory risk and incentives.*
>
> *The regulatory process has to ensure that all of the components of the allowed income of the DNO are incurred efficiently. Within an incentive regulatory system there can be no 'blank cheque' for any element. Regulation cannot provide a guarantee to cover the costs of a DNO's actual debt portfolio. But financing which satisfies objective prudency tests should be allowed over the length of the financing period.*
>
> *DNOs want to make efficient long term financing decisions. In order to do this the existing debt costs must be remunerated in full. The only exception being if Ofgem can demonstrate that these costs arose as the result of particular kinds of financial mismanagement or inefficiency that need to be discouraged in the future.*
>
> *We would therefore support an adjustment to the allowed cost of capital for NEDL and YEDL in respect of embedded debt costs. Such allowance to be subject to Ofgem applying objective tests of prudency.*

We look to working with Ofgem on the resolution of this issue.'

5.3 Financial modelling and indicators

5.3.1 Financial modelling

298. We provided comments on 13 October 2003 following our initial review of the model but have not, as yet, received a response to the comments made. We did however, attend a workshop on 28 January 2004, to discuss the issues previously raised by DNOs, which was a useful step towards developing the process to deliver the final model in April 2004.

299. We look forward to receiving a further version of the model incorporating the revisions agreed at the workshop along with Ofgem's further thoughts on issues raised by DNOs. We welcome further discussions and workshops on the development of the model.

5.3.2 Financial indicators

300. We look forward to the detailed work with Ofgem on reviewing and using the financial model.

301. Although the calculation of allowed income using the 'normal cash flow model' is in real terms the importance of the financial indicators requires that they must be expressed in outturn prices.

302. Whilst the modelling can take account of the hypothetical capital structure assumed by Ofgem it must recognise:

- cash interest paid on existing external debt at the actual interest rate being incurred;
- tax payments based on the actual levels of capital allowances pools and future allowed capital expenditure;
- future changes to tax allowances which are known and quantifiable at the time of the review; and
- future changes to the timing of tax payments that are known at the time of the review.

303. It is appropriate that the tax payments included in the financial modelling should relate to the DNO as a standalone entity and therefore group relief claimed by other members of the overall group should be ignored.

304. In looking at the results of the financial modelling as a check on the calculation of allowed income it has to be recognised that any changes made to the outcome of the 'normal cash flow model' should be on the basis of the long term viability and not merely a short term fix to solve an immediate cash flow problem. Masking flaws in the 'normal' calculations with cash flow dragged from the future may look as though it solves the problem but it will rebound against future customers and may impact external perception of the overall viability of the DNOs and increase the view of regulatory risk.

305. Investment grade covers a wide range from the highs of AAA+/Aaa1 down to the limit of BBB-/Baa3. In looking to be 'comfortably' in this range we feel it is appropriate to target the single 'A' category. This allows some degree of comfort from external factors which may result in market, or agency, perception being negatively impacted other than as a result of DNO action.

306. Whilst we agree that accounting based ratios are useful we also agree that measures on a cash basis are more appropriate and are gaining increasing importance in the minds of any external reviewers of historical and prospective financial performance.

307. In general terms we agree with the ratios set out in 7.62 of the consultation paper. The term 'maintenance capex' needs to be defined and the definitions of the ratios should ensure that:

- debt and interest refer to net amounts and not gross amounts. This will allow for recognition of the effects of any unused cash balances retained within the DNO. Whilst such balances will be invested through the group treasury function the DNO retains the economic benefit of the cash and this should be reflected in the ratios;
- debt and interest amounts should reflect both external and inter-company borrowings and investments; and
- the modelling reflects the actual cash payments for interest and not the hypothetical interest amounts assumed by Ofgem.

308. In setting a cost of capital the assumption is that the interest payments have to be made each year in order to satisfy the needs of the debt providers. By the same process the cash generated by the DNO should allow the equity providers to receive a dividend equivalent to the nominal return assumed within the cost of capital.

