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Dear Nienke,

Electricity Distribution Price Control Review – Policy Document

You have invited views on the above document published in March and I am pleased to attach our comments.

I hope that you find our comments helpful. We would be pleased to discuss any of the views expressed. In the meantime, we look forward to continuing to play an active and constructive part in the ongoing work on the price control review.

Yours sincerely

Rob McDonald
Director of Regulation

CHAPTER 3 FORM STRUCTURE AND SCOPE OF THE PRICE CONTROLS

Revenue drivers

We support retention of the 50/50 weighting between units distributed and customer numbers for the reasons set out in the paper. We also agree that it would be appropriate to use the actual customer numbers reported each year under IIP in the price control formula, rather than an ex ante forecast. The use of actual customer numbers would reduce DNOs (and indeed Ofgem's) exposure to forecast risk.

We are however concerned about the proposed review of the basket weightings within the formula. The present set of weights have been in use since privatisation and, in our view, provide adequate protection to both customers and DNOs that changes in the mix of units distributed feed through in an appropriate manner to a change in allowed revenue. We are also concerned that this major piece of work is being started late in the price control process. The weights are an important revenue driver and any change could have a profound effect on allowed revenues (positive or negative). Accordingly, we would urge Ofgem to retain the present weights in the interest of regulatory stability.

Price index

We would be firmly opposed to a change in the price index from the current RPI calculation used in the formula for the following reasons:

- RPI-X has been a central part of the price control framework since privatisation. The adoption of an alternative index for future price control periods would raise significant issues about regulatory risk going forward. In particular, the RAV is currently inflated using the RPI and current valuations of network businesses have been calculated on that basis. A change in index would have uncertain effect (plus or minus) and this would increase perceptions of regulatory risk;

- We do not believe that there is any evidence that the CPI is a better measure of the inflationary cost pressures facing DNOs than RPI. The CPI uses some prices excluded from RPI, particularly educational and financial services. It is not clear how these could be expected to produce a more accurate indicator of DNO costs than RPI;

- Indeed, the CPI measure is relatively new and this exacerbates the risk to DNOs (and Ofgem) that it would produce significantly different outcomes; and

- More generally, if Ofgem are determined to seek out the index most likely to be cost-reflective, there may be more merit in adopting a measure based on wage inflation (which tends to be above both RPI and CPI), since labour costs are a significant proportion of DNOs costs.

Transmission exit charges

We support the decision to retain the current pass-through of exit charges for the reasons given in the paper and because these charges are in any event determined by Ofgem on an annual basis in approving NGC's tariffs.

Treatment of wheeled units

We continue to believe that wheeled units should remain an excluded service. We understand Ofgem's point about the incentives on DNOs if the outgoing charge is an excluded service and the incoming charge is subject to full pass-through. However, we believe that this problem is overstated. In particular, the DNO that is subject to the wheeled units charge does still have an incentive to minimise that charge because if it does not, it faces a risk that its inefficiency may not be allowed by Ofgem in future price control periods. In addition, the inclusion of wheeled units as part of the main price control set in advance for five years does not address the circumstances of an additional wheeled unit liability (or charge) arising mid-price control. There is also no evidence to suggest that present wheeled unit charges are unreasonable.

For these reasons, we believe that the current treatment of wheeled units as an excluded charge should continue, but we do agree that there should be an ex-ante allowance for the current price control period for those DNOs that currently pay such charges. Under this framework the fact that the DNO paying the charge would not receive any funding for new wheeled units charges mid-price control would provide an additional incentive for them to keep those charges to a minimum.

If Ofgem nonetheless persist in including wheeled units in the main price control, then the precise mechanism for achieving that will require further thought. We believe that the simplest and most equitable way of including such costs in the price control would be to exclude them from the subtraction of excluded services under the "building blocks" calculation. That is, Ofgem tend to calculate allowed revenue based on opex, plus depreciation, plus return on RAV (including capex and depreciation), minus excluded services. The issue of wheeled units could be addressed by taking the DNO forecast of wheeled unit revenues (subject to any adjustments deemed appropriate by Ofgem) and removing it from the total of excluded income to be subtracted from allowed revenue. A corresponding addition to allowed revenues would be required for those DNOs that would incur a wheeled unit charge.

EHV Charges

We continue to believe that EHV charges should remain an excluded service. The volatility associated with the number of EHV units distributed from year to year continues to be a good reason to exclude EHV revenues from the standard price controlled revenue formulae.

If Ofgem nonetheless persist in including EHV charges in the main price control, then the precise mechanism for achieving that will require further thought. As above we believe that the simplest and most equitable way of including such costs in the price control would be to exclude them from the subtraction of excluded services under the "building blocks" calculation. That is, the treatment of EHV charges could be addressed by taking the DNO forecast of EHV revenue (subject to any adjustments deemed appropriate by Ofgem) and removing it from the total of excluded income to be subtracted from allowed revenue.

The other protection that is required, in our view, is to isolate DNOs' EHV revenue requirement from the tariff basket mechanism for indexing allowable revenue from year to year. As Ofgem notes, DNOs tend to charge EHV customers on a site-specific basis. Only a small component of the charge, if any, is linked to the actual units consumed by the EHV customers. It is therefore not appropriate to link the indexation of either the EHV revenue or the overall allowable revenue to the change in EHV units from year to year.

Our proposal for the treatment of EHV revenue in the price control formulae is to keep the EHV allowable revenue separate from the quantity of allowable revenue which is indexed from year to year through a combination of unit basket weights and change in customer numbers. The EHV sum could simply be subject to the overall RPI-X indexation. The benefits of this approach are:

- DNOs would be protected from untoward variation in price-controlled revenue; and
- There would be minimal change required to the existing price control formulae – in particular, the existing basket weights in the unit-related revenue driver would not need to be reviewed.

Ofgem's proposal that new EHV connections would continue to be treated as an excluded service also goes some way towards mitigating DNOs' risk.

Non-contestable connection charges

We agree with Ofgem's proposal to retain the present price control treatment of connection charges. We also agree that it would not be appropriate to further increase the high risk profile of DNOs by attaching financial penalties to the proposed new service standards.

Other Excluded Services

We support the proposed treatment of top-up and standby charges, non-trading rechargeables and other minor activities, for the reasons set out in the document.

However, we particularly object to the suggestion that revenues associated with out-of-area networks might be included within the price control. These networks have only been built following a highly competitive tendering process and we consider that including them within the price control would represent a significant extension of regulation into a competitive area, for no obvious benefit. Indeed, we believe that inclusion within the price control would distort and possibly undermine competition for such networks. Finally, to the extent that there are any concerns about ongoing use-of-system charges on such networks, these problems could be addressed by some form of relative-price constraint, in common with the position adopted in gas for IGTs.

Business rates

SSE is using all reasonable endeavours to minimise the revised rateable values and therefore the impact on customers. We would expect Ofgem to be doing the same.

However, as Ofgem is aware, once agreed, rates are no longer a controllable cost. At the last price control rates were subject to a pass through, although not in full as the "X" factor continued to apply to the revenue derived from that pass-through. We firmly believe that in the next price control period rates should be subject to a full pass-through and should be outside of the scope of the application of the X factor.

Hydro Benefit

We welcome the Government's amendment to the Energy Bill to enable the GB system operator to provide a subsidy to mitigate the effect of the removal of hydro benefit.

Dealing with uncertainty, new obligations and costs

Traditionally, the price control uses a number of ways to deal with uncertainty. For example, the revenue driver protects DNOs to an extent against changes in costs due to growth in customers and units being different from that assumed and there is pass-through of transmission charges. However, we do not believe that the price control has ever completely recompensed companies for unforeseen costs that arise during the price control period. In a few cases bespoke arrangements have been put in place, for example in the case of supplier failure/bad debts and licence fees. However, an example of where DNOs have lost out is the cost of changes to IT systems and processes as a result of changes in other parts of the electricity market.

We recognise that some future costs are uncertain, however in view of the potential size of some of the costs, and we are thinking here in particular of Lane Rentals and any changes arising from the Customer Transfer Project, comfort letters as suggested by Ofgem are simply not acceptable.

The ENA Regulation Group wrote to Ofgem on 15 April 2004 with a proposal for a formal mechanism for dealing with these uncertain costs, and also for 'logging-up' other unforeseen costs. We strongly support this proposal.

Incentive framework

Ofgem have in the March Policy Paper made a proposal to change incentives which, in our view, represents a radical departure from RPI-X regulation towards a rate-based methodology. This proposal appears to be intended to resolve concerns about definition of costs and incentives, the treatment of capex overspends and incentives for investment deferral. We believe it would significantly weaken incentives to reduce costs and therefore customers would benefit less in the longer term than under the current arrangements.

We have attached to this response (appendix 1) an alternative framework, which discusses the above points and would address the issues facing Ofgem in the present price review, while maintaining incentives to maximise operational efficiency.

Losses

We broadly agree with the basic mechanics of Ofgem's proposed revised incentive scheme for distribution losses. However, we still have concerns about the proposed correction for embedded generation that adversely affects distribution losses – particularly in the SHEPD area. We are also of the view that removal of some of the existing adjustments will increase the volatility of the losses calculation. We take each of these points in turn below.

Embedded generation with adverse effect on distribution losses

We welcome Ofgem's acknowledgement that there is a risk that certain types of distributed generation will increase distribution losses and that therefore this is an issue for the framing of the distribution losses incentive. As Ofgem are aware, this is a significant issue for SSE in the SHEPD area and we have provided Ofgem with indicative information on the level of losses associated with some of the larger schemes, which form part of the DG-BPQ submissions.

Ofgem's proposal is to make an adjustment to reported distribution loss figures based on the Loss Adjustment Factors (LAFs) of the connecting generators. The logic of LAFs is that, where generators increase losses, they are given a LAF below unity. Our understanding is that Ofgem propose to set a "LAF floor" of 0.99 on individual generators to limit the DNOs' exposure to the DG contribution to increased distribution losses: individual DG scheme losses above this limit would be removed from the losses figure used in the incentive mechanism calculations.

This approach may have merit for DNO areas where a relatively small number of DG schemes connect into robust networks and generally offset the demand requirements on those networks. In these situations, site specific LAFs can easily be derived where the circumstances warrant it and could include LAFs below one where increases in losses are expected. We note, however, that the proposed level of the LAF floor appears to have been set such that, on average, **all** the benefit from the DG incentive scheme would be removed before the protection of the LAF floor prevented further financial penalty through the losses incentive scheme. In our view, this is not equitable and the DNO should still have the expectation of some overall benefit from the average cost DG scheme under the combined effect of the losses and DG incentive frameworks. It follows then that the LAF floor should be set at a higher level than 0.99.

However, our major concern with the "LAF floor" approach is that it is not one which would work in the SHEPD area.

As Ofgem is aware, the LAFs for all DG in SHEPD area are set to unity. This policy was extensively discussed with Offer, Scotland, focussing on the difficulties of providing robust LAFs in SHEPD's territory. The point has been accepted that, due to the relatively large volume of DG in SHEPD's area, often situated in parts of the network with low levels of load, the complexity of LAF calculations was not justifiable. Overall, the impact of DG on losses was assessed to be slightly negative in aggregate, a position which again did not justify setting differential LAFs between generators and creating “winners” and “losers”. The engineering studies required would be time-consuming, complex and could only ever provide indicative numbers based on the assumptions used, rather than an ex-ante one-off view of the “right” answer. Often, a theoretical LAF for a particular generator would depend on the background assumptions about the output from other generators in the area and calculations could become circular. It is likely that while developers with “favourable” LAFs would be content to adopt these, there would be continual pressure for recalculation from those developers with “unfavourable” LAFs. Thus a whole industry of calculation and re-calculation of LAFs could be set in train, for no economic gain, if LAFs were to be introduced in the SHEPD area.

An alternative approach for the SHEPD area is therefore required. As we have set out in previous correspondence, our preferred approach is to retain more-or-less the form of the existing distributed generation adjustment. There would probably have to be some guidance from Ofgem on how the adjustment could be made, supplemented by the ability of Ofgem to audit the measurements and calculations behind any changes actually made to the correction term. Failing this, we advocate that an ex-ante allowance is explicitly included in the losses benchmark to take account of the expected increase in losses due to the connection of DG, with the option to reset targets if a materially greater level of losses is actually seen.

Volatility of the losses calculation

Ofgem propose to remove all the adjustments made to the calculation of losses for the purposes of the present losses incentive scheme, apart from the distributed generation adjustment discussed above. This means that the losses figure used for the proposed losses incentive scheme would be (apart from the DG adjustment) the difference between units entering and leaving the distribution system.

While we understand Ofgem’s reasons for seeking to simplify the losses calculation, we are concerned that including EHV units, in particular, in the calculation of losses would result in more volatility and risk for DNOs in the proposed losses calculation going forward. The main reason for the exclusion of EHV units from price-controlled units distributed and from the losses calculation in the first place was the volatility expected in this quantity. EHV sites typically use large volumes of units, but macro-economic factors can lead to gains and losses in the number of sites and in the number of units consumed at existing sites in particular years. There is a separate debate on whether EHV revenues should become price-controlled, but irrespective of the eventual price control treatment, we believe that DNOs should continue to be protected from an underlying volatility in EHV units (and hence losses) in the losses calculations.

Ideally, this would be accomplished by continuing to exclude EHV units from both the units entering and units leaving the distribution system in the proposed losses calculation. We note that Ofgem is minded to give DNOs protection from the additional costs of new EHV sites connecting during the next price control period by continuing to treat such new EHV sites as excluded services. Following this approach in the losses calculation, together with a reasonable allowance for EHV losses in the targets going forward would go some way to reducing DNOs' risk in this area.

Other points

- **Five year retention** – we welcome the clarity of Ofgem's worked examples set out in Appendix 2, which demonstrate that the financial effect of a one-off change to distribution losses would be retained for 5 years. It still appears to us that the algebra to define this will be complex and we suggest that consideration is given to allowing the present value of the benefit or penalty to be rolled up into a one-off calculation in the year concerned or in the following year. This would avoid the complexity of retaining several years' retained benefits/penalties in one year's allowable revenue calculation.

- **RAV Allowance** – we welcome Ofgem's commitment that capital expenditure to reduce losses will be allowed in the RAV after five years. We would welcome further clarity about how this would work in practice.

Price control for metering services

We are disappointed that Ofgem have yet to fully recognise or respond to DNOs' concerns about stranding of assets and operating costs. With regard to assets, we repeat our concern that Depreciated Replacement Cost (DRC) does not protect DNOs against stranding i.e. DNOs would be exposed to more risk than at present. In addition, the detail of the DRC valuation is still to be finalised. Without this, we are concerned that it will it be difficult to judge the increased risk to which we are exposed against the allowed revenue in the Metering price control, and hence it will not be possible to form a final view on the distribution price control proposals. The latter can only be done in the full knowledge of which costs are included and which are excluded.

We remain of the view with regard to the provision of MAP services that to price cap the provision of 'basic domestic meters', together with the use of non-discrimination provisions in relation to other MAP activities, would be simple to apply and would provide sufficient protection to customers. We also see no reason why this should not be a single price cap common to all DNOs. By 'basic domestic meters' we mean a basic single rate domestic credit meter and a basic two-rate domestic credit meter.

We would however not support an additional requirement to have charging methodologies approved. This would introduce, in our view, an unnecessary and bureaucratic 'hurdle' at a time when Ofgem's stated aim is to remove price controls from metering as soon as possible. As noted above, a simple 'non-discrimination' obligation is sufficient to protect customers in addition to the normal protection from competition law. We are also concerned that a requirement on DNOs to have charges approved, but not on other competitors in the metering market, would distort competition.

There is a further complication in relation to prepayment meters. As a DNO we do not need/are not obliged to offer prepayment meters but do so in response to supplier requests. Hence the additional costs of prepayment meters (i.e. the prepayment meter surcharge) is treated as an excluded service. We would propose that it is appropriate to continue to treat the surcharge as an excluded service. We also consider that it no longer needs to be capped as the use of prepayment meters is controlled by suppliers and is no longer a monopoly distribution activity. In addition, there is a real danger that any sub-cap on prepayment meters would distort competition and the development of new technologies.

With regard to MOP, our position remains that MOP is a competitive market. Virtually all MOP services are contracted for by suppliers and there is clear evidence that suppliers are "shopping around".

If a price control were to be applied then in theory an Average Revenue cap would provide best protection against stranded operating costs. These are costs which cannot be avoided as market share falls, for example the loss of efficiency as customer density reduces and the costs of maintaining a trained workforce and geographical coverage to the meet our licence obligation as MOP of last resort. However, an average revenue cap per meter would in our view not work because of the volatility year on year in the work associated with the 'average meter'. For example, meter re-certification programmes can for several reasons vary significantly from year to year. It would therefore be necessary to have the added complication of a 'K' correction factor each year. Due to the distortional effect this would have on prices and competition if this was applied to the metering business; it would have to be recovered through the distribution price control.

Our preferred alternative would be to set an Average Revenue cap per activity, for example per visit. This amounts to the same thing as a price/tariff cap and has attractions in that it is simple to calculate, on a bottom-up basis, and apply. As we have pointed out above the mix of work between activities, for example between re-certs. and new installations, can vary significantly year on year and the cost of a visit can vary significantly, for example between installing a basic domestic meter and a more complex meter. We therefore believe a cap on a single and easily identifiable activity should be used, and we would propose this should be a New Installation. Similarly, the use of a simple non-discrimination provision as suggested for MAP above would be sufficient to protect customers. The question then becomes how DNOs are protected against stranding of costs. The simple and equitable solution, in our view, is that these are identified and allowed to be recovered through the distribution price control.

CHAPTER 4- QUALITY OF SUPPLY

Our prevailing concern at present with regard to Quality of Supply relates to process. The development of output targets/deliverables appears to be disconnected from the work being carried out on cost assessment and setting allowed revenue. We are therefore concerned that it will not be possible for us to judge properly the Initial Proposals planned for June without knowing what outputs are expected from the opex and capex allowances.

Our second major concern is that DNOs have had their exposure to financial penalties and risks increased significantly through, for example, Guaranteed Standards, IIP and the Interim Arrangements for storm compensation. In the absence to date of any increased reward to compensate for this additional risk, we continue to propose that all these exposures should be capped in aggregate within the 2% p.a. cap currently in place under IIP.

Our third main concern is with the seemingly slow progress on developing the disaggregation work and the consequent benchmarks. We cannot support the benchmarks as currently derived, and we explain this below. However, in our view it is more important that the targets set are company specific reflecting the opex and capex allowances.

Guaranteed and Overall Standards of Performance

Guaranteed standard on supply restoration

We support the proposal to separate GS2 to cover only normal weather and that severe weather will be covered by the storm arrangements. We also support retaining the existing payment structure.

Automatic payments

We are firmly opposed to the proposal to extend GS2, by introducing an equivalent penalty to cover all consumers off supply for more than 18 hours where payment is not made, for the following reasons.

- Losses of supply longer than 18 hours generally arise from incidents on the LV networks, as these will tend to involve extensive excavation and repairs before reconnection is possible (especially on non-backfeedable Consac networks). These incidents will affect certain parts of a LV network - perhaps a single phase or a sub-feeder burn off. Paying all possible consumers who may have been affected would therefore mean that compensation would be paid erroneously to customers who were not affected or who were not in residence at the time of the incident.

- Incidents that extend beyond 18 hours are almost always as a result of difficult network configuration or connectivity, and not a lack of effort or focus or even negligence on our behalf. We feel they are not in management control and therefore we should not be penalised more severely than we are under the present guaranteed standards, which are already supplemented by ex-gratia payments where appropriate.

- More generally, semi-automatic payments would result in significant additional costs and risks for even efficiently operated DNOs. The additional costs would not only arise from greater payments, but also from the additional work in contacting customers and liasing with the relevant supplier. If Ofgem proceed with this proposal DNOs would therefore clearly require an explicit cost allowance in respect of these efficiently incurred costs. In addition, to mitigate the open-ended risk to DNOs, we firmly believe that all payments under this and indeed all standards should be covered by the overall 2% liability cap including those arising from IIP.

Compensation for business customers

We welcome the conclusion that it would not be appropriate to differentiate between domestic and lower voltage connected business customers. However, we would regard the proposed extension of compensation for consumers connected at HV as wholly inappropriate. As above, this would raise additional risks for DNOs and also additional cost even for efficient DNOs. These costs would need to be reflected in the "baseline" cost allowance under the price control. In addition, it is important to note that HV business consumers have to some degree chosen their 'quality of supply' when they signed their connection agreement. For example, if they choose not to pay for a switched alternative supply, then they should not receive compensation if they are affected by an incident where an alternative supply would have enabled much more rapid restoration. Ofgem's proposals would thus distort HV customers' choices in connecting to the network, which would raise issues about cross-subsidy between customer groups. For these reasons, we continue to believe that these consumers should not have been part of the willingness to pay survey.

Priority service consumers

We welcome the conclusion that no new standards of performance are appropriate for priority service customers, for the reasons set out in the document. We are also keen to work with Ofgem to explore the issues around the existing priority service register. For example, in our view more work is required to develop a reliable and robust database for priority consumers and effective change management of the data. However, if Ofgem do conclude that further licence conditions are necessary for DNOs, then the additional cost of meeting those obligations must be included within the operating cost allowance under the price control.

The role of the overall standards of performance

We support discontinuing the Overall Standards. However, we urge Ofgem not to replace them with onerous reporting requirements through IIP unless demonstrably necessary. The reporting requirements under IIP are already extensive.

Other amendments to the Guaranteed Standards of Performance

We have said on many occasions that we believe the Multiple Interruption Guaranteed Standard (MIGS) is a flawed Standard, as it assumes an ‘acceptable’ failure rate. The intention of Guaranteed Standards was always that DNOs should be able to avoid failure by efficient management action. This is not the case with MIGS as it will always be uneconomic to provide an ‘urban’ quality of supply to remote rural regions. It has also not been demonstrated to us that urban customers are prepared to further ‘cross-subsidise’ rural customers, who are already paying less than the cost-reflective charge. In our view the increased focus that the October 2002 storms, and the Press reaction, brought on quality of supply will result in many more claims under MIGS going forward. Our strongly held view continues to be that MIGS should be removed. If not, it should certainly not be tightened and DNOs should be allowed full pass-through of compensation and administrative costs incurred. In addition, we believe that the unique circumstances of the Highlands and Islands of Scotland should be recognised by an exemption from the MIGS, consistent with the interim arrangements for storm compensation.

Reviewing IIP

Provision of disaggregated interruption data

We support the disaggregation work that has been carried out to date and recognise that the reporting requirements need to collect this further information. However, we are concerned at the seemingly slow progress on developing the disaggregation work and the consequent benchmarks. As we have said before, we cannot support the benchmarks as currently proposed, as the disaggregation work is in our view significantly incomplete. For example, it still does not take account of differences in tree cover between DNOs (a main cause of faults) or third party damage (another major cause of interruptions in SEPD’s area), the proportion of longer networks or the problems being experienced with Consac cable. We would welcome Ofgem’s response to this particular issue.

Worst-served consumers

As noted above, we would wish to see MIGS removed. However, we recognise that reporting of multiple interruptions through IIP could provide useful information in improving quality of supply to all customers. Our main concern relates to SHEPD’s region and an alternative suggestion could be that the Highlands and Islands of Scotland are excluded from MIGS as has been recognised in the interim arrangements for storm compensation.

Connections

It would seem more sensible, rather than simply transfering the existing reporting requirements to IIP, that the Standards applying to Connections should be reviewed from first principles, only retaining those absolutely and demonstrably necessary.