309. In those circumstances where the level of capital expenditure is such that the RAV value is increasing then the level of dividend each year could be limited, or further equity injections may be required. In order to maintain an appropriate level of debt relative to RAV.

310. Where the RAV value is stable then the level of dividends each year should be equivalent to at least the nominal return assumed within the cost of capital. The cash flow modelling undertaken to calculate allowed income only looks at cash flows in net present value terms. As such a stream of annual cash flows (dividends) may give the same net present value result as a single cash flow as the end of the review period (closing RAV). However, restricting annual dividends, even where these are rolled into the closing RAV, must heighten the level of uncertainty and would therefore increase the regulatory risk and hence the allowed cost of capital.

5.4 Pensions

311. Overall the proposals set out by Ofgem follow the discussions we have held and the methodology we set out. The following paragraphs give some additional comments on the detail set out in the consultation paper. The following are the major areas which still need to be included:

- the proposed exclusion of early retirement deficiency costs (ERDCs) from the calculation of surplus and deficits within the scheme fail to reflect the reality of the historical position;
- pensions costs should reflect all contributions and not just those made to Electricity Supply Pension Scheme (ESPS);
- recognition has to be made of the asymmetry inherent within the scheme that means the employer, and hence the DNO, is really liable to cover the full amount of any deficit whilst the members expect to receive an appropriate share of any surplus; and
- the methodology must allow for the normal workings of the scheme in the case of block transfers of members, such as in CE's 2001 transaction with Innogy, without reference to the historic position of the scheme from which the members are being transferred.

312. In previous price reviews the issue of pensions has not been subjected to any form of scrutiny and therefore there are no precedents which help the current position. We

therefore recognise that pragmatism is required in both setting the opening position and also in setting the rules that can bring transparency to the future treatment of these costs. However, whilst a pragmatic position needs to be found for the start point it is also considered that the opacity of history should not allow such a critical calculation to be flawed.

5.4.1 Methodology statement

313. We agree that the framework should determine an explicit pensions allowance for the forthcoming review. This allowance would cover both the required ongoing funding rate for current members as well as arrangements put in place to fund any deficits. We believe that Ofgem is proposing that the costs of the DNO which are then subject to benchmarking will exclude these agreed pensions costs. To do otherwise would be to fail to recognise the special circumstances that the ESPS rules bring to bear on DNO costs.

314. The timing of price reviews and scheme valuations are on separate cycles and therefore there will always be some uncertainty as to the actual pension contributions that a DNO will have to make over the forthcoming review period. Where the two cycles intersect, such as is the current case, this brings additional complications. The scheme valuation includes appropriate discussions with the scheme trustees, and their advisers, which includes, amongst other issues, their perception of the financial health of the overall business. This brings different concerns depending on whether or not the overall business is dominated by DNO(s). Where DNOs dominate then the uncertainty of the review outcome will be a factor which the trustees will take into account. In looking to the timing of deficit funding the actuary has to certify that any proposals put forward by the employer are 'reasonable' and therefore the financial health of that employer is a significant factor that the actuary has to take into account. Thus uncertainties in the regulatory process for the review may influence the actuary and result in deficits having to be funded over shorter periods than the 'normal service lives' envisaged by Ofgem.

315. We believe that pensions represent a category of cost that can be treated within the uncertainty mechanism proposed earlier in our response. It is not satisfactory to deal with under/over recovery of pension costs through adjustments at subsequent reviews for two reasons. The first is that the amounts are potentially large – giving rise to cash flow considerations. The second is that the review process is not sufficiently

mechanistic for it to be certain that recovery of the additional costs will not (perhaps unconsciously) encourage a regulator to adopt a tougher line with respect to judgements that are made on other cost items at that review.