Form of the incentive scheme

We support the process of annual rewards and penalties, which should be symmetrical. However, it is important that the force-majeure exclusion remains. It will also be necessary to set the target so that an averagely efficient DNO would be neutral to the scheme. This means that inefficient DNOs would receive a penalty and the industry leaders a reward under the scheme. In addition, while we support the overall 2% cap on liabilities for IIP, we continue to believe that all payments under the quality of supply regime should be brought under the scope of an overall cap. This will have implications for target setting, since the overall balance of cost allowances and targets will need to be skewed to ensure that an averagely efficient DNO will be neutral to the overall quality of supply package.

Forecast of planned and unplanned interruptions

We are not clear what Ofgem hope to achieve by adjusting the weights for planned and unplanned interruptions. We are also concerned that any change in the weights (in either direction) could produce perverse incentives. In any event, it is vital that any weighting should take into account the recent trends in DNOs' planned CIs and CMLs, and also future workloads based on increasing capital programmes.

Audits and adjusting data for inaccuracy

The important factors to consider regarding audits are:

- The ratio of incidents in the sample should be based on the contribution by voltage;

- There are still inconsistencies in the audit process that need to be driven out. Therefore the existing audit process should be retained in the short term; and

- The aim should be to move towards a process where Ofgem select ~100 incidents, the DNO audit them and Ofgem the selects 10% of the 100 incidents to verify the DNOs view of accuracy.

We strongly disagree that performance data should be adjusted for inaccuracies identified by the audits, which lie within the threshold tolerance. It is important to consumers, Ofgem and DNOs that the performance data is frozen as soon as possible after the end of the year, and not adjusted many months later. There could also be a loss of consistency over time if results are modified by differing amounts each year.

Target setting

As noted above, although we fully support the process of disaggregation, we believe the process is not robust enough to generate benchmarks. Anomalies specific to individual DNOs must be taken into account. In addition, it is vital that the targets set by Ofgem are consistent with DNO investment plans and are consistent with an averagely efficient DNO being neutral to the overall quality of supply regime.

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

We still do not believe that Ofgem's proposal is necessary, given as the document itself notes, that DNOs do not know what their targets are for 2005/06 and hence the effect of rolling forward any CIs and CMLs. It is interesting to note that to take advantage of this mechanism, the date by which DNOs had to commit has already passed.

Frontier performance

We do not agree with this additional reward which in our view is clearly the same as re-opening the current price control. There is a real danger that any reward under this scheme could be seen as arbitrary, since it was not flagged up as a possibility at the previous price review and has not therefore had any effect on DNO incentives or behaviour. We would also welcome confirmation that a DNO which not only meets its DPCR3 targets but is also a best performer on quality relative to the disaggregated benchmarks will be rewarded twice (i.e.under this scheme plus IIP).

Network resilience

We note that work continues to try to develop measures and incentives for network resilience and we will continue to work with Ofgem on this, recognising the difficulties in developing a robust "formulae" approach. We also note that work is ongoing to develop the interim arrangements for compensation in storms. As noted above, we are becoming increasingly concerned that the existing quality of supply incentives, plus Ofgem's proposed enhancements would expose DNOs to excessive cost and risk. Against this background, we would not support the proposed enhancements to the existing interim storm compensation regime.

We would also require a much greater degree of pass-through for an enduring storm compensation arrangement. In particular, any scheme must ensure that an averagely efficient DNO is neutral to customer compensation in an "average" year. Otherwise, the DNO would earn less than the cost of capital under these arrangements other things being equal. In setting enduring storm compensation arrangements post 2005 – whether enhanced or not – it is absolutely vital that Ofgem recognise that this will be the case.

Finally, we do believe that the materiality condition is perverse. In effect, it means that DNOs that have invested in resilience are less likely to qualify for cost pass-through than those DNOs that have not. The "lower rate" for any storm compensation arrangements should therefore be designed in terms of fault only.

Incentives for telephone response

Overall, we believe that the telephone survey is bureaucratic, costly, serves little purpose and should therefore be discontinued. In addition, we continue to believe that this Data Protection requirement to inform customers that their call may be rewarded for the purpose of the survey acts against good customer service (particularly in emergency situations). It is clear that performance of all DNOs is converging, and to a level which is superior to other industries and other countries.

In the event that the survey is to continue, our more detailed comments are as follows,

- **The survey sample** The technology to capture these callers is complex, and we believe our systems are unable to achieve this requirement without significant investment in new telephony technology.

- **Survey questions** We would support any simplification and rationalisation of this survey.

- **Combining quality and speed of telephone response** Much effort and research has been expended in an attempt to measure the speed of telephone response. The diverse output performances between DNOs confirm that the actual speed of response is not measurable to a robust standard, and as a result Ofgem have placed DNOs into two categories based on their technologies and processes.

  We support the initiative to revise the questions in the Accent survey to gain customers' perspective on speed of response, and suggest it would be appropriate to cease reporting the speed of response statistics, thus saving wasted resources in the DNOs and Ofgem.

- **Form of the incentive scheme** While the survey questions are being changed in style and content, it would not be appropriate to move away from a comparative scheme, as DNOs individual baseline performance has not been established to the new standard. One option to consider is to accept that any score >80% satisfaction represents a good performance, and all companies above that threshold should receive a reward.

Environmental outputs

We support Ofgem’s proposal not to set financial incentives for environmental outputs during the current price control period.

We believe that reporting the number of 'top ups' of SF_6 is not an appropriate indicator of loss of gas, as each DNO will have their own topping up regime. The volume of SF_6 purchased in an average year would be more robust.

General discretionary award

We support a general discretionary award for the future price control period. However, its motivational qualities will diminish if it is not attainable by all companies. Perhaps the reward could be shared on a category basis, for example best priority service or best communication with the media in a storm, to try and develop best practice. In any event, if the discretionary award is to motivate good practice, some indication of the likely criteria for making such an award would be needed at the time the price control is set.

CHAPTER 5 - DISTRIBUTED GENERATION, INNOVATION FUNDING AND REGISTERED POWER ZONES

We have noted in previous responses our view that it is unnecessary for Ofgem to introduce a complex scheme in order to incentivise DNOs to connect distributed generation (DG) in an efficient manner. We will not repeat all these points here, except to reiterate that, in our view, the form of the incentive scheme currently proposed by Ofgem will, by its nature, incentivise DNOs to delay making appropriate investment to facilitate the connection of DG, which in turn may have implications for the Government's targets for renewable generation.

Detailed comments on the proposed scheme

We welcome the clarification that Ofgem has provided in a number of areas since the last information published on the proposed scheme. In our view, one of the over-riding principles for a successful incentive scheme is that there should be a fair balance of risk and reward for each DNO relative to the costs, which are likely to be incurred. We note that some measures have been put forward to reduce the risk of the scheme for DNOs but we still have some concerns in this area and also in the proposed remuneration for operating and maintenance costs. We comment on each of these issues in turn and then provide more general comments below on the other proposals in this chapter of the document.

Controlling DNO Risk

Higher than average expected unit costs

We note that Ofgem has recognised that the SHEPD area has a higher base of average DG connection costs than other DNO areas. We also note the comment of Ofgem's consultants in the DG-BPQ analysis document that this is consistent with their expectations, given the large number of projects wishing to connect in remote parts of the network. Against this background, we welcome the higher allowance for SHEPD. It should however be noted that this additional figure has been set at a level consistent with SHEPD earning the cost of capital (and no higher) if all of the anticipated MW of distributed generation materialises.

Outturn costs higher than expectation

We support Ofgem's proposal to introduce a floor and cap on DNO returns under the incentive scheme. This should reduce the extremes of the returns seen on an average basis under Ofgem's previous proposals. We would however like to see further clarity from Ofgem on how and when the assessments of actual rate of return from the DG portfolio will be made. The statements in paragraph 5.31 still seem a little vague and suggest that adjustments to bring overall returns back within range will be made through the incentive rate applicable in the following price control period. In our view, a lump sum adjustment to allowable revenue would be preferable, as it would deal with previous over- or under-recoveries of revenue in a defined manner rather than one which is again subject to further uncertainty.

High cost schemes

We also support a different treatment for "high cost" projects. As we have argued previously, without a limit on the cost/kW of schemes that are included in the incentive scheme, DNOs would face an open-ended risk.

However, the proposed cap of £200/kW still allows very expensive DG schemes to be covered under the incentive proposals. There are two reasons for an increase in the numbers of above-average cost schemes compared with the DG-BPQ forecasts – particularly in the SHEPD area. One is that there are many schemes which have previously been put off connecting due to the "deep connection" policy: developers could reapply for connection for these schemes if the proportionate reinforcement costs they pay under the new rules are favourable. If they do reapply on this basis, the chances are that the reinforcement to be funded by the DNO will be "expensive".

Secondly, our experience with DG developers in the SHEPD area has been that, in many cases, reinforcement costs are kept at economic levels through the developer accepting non-firm connection arrangements. For example, for a DG connection between two geographically distant sub-stations, reinforcement will typically only cover the link from the DG scheme to the nearest substation; if faults occur on this reinforced route, the DG scheme will have to stop exporting. If, under the revised arrangements, developers did not see the economic cost of firm arrangements, they are likely to require the additional reinforcement to be undertaken to give them a "firm" connection, thus undermining the economic approach we have developed in the past to these type of connections. We are concerned that if the range between the "average cost" and the "high cost" cap under the DG incentive scheme is too wide, SHEPD could become liable for additional and uneconomic reinforcement costs, that significantly push up the outturn average reinforcement cost.

Our calculations suggest that the DNO's rate of return for a project with a £200/kW reinforcement cost would be 3% to 4% depending on the proportion of expected MW that materialise. Instead of this exposure to low rates of return, we believe that the "upper limit" should be derived by considering the £/kW reinforcement cost at which the incentive rate set by Ofgem (assuming that 100% of the expected MW materialised) provides a total project return at the "floor" rate of return. Our calculations suggest that this would be around the £100/kW mentioned in Ofgem's earlier documents.

Once an upper limit has been defined for inclusion of DG schemes within the main DG incentive scheme, we believe that it should be open to DNOs to initiate an alternative process for dealing with the investment requirements of DG schemes whose reinforcement costs take them above the upper limit. We propose that DNOs could bring forward such schemes for discussion with Ofgem. This could involve non-firm connections or arise where the associated reinforcement itself is judged to have benefits to the system or to future potential DG schemes. In the latter case, the sort of reinforcements we have in mind are sub-sea cable links and extensive 33kV circuit upgrades. If Ofgem agreed with the DNO's assessment, the reinforcement element of the connection would be fully funded on the DNO's RAV via a specific term in the DG incentive price control formulae. This treatment could also be applied to strategic investments and in fact avoids making a distinction between "strategic" and “expensive” reinforcement. We note that Ofgem’s consultants on the DG-BPQ commented that companies have taken different approaches to the split of costs between these categories.

In the above approach, Ofgem would, of course, retain the right to refuse to allow such investment. The situation would then default to the one outlined in the consultation paper whereby the generator seeking connection would be required to fund the additional costs of the connection beyond those which have been accommodated by the DNO in reaching the upper limit of £/kW for the scheme. In this context it would also be helpful if Ofgem clarified that the generator would also be required to fund the sole-user and additional reinforcement O&M costs above this limit.

However, by providing for the possibility of this alternative route, Ofgem would be opening the door to a potentially more flexible and timely response to the investment uncertainties associated with the macro-development of DNO networks against the background of the government’s commitment to increasing levels of DG. We recommend that this “parallel route” for accommodating DG is given further consideration.

Appearance and continuation of expected DG MW

A further major area of risk for a DNO would be that the MW expected from a particular DG scheme did not materialise or were delayed. Such delays or non-appearance of the DG MW would be for reasons outside the DNO’s control and wholly associated with the risk environment in which DG developers operate. The risks include delays or refusal for planning permission, delays in required transmission capacity becoming available and economic considerations such as the value of renewable obligation certificates. It would not be reasonable, once DNOs had invested to facilitate a DG connection, for their return on investment to be at risk of being lower than the cost of capital due to these external risks.

In this context, it is worth setting out some detail of the current connection process for DG developers, where a deep connection charge is payable by the developer.

Step 1) preliminary discussion between DNO and DG developer on feasibility etc;
Step 2) developer provides all the information necessary for DNO to offer terms for connection;
Step 3) DNO provides an “offer for connection” to developer;
Step 4) Developer accepts and signs “offer for connection” and pays a proportion of the expected non-contestable cost of the connection;
Step 5) DNO progresses non-contestable connection works, requiring staged payments as work is initiated. Developer also progresses contestable works (which may be done by DNO), and other non-electrical requirements of the connection such as planning permission;
Step 6) Once developer is ready to connect and conditions precedent have been fulfilled, a “connection agreement” between DNO and developer is signed and the connection is energised; and
Step 7) At a time of the developer’s choosing, the DG scheme is commissioned.

The only change to the above process, once the proposed "shallower" connection charging approach is adopted is that, at Step 5, the DNO would have to progress some element of the non-contestable connection works without receiving payment from the developer. Instead, the hybrid mechanism would provide the funding for the portion of the non-contestable work not paid by the developer in the connection charge.

We are firmly of the opinion that the MW for the £/MW element of the incentive scheme should be counted from step 4, when the developer signs the "offer for connection" and makes a financial commitment to the project. The MW should then remain in the count for the incentive scheme for 15 years from that point, regardless of the fortunes of the actual DG scheme. This would match the start of the incentive funding to the year in which the DNO costs are incurred and would be clearly auditable. It would also mean that the DNO was not exposed to the counterparty risk of DG schemes.

If DG schemes were not to remain in the incentive term for the full 15-year period, DNOs would, in effect, be exposed to the same financial risks as wind farms. However, since the developer would not pay the full cost of connection at this stage, there would be a residual risk that some schemes would not materialise even after accepting the connection offer. To mitigate this risk, consideration might need to be given to requiring developers to pay a higher proportion of their connection quotation up-front. The downside to this approach is that it might not maximise incentives to utilise spare capacity. That is, if the £/MW term continues for 15 years even if the windfarm closes earlier, there is a risk that the DNO might not seek to encourage alternative, new developers to use the same site. However, we believe that this risk can be overcome by also allowing the DNO to retain the £/MW term for such second-comer developments, possibly at a lower rate. The overall cap on the hybrid mechanism would also ensure that returns to the DNO under this approach were not excessive.

Forecast risk

Ofgem acknowledges that the DG incentive may increase the likelihood of mismatch between revenue flow and revenue entitlement, leading to an increased risk for DNOs of a non-neutral recovery position against total allowable distribution revenue. We agree with this assessment and suggest that it would be appropriate, at least in DNO areas with significant quantities of DG expected to connect (such as the SHEPD area), for the suggested deadband discussed in the rebates decision document to be increased from the proposed 2% to 4%.

Operating and Maintenance Costs

The consultation document expands Ofgem's previous comments on the recovery of O&M costs and, in our view, the proposals in this area fall far short of an equitable approach. Our comments are as follows:

Risk on cost recovery

Ofgem has provided no justification for the continuing proposal to link the recovery of O&M costs purely to the £/kW incentive term. This makes the recovery of these costs much more risky than the recovery of the prime capital costs associated with DG. In our view, there is no reason why there should not be equality of treatment of these two types of cost under the incentive scheme i.e. O&M costs should be subject to 80% pass-through with only 20% linked to the £/kW incentive rate.

Higher than average expected unit costs

The principle of £/kW recovery of O&M calculated on an average basis across companies penalises companies with higher than average £/kW costs. It has already been acknowledged that the SHEPD area faces a higher range of unit costs than other DNO areas. Logically, there should therefore also be a higher £/kW allowance for O&M.

Inclusion of sole user asset costs

We are concerned to note Ofgem's suggestion that the O&M associated with sole user assets will also be covered in the £/kW rate. Given the nature of SHEPD's territory, there is a significant risk of relatively high cost sole user assets (e.g. long system extensions to link remote sites with worthwhile renewable energy potential to the existing distribution system) dominating the mix of DG connections which actually occur. This is on a forecast base, which is already at the higher end of the DNO range for sole-user costs. This effect would be mitigated, with an 80% pas-through of the O&M costs and a realistically higher £/kW cost for O&M.

Level of O&M allowance

Our final point relates to the percentage allowance that Ofgem uses to convert the £/kW capital cost of asset investment to a £/kW allowance for O&M. In this and previous consultation documents, Ofgem has referred to DNOs' annual O&M costs as being generally in the order of 1-2% of capital costs per year. Given the view expressed by Ofgem's consultants in the DG-BPQ analysis that there will clearly be additional operating costs associated with DG, there seems no justification for Ofgem taking a percentage figure at the very lowest point of the 1-2% range. In our view, a figure of 2% would be appropriate.

Other points

While our main comments on the DG proposals are set out above, there are several other areas where we have comments on the operation of the scheme. These are set out in turn below, following the order in which they are raised in the document, where appropriate.

Funding the DG incentive scheme revenues

Ofgem has suggested that the pass-through element of the scheme should be funded on an annuity basis over an assumed asset life of 15 years, starting in the year after the expenditure is incurred. Ofgem also intends that the revenue generated by the hybrid DG incentive scheme would largely be recovered from generators connecting to the distribution system after 1 April 2005 through generator distribution use of system charges (GDUoS). Ofgem has suggested that a benefit of an annuity approach to the pass-through element of funding would be a more stable GDUoS tariff.

We would prefer not to move away from the traditional and well understood RAV funding. With RAV funding, annual allowable revenue consists of depreciation plus a return element calculated by applying the agreed cost of capital to the net RAV value. An annuity approach would provide less cash in the early years of the investment cycle than the RAV funding approach, which would significantly increase regulatory risk for the DNO. Although the annuity approach might superficially appear to have the benefit of a more stable revenue requirement, in reality, this effect would be masked by the changing level of investment from year to year.

The amount of new DG MW connected for a given reinforcement expenditure will vary from year to year. There will also be variability in forecasts compared with actuals, which will lead to correction factor issues. Thus, there are a number of factors which will influence the volatility of £/MW GDUoS charges and an annuity approach to allowable revenue would not, per se, achieve stability in generator charging.

An annuity approach would therefore not provide the stability in GDUoS that Ofgem are seeking and could lead to other issues for DNOs in terms of project finance and regulatory uncertainty. For these reasons, we would not support moving away from a traditional RAV-based calculation. However, we would agree that stability of GDUoS charges is important. We therefore support Ofgem's proposal that pass through costs are funded by demand customers in the event that expected DG volumes do not materialise or cease to operate before the investment is fully depreciated, although we consider that this should also apply to the incentive element of the scheme. There would also be a benefit for the stability of generator charges if these were capped, with any outstanding balance of DG funding requirement put into demand charges. We note that trigger levels for such a transfer will be discussed as part of the structure of charges project.

Locking in the incentive rate

We welcome Ofgem's commitment to maintaining the incentive rate for the life of the relevant assets that have actually connected, even though the incentive rate itself may be reviewed for future schemes at the time of the next price control. We consider that this commitment should apply to all elements of the scheme, including the O&M charge rate, which Ofgem has specifically excluded. The incentive mechanism will have a life over three different price control periods and Ofgem should provide a commitment to the finalised DG incentive scheme proposed as part of the 2005 price control for the 2010 and 2015 reviews.

Microgeneration

Ofgem raises the question of whether the DG incentive scheme should apply to microgeneration. In our view, all types of DG including microgeneration and small CHP schemes should be included in the scope of the incentive scheme so that DNOs are broadly incentivised to facilitate all types of DG. If significant reinforcement it unexpectedly required due to the requirements of widespread microgeneration installations, then this is the situation in which we would envisage a discussion taking place with Ofgem about the funding of "expensive" or "strategic" reinforcement as discussed above in the section on Controlling DNO Risk. Indeed, if the impact on a DNO's network was particularly severe, then such a situation might provoke use of the "general re-opener" clause that we advocate is included in the terms of the incentive scheme (see point on this below).

Network access incentive

We have concerns with Ofgem's proposals for incentives on ongoing network access that have been mentioned in publications on the DG incentive and also within the documents concerned with the development of distribution charging. Ofgem refers to the Renewables Directive (2001/77/EC) as justification for this type of "compensation" mechanism. However, the Directive only comments that financial compensation "**may**" be included in arrangements to ensure that transmission and distribution operators guarantee the output of generation from renewable generation as set out under Article 7. It does not actually require a compensation regime.

There is no doubt that the payment of compensation to generation sites would increase the potential financial liability of DNOs, particularly in areas with large amounts of MW forecast to connect, and this factor would need to be considered as part of the price control settlement (i.e. DNOs would need a baseline "allowance" for anticipated costs).

The details of Ofgem's proposals in this area seem arbitrary and we do not support the development of this type of incentive mechanism. If Ofgem continue to develop such a mechanism then it would be vital that the overall risk to DNOs were brought within the framework of an overall cap on the DNOs' exposure to the combined effect of the differing performance incentive schemes.

Definitions and reporting

We agree that there will be a need to have clear definitions for the purpose of reporting performance under the DG incentive scheme and agree that a good starting point for those definitions would be those used in the DG-BPQ. We would hope that the complexities and volumes of paperwork associated with the IIP incentive scheme could be avoided.

Cost of capital

Ofgem have based the indicative figures on an assumed cost of capital of 6.5% pre-tax. While it has been useful to see illustrative figures for the parameters of the proposed hybrid scheme, we believe that 6.5% is insufficient for the cost of capital. As a consequence, specific figures for the incentive scheme would need to be revisited to ensure consistency with the other elements of the price review.

Tax treatment

The financial parameters of the incentive scheme have, to date, been discussed in pre-tax terms, consistent with the present price control framework with references, for example, to the current pre-tax allowed cost of capital of 6.5%. In the proposed new framework where overall allowable revenue is calculated on a post-tax basis, a forecast of DNOs' actual tax liability is taken into account as an operating expense. The implication for the DG incentive scheme is that the tax liability associated with the incentive revenues will have to be considered explicitly in setting the incentive parameters.

In our view, there are 3 main options:

1. Keep the incentive calculations on a pre-tax basis, but estimate an average marginal tax wedge across companies in arriving at the pre-tax cost of capital;
2. Move the incentive scheme to a post-tax basis, with a pass-through of DNOs' actual marginal tax liability in respect of the incentive scheme revenues;
3. As above, but include within the incentive calculation an ex-ante view of what a DNO's marginal tax liability will be on a £/kW basis.

In our view, moving the incentive scheme to a post-tax basis will add further complexity to an already complex scheme. We also do not believe that it will be possible to forecast specific tax liabilities under the scheme, since the volume of DG (and hence additional revenue) are subject to considerable uncertainty. As a consequence, we would advocate option 1. That is, we believe that the simplest and fairest approach would be to apply a pre-tax cost of capital in calculating the scheme parameters, assuming a marginal rate of tax (i.e. tax wedge) of 30% for all companies. However, in doing so, it will be necessary to use the pre-tax figure which is consistent with the final allowed post-tax cost of capital (rather than the 6.5% used hitherto).

General re-opener

It is clear that there is substantial uncertainty about how the hybrid scheme will operate in practice. To reflect that uncertainty, we consider that there is a strong case for the licence condition associated with any hybrid scheme to contain a general re-opener, which would allow a DNO to appeal to Ofgem for a re-opening of the price control. The re-opener clauses should also contain rights of appeal to the Competition Commission in the event that Ofgem refused the DNO's application. In the light of the substantial change that the hybrid scheme represents to traditional RAV funding, we would not be comfortable with new arrangements that did not include such a re-opener to allow for unforeseen situations and risks.

Revocation or substantive reform of ROC scheme

In addition, we consider that it would be unreasonable to expose DNOs to the Government/ legislative risk inherent in the ROC scheme. In particular, since the hybrid mechanism remunerates DNO investment over a number of years (through the £/MW) we believe that the licence conditions should provide for a specific re-opener in the case of a fundamental shift in Government policy on renewables, such as a major reform or revocation of the ROC scheme. In these circumstances, we believe that 100% RAV funding should be provided for any outstanding investment and we believe that the licence should explicitly provide for this eventuality.