316. Moreover, Ofgem's proposals for dealing with changes in funding requirements through adjustments at the next review period have a trigger point set at 'significant financial difficulties'. This is too severe a test; it would be more sensible to set it at a 'significant increase' in the level of pension costs allowed in the price review. We would suggest that an interim adjustment could be made where pension costs in the remaining years of the current price control period increase by more than 25% from those allowed.

317. We appreciate that the different company structures adopted by each DNO owner should not impact the allowances included for pensions within the price control. We therefore support the inclusion of all pension costs that relate to the distribution business and not just those related to the specific staff of the licensee itself. Of course this can only apply to those companies within the DNO owner's group and will exclude any pension costs related to services provided by fully out-sourced third parties.

318. In seeking an allowance for pension costs it is recognised that the appropriate costs related to the DNO have to be disaggregated from those of the overall scheme(s) which include DNO employees, and former employees, within their membership but which also comprise members whose activities do not, or did not, relate to the electricity distribution business. To do this will require a number of adjustments, the complexity of which will reflect the diversity and composition of the individual schemes.

319. In 7.73 Ofgem set out four adjustments, our comments on these are as follows:

- we note Ofgem's wish to avoid cross subsidies such that only the liabilities related to DNO activities, and former activities, should be included;
- we agree that adjustment should be made where actual contributions to the scheme are different from those allowed in previous price reviews. However, this does require that the allowances in previous reviews can be measured and the lack of previous transparency hinders this process. These issues are explored later in this paper;
- we continue to disagree that any adjustment needs to be made where ERDCs have been charged against previous levels of surplus. Again these issues are explored later in this paper; and

- we agree that the costs from failures in financial stewardship should be excluded but would welcome Ofgem indicating examples of circumstances that it considers fall into this category.

5.4.2 Allocation between price-controlled and non-price-controlled activities

320. Given the requirement to ensure separation of business activities it is appropriate that active members should be allocated according to their present employment. In accordance with the principle in 7.72 this would also apply to employees of affiliate companies acting as contractors.

321. For those employees who left prior to the implementation of formal business separation any allocation to price-controlled activities would have to be on the basis of salary allocations which may require the acceptance of a pragmatic solution.

322. For the pre-privatisation leavers the pragmatic solution proposed of looking at the 1990/91 allocation of overall salaries seems acceptable as a proxy for splitting the underlying work of an Area Board. An adjustment would have to be made for the relatively small number of staff who were not in ESPS at that time but a workable solution is achievable for individual companies.

323. Having derived a methodology to allocate the overall liability between the DNO and non-DNO elements the allocation of assets between the two elements is equally important in order to calculate the amount of the DNO related deficit or surplus.

324. Whilst allocating the assets in the same pro-rata proportions as the liabilities may seem the simpler solution it fails to reflect the investment strategy that mixes bonds and equities in proportions that reflect the maturity of the scheme's obligations, although it is recognised that schemes are unlikely to have matched all pensioner liabilities with bonds.

325. Allocation of assets on a set of matching criteria provides an appropriate method which will also provide flexibility for those larger funds where the proportion of DNO related staff is lower than in some other schemes such as for CE.

326. We agree with the Ofgem assertion in 7.78 that concentrating more equity assets towards the 'less mature' categories of member would provide a weighting of the current deficit to the active members, and hence by inference to the DNO business, but we do not agree that such an outcome would be disproportionate; rather it reflects the

reality of the investment strategy followed. Over the long term it is still likely that investments in equities will provide greater returns than through bonds and therefore equities will continue to be a valuable element of the pension scheme assets. As a result long term prices to customers will be lower reflecting the lower level of contributions needed from DNOs. In contrast, allocating a mixture of bonds and equities to active members can be expected to result in higher immediate pension contributions for active members because – in valuing their liabilities – the assumed pre-retirement investment return will be lower reflecting the lower anticipated returns from the proportion held in bonds.

5.4.3 Over or under provision

327. As mentioned earlier, the issue of pension costs has not been a significant element of previous price reviews. This is highlighted by the uncertainty within both Ofgem and the DNOs as to what pension costs were included or even allowed in the last review.