Conclusion

To summarise we welcome the fact that Ofgem have suggested a number of significant improvements on the initial scheme – much progress has been made since the previous consultation paper. However, we believe that to achieve an acceptable incentive scheme along the lines proposed, Ofgem should:

- Set a more reasonable method of recovering the O&M costs associated with DG schemes than the £1/kW currently proposed;
- Reduce the proposed cap on high-costs projects to £100/kW and allow a "parallel route" for DNOs to discuss RAV funding for expensive /strategic projects with Ofgem mid price control;
- Acknowledge that the appropriate point to count DG MW for the incentive scheme is at the time that a developer accepts and signs an "offer for connection";
- Allow the DG MW to be counted for the full 15 years from the start point to avoid DNOs being exposed to the counter-party risk of DG schemes;
- Commit to a RAV-funding style approach for recovery of the DG pass-through costs;
- Explicitly bring the scope of any network access incentives within the scope of an overall cap on DNOs' exposure to the combined effect of the performance incentive schemes and standards;
- Explicitly allow for a price-control re-opener in respect of the DG incentive, both in the general case of unforeseen circumstances and in the specific case of a change in Government policy with respect to instruments of renewable energy policy such as ROCs;
- Clarify how the average DNO return on DG investment will be assessed for the purposes of the cap and floor, and confirm that any adjustment will be made in a defined manner;
- Consider increasing the proposed "deadband" around target allowable revenue recovery to reflect the uncertainties associated with DG allowable revenue;
- Provide a commitment to the operation of the finally defined incentive scheme across the three price control periods involved;
- Clarify the reporting arrangements for the scheme.

Registered Power Zones (RPZs) and Innovation Funding Incentive (IFI)

We welcome the increasing clarity around the manner in which these incentive schemes will be expected to work.

IFI

In relation to the Innovation Funding Incentive (IFI), we continue to believe that there will not be much incentive for DNOs to come forward with projects unless the percentage of pass-through funding is virtually 100%. Nonetheless, if the funding level can be addressed, we support the commencement of this type of incentive at as early a date as possible. In our view, the criteria for IFI projects should follow from the scope and aim set out by Ofgem in section 5.50 of the document.

We accept that the IFI scheme will have to be supported by transparent public reporting by DNOs of the schemes that they undertake. However, we would not wish to see undue bureaucracy in the development of a common "good practice guide" across all DNOs. In particular, it would be unfortunate if the establishment of such guides were to hold up the implementation of potential schemes on an interim basis.

RPZ

- We support the framing of the incentive for RPZ schemes to be a doubling of the relevant £/kW element of the main DG incentive scheme. However, given the depreciation life of the investments that might be considered for these schemes, we advocate that the additional premium is available over the full 15 years of the main DG scheme rather than limited to 5 years. The greater the revenue stream associated with successfully connected MW under RPZ schemes, the greater will be the incentive for DNOs to seek out marginal opportunities and methods of connecting additional MW.

- We do not support the proposed cap of £0.5m per DNO per year for the additional revenue that a DNO can claim for RPZ projects. A figure ten times this amount should be considered.

- Given that RPZ projects are likely to build up gradually over the price control period, we support the suggestion of a carry-forward mechanism for "allowable" RPZ funding i.e. "headroom" under the cap, if not used one year could be allowed in following years.

- It seems appropriate for the cost of RPZ projects to be met in the first instance through GDUoS charges. However, that funding should be subject to the overall cap on charges met by generators, as discussed in the Other Points section above.

- The criteria for RPZ projects appear to have been set out in Ofgem's RPZ proposal box in the consultation. There should be no further narrowing of the definitions. With the help of a Panel, Ofgem would register schemes on the basis of the proposals brought forward by DNOs.

- As with the IFI scheme, we would caution against too much bureaucracy to be associated with the scheme. In particular, the suggested development of a "good practice guide" should not be allowed to delay the potential introduction of valid RPZ projects.

CHAPTER 6 - ASSESSING COSTS

We will be responding separately and in detail to Ofgem's recent letter to each DNO about normalisation, benchmarking and the process for determining the opex and capex allowances. Therefore, we have restricted our comments below to our main concerns about the broad issues raised in the consultation paper.

Review of forecasts

It is clear that DNOs have made different assumptions in compiling opex and capex forecasts. For example this is apparent in opex between the CE Electric companies which appear to have omitted any uncertain or unknown costs going forward, (e.g. Lane Rentals and ESQCR), and the EdF companies who seemingly have included an estimate of the main potential risk or cost to which they may be exposed.

Similarly, it is also clear that companies have compiled their capex forecasts using different assumptions. In particular, the EdF companies have included in the base case proposed expenditure which other companies have included in the DNO case, for example fluid-filled cables, and have taken a different approach to risk acceptance than for example SSE. Whereas we have submitted capex forecasts, which we believe imply an acceptable level of risk for a DNO to bear, EdF seem to have been more risk averse.

Above all, it is vital that Ofgem set allowances which assume the same level of risk for each company, and that any change from current levels is reflected in the cost of capital or through other mechanisms for dealing with uncertainty to which we have referred above.

Finally, with regard to forecast costs, we still do not regard the Quality of Supply cases as of any value. They are based on Ofgem assumptions and sensitivities which do not take into account what customers expect, or are willing to pay for. We are concerned that Ofgem believe they can simply use the quality of supply scenarios to "flex" the base case. This is not the case and we continue to advocate the DNO case as the correct starting point.

Normalisation of costs.

Clearly, the normalised base operating costs derived are insufficient to cover even the frontier company's costs. The main issue still to be resolved therefore is the level of costs to be added back in to each company's normalised costs for pensions, storm costs and insurance, inter-company margins, future increases in/additional costs and the efficiency adjustment to be applied. We will be setting out in our response to Ofgem's 22 April letter, our view of future cost pressures specific to SEPD and SHEPD, and in this response we therefore focus below on how to apply the efficiency adjustment.

We have already referred to our paper on Setting Incentives to Maximise Efficiency, attached as Appendix 1 to this response. This, we set out our support for the use of "average costs" in setting allowed opex going forward, where by future allowances are set based on the average DNO cost as indicated by the benchmarking exercise (the regression line). We continue to strongly believe that this has the best incentive properties, best mimics a competitive market and in the end maximises the benefit to consumers.

This is relatively straightforward to achieve and would involve the following key steps.

(i) The DNO opex figures would first need to be adjusted for the 132kV network in Scotland, differences in capitalisation policies and regional adjustments (London and North of Scotland only, as per the last review). There would be no need for a detailed "normalisation" exercise which Ofgem are presently conducting and which is not shedding any greater clarity on differences in cost across companies despite months of work. For example, we calculate that Ofgem's analysis has only statistically explained an extra 3% of the difference in performance across DNOs despite taking £120m out of the combined cost base (which must presumably be added back at the end of the process).

(ii) Calculate a regression of operating costs plus total fault costs, using adjusted customer numbers, as at the last review. Given differing treatments of fault costs, we agree with Ofgem that this is the only credible (and statistically robust) basis for carrying out the relative efficiency assessment.

(iii) Future allowances would then be set on the basis of the average cost, with an assumed standard percentage capitalisation of the average fault costs (say 50%), less Ofgem's estimate of future efficiency. However, if an efficiency adjustment were made, DNOs would require a separate allowance for the estimated cost of achieving that efficiency (Ofgem would be taking the benefit of those savings up-front, so customers should pay the costs of making those savings "up-front"). It would also be necessary to make specific adjustments to recognise the cost increases facing all DNOs, particularly pensions.

(iv) To avoid any incentive to artificially capitalise future opex, Ofgem should make clear how the capitalisation policies are to be applied *going forward*. Ofgem's March paper seems to dismiss that this is possible. However, much has been achieved in the work on Regulatory Accounting Guidelines and we believe that work could go far in ensuring companies are applying similar policies and without involving detailed regulatory auditing by Ofgem. As an extra precaution Ofgem could ask all DNOs to confirm that their capex plans are consistent with the forward-looking capitalisation policy.

Mergers.

We agree that it is not necessary to adjust DNOs' costs for merger savings for the purposes of benchmarking.

RAV roll-forward.

With regard to the treatment of fault costs, it is vital that companies are treated fairly and consistently. We remain concerned that to allow some companies to include fault costs in the RAV but not others, on the basis of some claimed misunderstanding at the time of the last price control review, risks incentivising DNOs to “game” the Regulatory Accounts. We believe that an equitable solution would be for all DNOs (for the purposes of rolling forward the RAV only), to retain the industry average proportion of fault costs within the RAV for the current price control period.

CHAPTER 7 – FINANCIAL ISSUES

The Cost of Capital

We will be responding separately and in more detail to the cost of capital paper published at the same time as the policy document. Overall, we are supportive of an after tax approach to the cost of capital with a separate ex ante allowance for the full tax costs each DNO would incur.

Ofgem have introduced a new definition of the post-tax cost of capital ("Vanilla") in the policy document. Our understanding however is that this is simply a modelling device to derive allowed revenues and it is difficult to assess whether that is an appropriate approach before we see the associated tax calculations.

In any event, it is clear that the relevant figure for assessing the price control proposals is the traditional "post-tax" WACC, which Ofgem indicate would fall in the range 4.2%-5%. We believe that this range significantly understates the cost of capital, particularly for efficient companies. In particular:

- Ofgem have based their range on the outputs of the CAPM model. However, the CAPM model is notoriously sensitive to the underlying assumptions. Indeed, the DNOs have already submitted alternative studies based on CAPM that suggest a significantly higher range;

- Similarly, we would recommend that more weight should be given to the Dividend Growth Model, which we calculate would produce a range for post-tax cost of capital in excess of 5%;

- Ofwat have produced a figure for the cost of capital of at least 5% post-tax. We do not understand how Ofgem can justify a range for the cost of capital that has a ceiling at the same level as the floor of the Ofwat range. We believe that the electricity industry is inherently more risky than water and hence a higher, not lower, range would be justified;

- Ofgem have not made any allowance for embedded debt or transaction costs. This implies that DNOs should leave themselves exposed to a debt maturity profile of no more than the current price control period or risk having interest payments above current rates "disallowed" (since Ofgem's calculation is based on an analysis of current market rates). We do not consider this to be either practical or desirable and we would therefore urge Ofgem to reflect industry average actual debt rates in the cost of capital;

- In terms of equity returns it is clear that continental utilities are earning significantly double-digit returns (circa 13-14%). Ofgem's range for equity returns is about half of that range. Clearly this will raise significant issues for DNOs in competing in the world-wide capital markets for funding; and

- Ofgem have not taken into account the significant step-change in investment over the next price control period by DNOs or the impact of this on cash flow.

We therefore believe that the range produced by Ofgem is insufficient to incentivise an efficient DNO to invest in its network. It is however clear that achieved returns include not just the base cost of capital but the scope for outperformance. It is the achievable level of returns that DNOs will ultimately focus on. As a consequence, we would urge Ofgem to consider the scope for outpeformance (net of possible liabilities under the quality of supply incentive mechanisms) in bringing forward initial proposals in June. As part of that, we believe that Ofgem should focus on the appropriate post-tax returns for the *efficient* companies being in the range 6% -7%, including around 100 basis points for outperformance.

Pensions Costs

Allocation between price controlled and non-price controlled activities

We accept Ofgem's proposals for allocating pensions deficits between price controlled and non-price controlled entities and, to that end, we would urge Ofgem to use the information we have already provided in assessing the relative split of staff.

Ofgem also consider the options for allocating assets: either in proportion to liabilities or a more detailed matching of the types of assets with particular liabilities. While the latter has some intellectual appeal, we are not convinced that the additional complexity (and cost) involved in carrying out this work would be justified since we think it would have limited impact on the final cost allowances.

Over or under provision

As noted in earlier responses, we believe that a retrospective adjustment for over or under provision would raise significant issues of regulatory risk, not least because previous price control settlements have not specified pension allowances and hence any assessment of allowances against actual contributions would necessarily be arbitrary. We also do not accept the statement that the available evidence would suggest a significant underspend relative to allowances. We therefore welcome the decision not to re-open previous price controls to assess over and under provision against previous "allowed" pension costs.