328. Ofgem set out three alternatives for trying to calculate the inherent allowance for previous reviews, potentially all the way back to privatisation. The last review was the most clearly delineated to date and therefore the fact that there are problems with the data for that review means that we do not see how it could be feasible to extend the application of hindsight to any period before 2000/01.

329. We also feel that even for the current review the methods suggested by Ofgem fail to provide the correct solution as they miss the fundamental point that the overall allowance for operating costs in the current review period was driven by three elements none of which related to the forecasts submitted by DNOs.

330. The first two elements were the 1997/98 actual costs of the DNO and the equivalent costs of the two frontier companies. The final element was the slope of the line assumed to get from 1997/98 levels to a point that was three quarters of the way to the frontier.

331. Subsequently the review of the Historic Business Plan Questionnaires (HBPQs) submitted in 2003 indicates that there are issues of comparability over these frontier costs which complicate any hindsight analysis.

332. A significant proportion of pension cost is attributable to capital costs. We are not aware of any allowance for pension costs built into capital allowances derived by

Ofgem from the PB Power DPCR3 modelling. It would be helpful if Ofgem could reveal the pension component of these allowances for each company.

333. Looking at Ofgem's three methods separately:

- using the base year relationship of pension costs (on an accounting basis) to salary costs assumes that accounting and cash costs are the same. It also assumes that the accounting data from each DNO is on a comparable basis. It is the cash costs that are to be measured so accounting data is unlikely to be a reliable measure. As indicated above this also fails to allow for the 'frontier' factor applied to the DNO 1997/98 costs in deriving the allowed costs in the normal cash flow model;
- however, if this method was amended to reflect the method used to calculate allowed costs in the current review it would form an acceptable basis which could be applied from 2000/01. Application into earlier periods is not acceptable;
- assuming that allowed costs are the same as actual costs incurred seems to be a strange solution, it is equivalent to assuming perfect foresight in setting the allowances; and
- the third solution is also equivalent to assuming perfect foresight but then compounds the problem by assuming that allowances were set based on an average level so individual DNOs will gain or lose against that average. This would also have the effect of giving benefits to those DNOs who had higher than average contributions which may have actually been the result of previous underfunding or other reasons which Ofgem may well have excluded in other circumstances.

334. Where adjustments are made to the actual contributions then there has to be an allowance for the returns that would have been earned had those revised contributions actually been paid into the scheme. Ofgem assume that the returns used would be based on a benchmark such as published by the WM Company. However, Ofgem have also indicated that they do not want to second guess the investment strategy of the scheme in overall terms so we do not see why it is inappropriate to use the actual returns earned by the scheme on investments rather than any generic set of returns.

335. In 7.84 Ofgem set out the rolling forward of adjustments. However, we feel that the statement has confused where additions and deductions should be made. Given that the contribution rates are set by the actuarial valuation then if the customers have not paid for all of those contributions the actuarial valuation as attributed to the distribution business is overstated and the excess contributions should be deducted and not added

as indicated by Ofgem. It would be useful to see an example of how Ofgem feels such a situation may have arisen.

5.4.4 Early retirement deficiency costs

336. We continue to argue that the use of pension surplus for restructuring is appropriate and as such there should not be any adjustment made to assets to back out such charges. DNOs inherited staff at privatisation and the rules of the scheme require ERDCs to be incurred when these staff leave as a result of any restructuring.

337. As indicated in the 'Summary of responses' document it was a well known fact that ERDCs were being charged against pension surpluses and it was a well documented facet of every scheme valuation and the agreed uses of surpluses.

338. We would also observe that the DNOs' schemes were in surplus at the time of the last review. Inland Revenue rules require that something is done to prevent the continuing build up of surpluses. In these circumstances the appropriate question is whether it was inappropriate or reckless for some part of the surplus to be used to fund the ERDCs. The important point is that something had to be done; using surpluses to fund ERDCs was legitimate. It was not reckless (indeed the trustees, the independent trustee and the actuary all had to be satisfied with the use of surplus). Reducing costs in the business is generally something that is to the benefit of customers. It is hard to see why this particular use of the surplus in something that should be clawed back because events in the financial markets turned out differently.