ERDCs

We remain firmly opposed to the proposed treatment of Enhanced Retirement Deficiency Costs (ERDCs). The summary of responses section of the paper in our view unfairly characterises the DNO position. In particular, we have never claimed in discussions with Ofgem that there was any agreement in past periods about the treatment of ERDCs. In fact, ERDCs were, to our knowledge, not discussed at the last price control, although it is inconceivable that Ofgem could argue that they were not aware of the practice, since, for example, it had been subject to a high profile Court case prior to the review.

There was thus no agreement about ERDCs at the last price review, which probably reflects the fact that pensions schemes were not in deficit at the time (i.e. the liability had not arisen and hence there was no reason for Ofgem and the companies to reach agreement on the issue). The relevant question is therefore if the pension deficits had been anticipated what would have happened at the last price control review?

We firmly believe that any such discussion at the last price review would have resulted in Ofgem setting an allowance in advance for the recovery of those costs. Otherwise, DNOs would, other things being equal, have earned a return lower than the cost of capital. It is also clear that customers have benefited from the cost reductions that gave rise to the ERDCs. Accordingly, we do not consider that a negative adjustment for ERDCs is justified.

We would be particularly opposed to any adjustment in respect of periods prior to the present price control period (i.e. before 2000) for all of the reasons set out in our previous response. The effective re-opening of the 1995 price control and the privatisation settlement, in our view, would significantly increase investors' perceptions of regulatory risk going forward.

COMMENTS ON OFGEM'S APPENDIX 1: CALCULATING THE CAPEX AND OPEX ROLLING ADJUSTMENTS

Opex roller

We are disappointed that Ofgem have not responded to our comments made in response to the December Consultation Paper. In summary, these were as follows.

- We continue to believe that stronger incentives will be provided if the opex roller is formulated as part of the price control formula to reward out-perform once on an annual basis rather than DNOs having to wait until the 2010 price control review.

- We have advocated above the use of "Average Costs" for setting allowed opex. It is still clear to us that any move away from average costs, for example towards frontier costs, risks significantly weakening the incentives/rewards for frontier companies. This arises because there will always be a residual incentive to delay cost savings just ahead of the price control if future allowances depend on one's own outturn cost. We do not believe that the opex roller resolves that issue, particularly since most of the reward from the opex roller will not materialise until 2010 and is therefore subject to regulatory risk.

- We note that OFWAT in their recently published paper are still advocating the use of a multiplier to reward the frontier companies and we support this.

- Exceptional items are unlikely to be the same each year, but in most years there will be some exceptional items and these may negate any benefit from the opex roller. Indeed, by not excluding exceptional items, DNOs could be incentivised to 'game' the regulatory accounts in order to benefit from the opex roller and this would be undesirable. We therefore believe that exceptional items should be removed for the purposes of calculating the opex roller, to capture the movement in underlying efficiency.

- We are opposed in principle to any eligibility test. If such a test is to be applied, then it must be defined now such that DNOs can judge the potential for out-performance against any potential disallowances. Otherwise it will undermine the intended effect of the opex roller.

Capex roller

Ofgem's simplified methodology appears to arrive at the same answer as the DNOs' proposed methodology (if with the loss of some transparency) therefore we have no further comments.

COMMENTS ON OFGEMS Appendix 3 : DEVELOPING A RIA FOR METERING

<u>Objective</u>

Ofgem's objectives are stated as "to secure effective competition in the provision of metering services, and to remove unnecessary regulation as competition develops".

While we fully support the second objective, we believe that Ofgem have never made a case for the huge complexities introduced into the supply market in pursuit of the first objective. Indeed, we continue to believe that metering competition has introduced significant additional cost into the transfer process, is inhibiting the development of new technologies and may be used by some suppliers to undermine supply competition.

Options

These points not withstanding, it is clear that the fundamental systems and process are in place to allow competition in metering services, both MAP and MOP. There are therefore no barriers to entry and accordingly we believe that price controls could be removed now. We are concerned that the Competitive Market Review, in the way that it is backward looking, will not reflect the fact that the pressure to facilitate competition are now present and there is therefore already downward pressure on prices from this competitive threat (whether or not individual suppliers switch meter provider).

We have provided comments on the form of any residual price control above.

We would also support removal of the licence obligation. The new entrants to the metering services market operate unlicensed and are not subject to price controls. We are therefore concerned that price controls will distort competition, particularly since some meter operators enjoy similar market shares to DNOs, but will not be directly regulated.

Risk and unintended consequences

We believe that Ofgem's current proposed approach to metering price controls will result in stranded assets for DNOs as market share is lost. These assets and costs were incurred as part of a licence obligation (i.e. DNOs could not refuse or, in the extreme, withdraw from the metering market). To suggest that "winning business out of area will mitigate these risks" is unacceptable. The only acceptable solution is full protection through the distribution price control. We would therefore expect the final RIA to more fully address the issue of stranded assets.

Competition

We simply do not accept that "a binding price control will directly influence the pricing of the dominant incumbents in the market for metering services". In several areas, and growing, the DNO is not the dominant incumbent and has in effect potentially been replaced by an unregulated monopoly.

COMMENTS ON OFGEM'S APPENDIX 4 : DEVELOPING A RIA FOR QUALITY OF SERVICE

We have responded in detail above to Chapter 4 – Quality of Supply. We have therefore restricted our comments here to our key points relating to developing a RIA for quality of service.

The costs and benefits associated with improving quality of service have been clearly set out in DNOs' Forecast Business Plan Questionnaires (Base Case, Ofgem Quality of Supply Case, and DNO case). However, we still do not regard the Quality of Supply cases as of any value. They are based on Ofgem assumptions and sensitivities which do not take into account what customers expect, or are willing to pay for. We are concerned that Ofgem believe they can simply use the quality of supply scenarios to "flex" the base case. This is not the case and we continue to advocate the DNO case as the correct starting point.

A major concern is that DNOs have had their exposure to financial penalties and risks increased significantly through, for example, Guaranteed Standards, IIP and the Interim Arrangements for storm compensation. In the absence to date of any increased reward to compensate for this additional risk, we continue to propose that all these exposures should be capped in aggregate within the 2% p.a. cap currently in place under IIP. We would expect the final RIA for quality of supply to address the question of DNO exposure to penalties under the various quality of supply schemes and the resultant impact on the cost of capital.

We believe that the telephone survey is bureaucratic, costly, serves little purpose and should therefore be discontinued. In addition, we continue to believe that the Data Protection requirement to inform customers that their call may be recorded for the purpose of the survey acts against good customer service (particularly in emergency situations). It is clear that performance of all DNOs is converging and to a level which is superior to other industries and other countries. Against this background, we would expect the final RIA to carefully assess the costs and benefits of the telephone survey.

Appendix 1-Setting Incentives to Maximise Efficiency

Introduction

1. The Distribution Price Control consultation paper published in March highlighted Ofgem's three main concerns in setting allowances in respect of operating costs and capital expenditure:

   (i) Between reviews DNOs have a strong incentive to re-categorise costs from opex to capex, since the company would retain 100% of savings in the former, but a much lower percentage of the latter. Ofgem seem concerned about their ability to make adjustments at the price review for any inappropriate behaviour arising from this perceived mis-match in incentives;

   (ii) There may be inappropriate incentives to defer major capital expenditure projects under an RPI-X framework since the company would retain the benefit of the "allowed" expenditure during the price control period and re-submit a claim for the same expenditure at the next price control review; and

   (iii) There is in any event a wider incentive to "talk-up" capex programmes at the price review to provide scope for future savings.

2. Given information asymmetry, it is suggested that these issues might justify a change in the fundamental basis of RPI-X regulation by weakening the existing incentives to reduce costs. In particular, it is suggested that a much larger proportion of operating costs (including fault costs and potentially all repairs and maintenance costs) could be capitalised. In addition, the benefit retained by the company for not spending the capex allowance could simultaneously be reduced (by only allowing the implied return to be retained, not the depreciation).

3. We believe that Ofgem's proposals represent a radical departure from RPI-X regulation towards a rate-based methodology, with all of the attendant problems with that approach. This paper therefore sets out why we believe that the combined effect of this new approach would be detrimental to incentives to reduce costs and therefore would act against the interests of customers. We then propose an alternative framework that would proportionately address the issues facing Ofgem in the present price review, while maintaining incentives to maximise operational efficiency.

4. It should be noted from the outset that a major re-allocation of opex to capex would also raise issues about financing and cashflow of DNOs. For example, we consider that the depreciation profile necessary to achieve cash neutrality following the cost re-allocation would raise significant issues about inter-generational funding of investment and the value of distribution businesses. In addition, Ofgem's proposal would represent a fundamental shift in the regulatory paradigm that has not been flagged-up as necessary until late in the price process and indeed was not highlighted at all during the yearlong review of network company incentives that preceded the distribution price review. Hitherto, Ofgem have (to their credit) worked hard to preserve the stability of the price control

framework in particular by preserving the integrity of the RAV. Against this background, we firmly believe that Ofgem's proposed re-allocation of costs into capital would raise significant concerns about regulatory risk going forward. These issues are important and cannot be ignored, but are not discussed further in this paper.

The Effect of Ofgem's Proposals on Incentives

5. The effect of Ofgem's proposed incentive scheme on DNO behaviour can probably best be illustrated by considering a specific example. Taking a "typical" DNO, the following assumptions have been made:

- Operating costs are £100m p.a., of which £25m is non-controllable (e.g. rates). Of the £75m remainder, £50m is fault costs and repairs and maintenance;
- Annual capex is £100m;
- The cost of capital is 6.5% pre-tax (ignore the fact that this is not compatible with investment of £100m!); and
- A 20-year depreciation cycle.

6. The table below shows the benefit to the DNO of reducing controllable costs (i.e. both capex and opex) by 10%.

Table 1: Benefits From 10% Cost Savings

£m	**Current**		**Proposed**	
	Saving	Reward	Saving	Reward
Opex	75		25	
Pass through of	7.5	7.5	2.5	2.5
Capex	100		150	
Return @ 6.5%	10	0.7	15	1.0
Depreciation @5%	10	0.5	-	-
Total benefit (pre-tax)		8.7		3.5
Total benefit (post-tax)		5.6		2.3

7. Two points are apparent. First, it is clear that Ofgem's approach would more than half the value of the incentives, since the benefit to the company of cost reductions would be £2.3m (post-tax) compared to £5.6m under the current incentive framework. Second, it is also clear that the main driver of the reduction in value would arise from the transfer of substantial costs from opex to capex, rather than removing the depreciation benefit from capex savings.

8. The position on incentives is however even worse than indicated in the table for a number of reasons. First, for simplicity we have ignored the impact of discounting which would tend to further reduce the benefit to the company of reducing costs.

9. More fundamentally, this analysis ignores any regulatory "ratchet" effect whereby the company takes into account the likely effect on future allowances of reducing costs in the current period. This effect is difficult to model and is present in any regulatory system where allowances are set for a fixed period based on an assessment of the company's own costs. It is however particularly prevalent in Ofgem's proposed rate of return model. Not only is the benefit of reducing costs lower than in the current approach, but Ofgem's model would further dampen incentives because future profits would also be reduced by the cost saving. Crudely, reducing costs in the current period would mean a lower RAV going forward, which means lower profits in future periods. This effect is tempered in part by the risk that the regulator at future reviews may disallow such "gold plating". However, as Ofgem note in the consultation paper, there are information asymmetries between regulators and companies and it is therefore apparent that regulatory scrutiny would not remove this issue altogether.

10. We also note that the prospect of "gold plating" and the evidence from the US utilities that such a problem exists, was the fundamental reason why the UK adopted RPI-X incentive regulation at privatisation. The present issues are not therefore new problems; they were considered in the original "Littlechild" report that formed the basis for applying RPI-X incentive regulation.

11. Another issue arises to the extent that any such saving would increase the exposure to penalties under the various quality of supply incentives put forward by Ofgem, including IIP, the guaranteed standards and storm compensation. Again, this is difficult to model. It is however clear that if the benefits to the company of reducing costs are small or marginal (£2m), but the costs of failure under the various service standards are high (£5m+ for IIP alone for a typical DNO), then the company will not risk making the savings. Ever-tighter quality of supply regulation will therefore compound any negative effect on incentives from Ofgem's proposal.