5.4.5 Stewardship

339. Whilst we would be surprised if any material breaches of stewardship would be discovered we agree that returns should be adjusted to reflect what should have been earned. However, care will have to be taken to ensure that hindsight is not applied to behaviour that was legitimate in the circumstances that prevailed at the time that the trustees and their advisers made their decisions.

5.5 RAV roll forward

340. At DPCR3 some companies either failed to treat all fault costs incurred in the period up to 1997/98 as opex or they failed to provide Ofgem with the full information to enable Ofgem to make adjustments to achieve its intention to treat these costs as opex.

Therefore some such costs were recorded as capital and entered the RAV for these companies.

341. We understand that these companies also included some fault costs in their forecasts of capital expenditure for the period 2000-2005. These companies contend that irrespective of whether it was Ofgem's intent to treat these costs as capex (and therefore falling within the RAV) they were so treated at DPCR3 and, therefore, this treatment must be honoured at DPCR4.

342. We do not wish to enter the debate about the proper treatment of these companies with respect to the calculation of the opening RAV for the DPCR4 period. However, we are deeply concerned that we should not be disadvantaged relative to companies whose disclosure was not as complete as was our own and we also wish to ensure that any failure by others to disclose information to Ofgem (for whatever reason) at DPCR3 should not leave either NEDL or YEDL in a relatively worse position.

343. The fact is that both NEDL and YEDL provided Ofgem with the information it needed to treat these costs as opex. As a consequence of the application of the efficient frontier regression methodology NEDL's and YEDL's allowed opex costs were largely determined by the reported opex of Eastern Electricity. As a result NEDL and YEDL were deprived of that proportion of opex that Eastern Electricity was treating as capital. This was clearly accidental.

344. If these companies are allowed to carry forward the consequences of this treatment into DPCR4 it requires that something equivalent is done at DPCR4 to ensure that all companies are treated equitably. Failure to make an equivalent adjustment would preserve the unequal treatment into the future.

345. However, we also appreciate that customers should not be expected to pay the same set of costs twice - once in opex and once in capex. Our proposal therefore is that for the period ending 31 March 2005 Ofgem should restore to the RAVs of the companies who behaved in accordance with Ofgem's intentions that element of fault cost expenditure that they were deprived of by the efficient frontier methodology where the frontier was set by a company whose operating costs did not include all of its fault costs.

APPENDIX 1: IIP Targets

(The following is an extract from our response to the October Update)

We appreciate the interactive nature of the work done so far to date to try to understand the difference between companies' quality of supply performance. However, we have concerns regarding the application of the results in the setting of the performance benchmarks.

The key concerns are:

- the benchmarks are based on only one year's performance;
- they do not fully take into account known differences in network makeup;
- they have taken insufficient recognisance of weather variability; and
- the starting points are currently not realistic.

Benchmarks generally based on one year's performance - Data previously provided on the number of HV weather-related faults and an examination of the overall figures clearly indicate that 2002/3 was an atypical year with low CI and CML due to the very benign weather conditions. Companies have to aim for delivering the targets in at least a normal weather year and can not trust to luck in having benign weather. A simple solution to this issue is to use the disaggregation process to determine the distance from benchmark performance and then apply this distance to a realistic starting point to derive the target figures.

Benchmarks do fully take into account known differences in network makeup - HV has been the main area of focus for disaggregation as it makes up by far the largest part of performance and shows the greatest variability due to inherent and inherited factors. The work done by the DNO working group has defined the basic groupings for dividing up performance into circuits with similar physical characteristics. However, even within the HV groupings there was one major factor that was known to give rise to markedly different performance and this was whether the circuit was unit protected or standard radial. Data has been gathered on this (circuit types) and reported to Ofgem but it has not been used in calculating any of the benchmarks.

Unit protection is now used only when extremely high reliability is required, usually for industrial customers, and normally forms a small part of most DNOs' HV networks (<5 per cent - even less in terms of customer numbers). It is little used because of the very high costs involved in both switchgear and communication circuits. However, certain DNOs have extensive parts of their network with this type of protection because of historical factors. These are Manweb with 45 per cent of HV circuits of this type and LPN with 20 per cent (Circuit types 7, 8, 9 and 11). The effects of this show through clearly in the disaggregated data with many circuits for these two companies having faults but no customers affected.

Ignoring the above factor has led to some perverse results in the targets given for the FBPQ process with both LPN and especially Manweb having 2010 targets very much worse than their present performance. It has also meant that other DNOs have been given much tighter targets than it is realistic to achieve, with the type of circuits causing the distortions being too expensive to replicate.

It would be fairly simple to correct the process for these distortions. Virtually all of these type of circuits are underground so a simple pro-rate adjustment to the benchmarks in the underground categories for the volume of these circuits was all that is probably needed.

Benchmarks have taken insufficient recognisance of weather variability - Information previously provided on the number of weather related faults has indicated that 2002/3 was an atypical year because of the very benign weather conditions. The proposed targets for 2020 are purely based on this one year.

Equally, as there were many less faults in this year than normal, it is to be expected that restoration times are shorter than normal. The issue is that a low number of faults in a company that is geared up to deal with more inevitably results in a shorter restoration time than that which could be sustained in a more normal year. A further factor is that severe weather usually results in multiple faults in the same period that inevitably take longer to restore than the isolated faults that occur at other times. This has particular relevance to the use of ‘upper quartile’ restoration performance in setting the CML benchmark. Three companies, Hydro, WPD South West and WPD South Wales have effectively set the ‘upper quartile’ restoration performance and an examination of their performance shows that using this leads to an unsustainable result. Between 2001/2 and 2002/3 Hydro Electric improved CML by 44 per cent, WPD South West by 30 per cent and WPD South Wales by 32 per cent. It is no coincidence that these three companies have the highest proportion of overhead circuits compared with underground in the country and hence are likely to improve most in benign weather. Given this situation, the group average restoration performance in 2002/3 may be more representative of the upper quartile performance that could be expected in a more normal year.

The starting points for the benchmarks are not currently realistic - The EHV benchmarks are based on the company's own 10-year average, yet the target calculations are based on a starting point of the 2001/2 and 2002/3 average. If we use the 10-year average to even out the variability, then the starting point for the target setting should use the same value.

At LV the benchmark is based on actual 2002/3 performance and yet the start point is again the 2001/2 and 2002/3 average. Fortunately LV performance (excluding storms) is relatively stable so this mismatch does not have a significant effect.

HV has exactly the same problem. All benchmarks are based on 2002/3 only and yet the starting point for deriving targets is the average of 2001/2 and 2002/3. A simple examination of the differences between 2001/2 and 2002/3 performance shows that overall there was an improvement of over 10 per cent in CI and 15 per cent in CML between the two years.

Information previously provided on the number of weather related HV faults indicated that 2001/2 was a more typical year for weather related incidents. For most DNOs this would therefore be a more realistic starting point for determining targets. This means that the CI targets for 2010 have at least half the above difference, i.e. 5 per cent improvement, built into them before even looking at relative performances, gap closures and the 0.5 per cent per annum assumed improvement in the benchmark. For CML the position is worse, with the starting mismatch being 7.5 per cent.

We would therefore suggest that the starting points for the calculation of targets should be:

- EHV - the 10 year average performance
- LV and EHV - the worse of 2001/2 and 2002/3 performance

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 in isolation 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).

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 or it may have had an easier cost/benefit profile within which to optimise its output. Frontier performance can only be defined on a relative basis taking into account all these factors. 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.