12. It is also important to note that the figures in the above table are *gross* benefits – they do not include the up-front investment costs that the company would have to pay in order to yield those savings. Again, these are difficult to model and would vary on a case-by-case basis. However, it is apparent that these costs exist. For example, in order to avoid industrial action it is normally necessary to reduce staffing levels by voluntary redundancy. The typical costs to DNOs of such redundancy are in the order of the annual salary, including pension costs.

13. Assuming that the up-front investment to achieve savings has a linear distribution, we have calculated for our assumed "typical" DNO, the "payback" required under different scenarios in order to meet the cost of making those cost reductions. This shows that under the present framework DNOs will only make a saving if the payback period is 18 months or less. Under Ofgem's new approach that would fall to six months. However, as noted above that is before discounting, taking into

account any regulatory “ratchet”, the reduced future profits from a lower RAV and any quality of supply penalties risks. Against this background, it is unlikely that DNOs would make any significant investments to reduce costs.

14. It is recognised that the above analysis is based on indicative numbers for a stylised DNO. However, the broad conclusion that Ofgem’s proposed approach would be detrimental to incentives are not dependent on the specific figures. Indeed, we have used an indicative 10% reduction in costs across the board just to keep the analysis simple. An alternative assumption of, say, 5% reduction in operating costs and 20% reduction in capex would produce the same outcome. Using the figures in table 1, the annual benefit to the DNO of such savings would be £3.9m (post-tax) under the current approach and £2.1m under Ofgem’s proposed approach (i.e. the incentive would be halved).

15. The analysis may be “rudimentary”, but is sufficient to demonstrate that Ofgem’s approach will seriously undermine the incentive framework that has persisted in the regulated industries for the past 15+ years.

16. This raises one final point. Putting the specific figures to one side, it is clear that Ofgem’s approach would reduce incentives to the extent that DNOs would need to assess very carefully the costs and benefits of making individual cost savings. At present, SSE has a reputation for cost reduction, which is based on many years of constantly striving to achieve greater efficiency. This is firmly embedded within the culture of SSE at all levels from the management down to front-line staff. It is clear that maintaining that culture and discipline would not be possible if the regulatory framework resulted in a need to more carefully assess, on a case by case basis, whether reducing costs was the correct strategy for the company. Ofgem’s economic fundamentalists would no doubt dismiss this point, but the fact remains that *in practical terms* one cannot manage a business to minimise costs if a mixed message is sent to staff about whether that is what we are trying to achieve.

An Alternative Approach - Opex

17. This dilemma does not arise in competitive markets. As a consequence, the strongest possible incentives would be provided by mechanisms that as far as possible mimic competitive outcomes. We have previously written to Ofgem about the use of an “average cost” methodology to setting operating cost allowances. Broadly, this would involve setting future allowances on the basis of the average DNO cost as indicated by the benchmarking exercise (the regression line). It is clear that this sends the strongest possible incentive to DNOs to reduce costs. In particular, there is no “ratchet” effect since a cost reduction by an individual DNO does not affect its future allowances. A paper setting this out in more detail is attached as annex A.

18. We would therefore urge Ofgem to set operating cost allowances on an average basis. This is relatively straightforward to achieve and would involve the following key steps.

(v) The DNO opex figures would first need to be adjusted for the 132kV network in Scotland, differences in capitalisation policies and regional adjustments (London and North of Scotland only, as per the last review). There would be no need for a detailed "normalisation" exercise which Ofgem are presently conducting and which is not shedding any greater clarity on differences in cost across companies despite months of work. For example, we calculate that Ofgem's analysis has only statistically explained an extra 3% of the difference in performance across DNOs despite taking £120m out of the combined cost base (which must presumably be added back at the end of the process).

(vi) Calculate a regression of operating costs plus total fault costs, using adjusted customer numbers, as at the last review. Given differing treatments of fault costs, we agree with Ofgem that this is the only credible (and statistically robust) basis for carrying out the relative efficiency assessment.

(vii) Future allowances would then be set on the basis of the average cost, with an assumed standard percentage capitalisation of the average fault costs (say 50%), less Ofgem's estimate of future efficiency. However, if an efficiency adjustment were made, DNOs would require a separate allowance for the estimated cost of achieving that efficiency (Ofgem would be taking the benefit of those savings up-front, so customers should pay the costs of making those savings "up-front"). It would also be necessary to make specific adjustments to recognise the cost increases facing all DNOs, particularly pensions.

(viii) To avoid any incentive to artificially capitalise future opex, Ofgem should make clear how the capitalisation policies are to be applied *going forward*. Ofgem's March paper seems to dismiss that this is possible. However, much has been achieved in the work on Regulatory Accounting Guidelines and we believe that work could go far in ensuring companies are applying similar policies and without involving detailed regulatory auditing by Ofgem. As an extra precaution Ofgem could ask all DNOs to confirm that their capex plans are consistent with the forward-looking capitalisation policy.

(ix) Separately, Ofgem would need to resolve the issue that some DNOs have raised over the *past* period in relation to the pkf adjustment. As we have noted in previous correspondence the key issue here is equitable treatment for all and in particular Ofgem need to ensure that certain DNOs are not rewarded for inappropriately "gaming" the system. A pragmatic solution would therefore be to apply the average fault capitalisation percentage retrospectively to all DNOs over the period from 2000-2005. This would have the attraction of producing the same outcome for customers since the industry RAV would be the same, although there would clearly be winners and losers amongst DNOs (some RAVs would be adjusted upwards, others downwards). The RAGs going forward (which were not in place in 2000) would avoid a similar issue arising in the 2010 review.

19. This approach would have a number of clear advantages:

- It would provide the strongest possible incentives to reduce costs and hence would produce lower bills for customers than Ofgem's suggested rate or return approach or the frontier methodology;
- It would be statistically robust (we calculate an R-squared of 80%+, which is higher than Ofgem have achieved in any previous review, to our knowledge);
- It would provide a common basis going forward for the treatment of costs categorisation and hence avoid some of the problems experienced in the current review; and
- It would allow Ofgem to focus on the key issues, rather than being diverted by detailed "normalisation" assessments which, in our view, have failed to produce meaningful results in every price control to date.

20. We have just received Ofgem's letter about initial views on setting operating cost allowances and capex. We are still assessing the detail of Ofgem's approach, but it is clear that it is broadly consistent with the above framework. For example, Ofgem have adopted an approach based on controllable opex plus total fault costs. In addition, depending on the detailed approach adopted the quartile scenario may have similar incentive properties as average costs (i.e. if it clearly recognises that the efficient companies would enjoy higher returns than the laggards). The Ofgem "initial views" approach could therefore form a sound basis for adopting the approach set out above.

An Alternative Approach – Capex

21. The above approach would not however resolve Ofgem's concerns about the incentives in respect of capex and in particular the large capex programmes put forward by some companies.

22. We believe that these issues can be resolved by setting company specific allowances for capex, based on the DNO case (we would not support Ofgem's quality of supply case, since the disaggregation work which underpins those "targets" is not robust). It would need to be clear that a fixed percentage of fault costs would be capitalised for all DNOs (consistent with the assumption in setting opex) and DNOs should be asked to confirm that capex forecasts are consistent with that basis.

23. In setting those allowances, Ofgem would have regard to its consultant's reports. It would also need to assess the DNO case against forecast improvements in customer service (CML and CI) and resilience, although it should be accepted that it will never to possible to mathematically link allowances with quality of supply outputs.

24. Ofgem seemed to be particularly concerned about deferral of major capex projects. Ofgem recognise that in certain circumstances deferral is efficient and we would agree. We would also however agree with Ofgem that some further protection might be required in the case of significant deferrals. In particular, we believe that it is reasonable that if a large scheme has been deferred during the previous price control period, but forms part of the DNOs plans for the current period, then that scheme should only be included in the capex allowance with "strings attached". That is, it would be reasonable for

Ofgem to only include an allowance in regard of a previously deferred scheme on the understanding that if the scheme is deferred in the 2005-2010 period, the full benefits of that deferral will be retrospectively returned to customers at the 2010 review. Such an approach would significantly limit the scope for "gaming" capex deferrals, since we believe that the risk to Ofgem from deferral stems mainly from larger schemes or programmes (rather than more routine maintenance programmes where the prospect of deferral is more limited). For the avoidance of doubt, we are not proposing a detailed "list" of all capex projects which would be agreed with Ofgem at the time of setting the price control. We agree with Ofgem that such an approach would be onerous. It should however be possible to apply this treatment to specific, major projects (and we would not expect more than one or two per DNO, if any) that have been subject to deferral in the past but are included in the future plan.

25. Against this background, the risk of inappropriate "gaming" of capex forecasts would be mitigated through a combination of:

- Due diligence by Ofgem and their consultants (and indeed other DNOs);
- A clear understanding of capitalisation policies going forward; and
- The quality of supply incentives put in place by Ofgem, including IIP rewards.

26. However, this could be supplemented by a sliding scale treatment of capex underspends. This could work as follows:

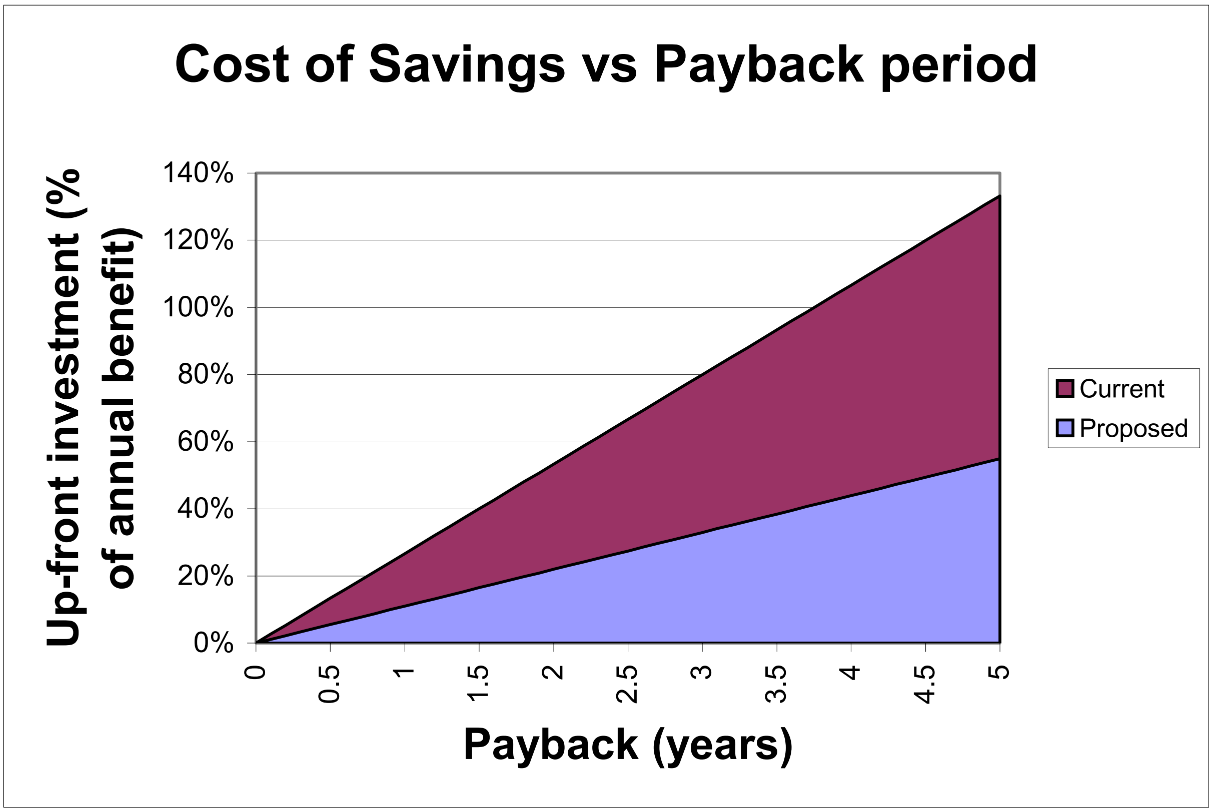
(i) For underspend of less than 10% of the allowed capex, the DNO would retain both the allowed return and depreciation and to avoid the periodicity problem this would be retained for five years according to the new "capex roller" incentive.
(ii) If the underspend is greater than this, there may be a suspicion that the DNO has "gamed" its capex. Accordingly, a lower level of retention may be appropriate in these circumstances. For example, for underspend of between, say, 10-20% the DNO may lose the benefit of the depreciation element of the allowed capex, as Ofgem propose.
(iii) For underspends greater than this, there would be full clawback. Indeed, it could be possible to introduce a penalty regime for significant underspends (e.g. >30% underspend against allowance). That is, for significant underspends it may be appropriate to penalise the DNO for poor forecasting.

27. The specific parameters are a matter for debate and indeed there may be a case for tighter "triggers" to more positively discourage significant capex underspends. For example, the parameters could be set at 95% spend (keep return, keep deprecation), 90-95% (keep just depreciation); and 80-90% (return all of the benefit to customers). In these circumstances, the punishment for underspends below 80% could be set on a sufficiently material basis to ensure that any benefit from *all* of the underspend is quickly eroded. Thus, it could be possible to design a mechanism that means that any DNO that underspends by more than, say, 20% would be put in the same position as if the entire amount of that capex (i.e. all of the underspend) had not been allowed in the asset base at all. However, it may be more difficult to convince all DNOs that this more aggressive approach is justified.

28. Putting the specific parameters aside, a sliding scale mechanism also has the attraction that it could be applied on a similar basis to overspends of capex over and above the allowance when the price control was set (which Ofgem also acknowledge as an issue that needs to be addressed).

29. The above mechanism would clearly maintain incentives for efficiency, without exposing Ofgem to the risk of increased out-performance in light of exaggerated increases in capex forecasts. However, one criticism of the above approach might be that there would still be an incentive for all DNOs to slightly "talk-up" capex plans to take advantage of the 10% allowance.

30. It is apparent that this risk would exist, but it is vital that Ofgem's response to that risk is proportionate to the problem. In particular, for a DNO with an annual capex of £100m, the "cost" to customers of "gaming" would be around £1m per year (6.5% return plus 5% depreciation on 10% saving of £100m), even assuming Ofgem's consultants fail to spot any inappropriate forecasting. This can be contrasted with the profound effect on incentives of Ofgem's proposed "rate-based" approach.



31. For example, taking the example highlighted in table 1 above and assuming that the investment cost of making savings is evenly distributed, we calculate that only 40% of efficiency projects would be cost-effective under Ofgem's

proposed approach. This would result in a net loss in efficiency savings to customers of £10m. Put another way, Ofgem's approach would reduce the optimum payback period before it becomes economic to invest in efficiency savings from 18 months to around six months. As a consequence, the DNO would in Ofgem's framework not make any efficiency savings where the cost of making those savings is more than 50% of the annual saving. Using the figures from our "typical" DNO this would cost customers £10m per annum. This lost efficiency is illustrated in the graph above.

32. Against this background, it is apparent that moving towards a rate-based approach to regulating the DNOs would lead to higher bills to customers. Put simply, the savings from stronger incentives to reduce costs and the lack of "gold-plating" would more than offset any inappropriate gains to DNOs arising from information asymmetry. This fundamental conclusion is not revolutionary – it was the very reason the UK adopted RPI-X regulation over the old US-style rate-based approach and these advantages remain as relevant today as at privatisation.

Conclusion

33. We do not believe that Ofgem have adequately demonstrated that the issues raised by the DNOs' present business plans provide sufficient justification for the substantial weakening of incentives that would arise under Ofgem's proposed approach. At the very least, we would expect a detailed regulatory impact assessment for such a major departure from the principles of RPI-X regulation.

34. Ofgem has provided no such analysis, but we have sought in this paper to demonstrate the practical impact of Ofgem's proposals on incentives to reduce costs. In particular, the weaker incentives would lead to higher bills for customers over the longer term than the present approach.

35. However, we have also suggested additional mechanisms, which could be adopted by Ofgem to mitigate the perceived problems of RPI-X regulation. In particular, we believe that a sliding scale mechanism which gradually reduced the benefit from capex savings coupled with the application of some broad rules of thumb on operating cost allocations would maintain incentives and simultaneously protect Ofgem/customers from "gaming". It is recognised that there is still a residual risk of excessive forecasting of capex at the margin, but this risk must be assessed within the context of the incentive framework overall. In any event, we have demonstrated above that the RPI-X incentives framework will still produce lower bills for customers than Ofgem's suggested "rate-based" approach to setting future cost allowances. We would therefore urge Ofgem to adopt the approach set out in this paper to setting future opex and capex allowances.

Annex A: The Incentive Properties of the "Average Costs" Methodology

Introduction

1. In determining the revenue each company needs to cover its operating costs, Ofgem will need to consider two questions:

- How quickly should efficiency savings be passed on to customers? and

- How should companies be incentivised to continue to seek out efficiency savings, especially when those savings are becoming harder to find?

2. As Ofgem have recognised in the work on incentives, these questions are linked and (potentially) conflicting. It is also apparent that these issues do not arise in a competitive market.

3. In DPCR3 Ofgem introduced the "frontier" costs approach to assessing operating cost efficiency and projecting future costs. This paper argues that this approach has significantly weaker incentive properties than the "average" cost methodology used in previous price control reviews, and which better mimics a competitive market.

Background

4. The "frontier" costs methodology was introduced on the premise that companies had to be allowed their own costs at the start of the price control period, and that companies not on the frontier should be allowed a catch-up period ("glidepath"). These companies were allowed four years to catch up 75% of the way to the frontier. Presumably the 25% discretion was to allow for perceived uncertainties and inaccuracies in the estimation of the frontier.

5. The frontier was not expected to improve over the price control period, but remained at the 97/98 level of base costs for the frontier companies. However, it can be argued that this represented no reward comparatively for the efficient companies in recognition of their frontier status and hence did not provide any incentive for those companies to further strive to improve efficiency during the next price control period. The glidepath that was introduced for the "laggards" provided a generous grace period before those companies were required to achieve frontier performance. In effect, therefore, the glidepath approach provided the inefficient companies with the opportunity to gain benefits from efficiency savings that were not available to the frontier companies that had already achieved those savings. This produced a further disincentive to efficient companies to continue to drive the frontier forward.

6. Ofgem made a token recognition of frontier performance by allowing at a late stage in the review an arbitrary 1% additional allowed revenue to the three companies on or near the frontier, for the duration of the price control. Not only was this not symmetric with the benefits available to the laggards but such "within range" adjustments are not consistent with Ofgem's declared aims of transparency and predictability of regulation.

7. It is noted that the importance of rewarding the frontier companies has been recognised by OFWAT in the current price control review in the water industry. This is particularly important, since it is the performance of those companies that determines the price control outcome for the whole industry and hence all customers.

8. Ofgem have since committed to an additional fixed retention period for opex savings made after 1 April 2003, ostensibly to solve a perceived periodicity problem. However, it can be argued that this mechanism alone will not completely resolve the periodicity problem. In particular, as long as a company's allowed future costs are dependent on past performance there will always be a residual incentive to consider the effect on future allowances of delaying individual efficiency improvements.

9. Ofgem also assert in the July consultation paper that the application of fixed retention periods on their own will not weaken incentives on companies that are at the frontier. As noted above, the glidepath adopted at the last price review rewarded inefficient companies by providing them with additional revenue for failing to achieve the standard of the frontier companies. The fixed retention period works in the same way as the glidepath and there is a real danger that it will further reward those companies in contrast with the frontier companies.

10. This arises because there is significantly more scope for the inefficient companies to reduce costs compared to companies that were at the frontier at the last price control review. Indeed, as noted above, the frontier approach at the last price control review only required those companies to achieve three quarters of the difference in cost with the frontier companies over the price control period. There is thus a greater prospect for additional returns for less efficient companies under the fixed retention period than for companies that have made identical savings earlier in the regulatory cycle. As above, this reinforces the poor incentive framework for frontier companies.

11. However, the fixed retention period for operating cost savings is welcome, particularly given the fact that the marginal investment necessary to achieve future savings is likely to be much greater than in the past. This paper argues that this cannot be combined with a frontier costs approach but that this methodology should be supplemented by an average cost approach to setting future operating costs allowances. Otherwise, elements of the periodicity problem will remain and incentives on the frontier companies will be weakened further.

<u>The "Average" Costs Methodology</u>

12. The benefits of competition depend on reward for winning and penalty for losing. Those companies that are efficient survive, those that are not make low returns and have their management replaced. This creates an ongoing pressure to maximise efficiency.

13. Under competition, prices are set by the market and individual firm's costs have a negligible impact. A drop in prices only occurs if all companies reduce their costs. A firm will always be better off than it would be without the cost reduction and will keep the benefits until its rivals catch up. This can be contrasted with the frontier costs regulatory approach, whereby if a company performs well it receives a tougher target (i.e. the "ratchet" effect).

14. Under the average costs methodology, a company's allowed costs are based on the industry average for a firm of their size (this has been arrived at in the past by regression analysis, although there is no reason why other suggested statistical techniques should not be used to find the average as well as the frontier). This better replicates how a competitive market works, by relating operating cost allowances to factors that are, as far as possible, exogenous to the individual company's past performance.

15. Under this approach, since no individual company could be expected to materially affect the industry-wide regression line (i.e. the average), there is no incentive to delay efficiencies. An average cost approach would thus resolve the periodicity problem and the regulator would no longer have to worry about the speed of transfer of efficiency savings to customers. It would also mimic the outcome of competitive markets where companies with lower than average costs receive higher returns and vice versa. Such an approach would therefore provide the strongest possible incentive on all companies to reduce operating costs.

16. Basing allowed costs on the industry average would also be consistent with an industry cost of capital (i.e. set for the average company). An inefficient company would earn a return less than the cost of capital for as long as they under-performed the average.

17. In aggregate the use of average costs produces the same allowed cost for the industry as the total of companies actual costs, with the added benefits that customers pay the same whether served by an efficient company or an inefficient company. An average cost approach would also avoid benchmarking against the frontier, which was heavily criticised at DPCR3.

18. The rolling opex incentive "bolted on" to the average cost methodology would then provide a catch-up mechanism and link back to companies' actual costs at the start of the period, replacing the glidepath.

19. The benefits of the average costs approach were also recognised by Ofgem's consultants Frontier Economics. In their report they point out that companies will eventually reveal the efficient level of costs through the level of profits made. However, assuming that companies have differing levels of efficiency, they argue that benchmarking provides additional information about how far costs can fall and therefore allows earlier price reductions. If benchmarking is based on the average, then as we have also argued above, a company should not be worried about reducing costs and benchmarking because the change in its own costs does not affect the average.

20. To illustrate this, Frontier calculate that under a five year fixed retention mechanism a company keeps 29% of its opex efficiency savings. The proportion retained increases as the number of firms increases, for example with 14 companies the retention is 29% + (71%*13/14) = 95%, because under an average costs methodology a company's own cost reduction is weighted by 1/14 when calculating the industry cost reduction.

21. The attraction is that all firms face this same high incentive, however the incentive power has increased without reducing customer benefits. For example, if they all make the same cost reductions then each firm's price falls at the price control review by the full amount of the cost reduction, and customers receive the full 71% of the benefit.

Conclusion

22. We have discussed above the strong incentive properties of an average cost approach to setting operating cost allowances, which in our view should be used to supplement the five-year retention period. There is a real danger that alternative approaches, including a repeat of the frontier methodology adopted at the last price review, will significantly blunt incentives for the efficient companies to constantly strive to reduce operating costs. We would therefore urge Ofgem to commit to the use of an average cost approach at the earliest opportunity, with subsequent discussions about the detailed approach to setting the average line following the work by Cambridge Economics.