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Dear Cemil

Electricity Distribution Price Control Review – Initial Consultation.

You have invited views on the above document and I am pleased to attach our response.

Overall, we welcome the setting out of the objectives of the price control review and our main comments are set out below.

- We welcome Ofgem's work to develop the price control framework to ensure that DNOs retain appropriate incentives with respect to the connection of DG. SSE's main concern, in relation to distribution investment to support DG, is to establish with certainty that Capex will be remunerated by earning a return on the RAV at least equal to the cost of capital. Within the context of the hybrid mechanism put forward by Ofgem, we believe that this means that the pass-through element should cover all of the system reinforcement cost, which could be supplemented by a 10-year £/MWh term to reflect the additional cost and risks of accommodating greater volumes of DG.

- We continue to support the use of benchmarking and regression analysis to assess relative efficiency. However, we remain opposed to the use of statistical techniques that rely on benchmarking total costs, and we therefore agree with Ofgem's assessment of the potential problems with this approach. In particular, we are not convinced that it is possible to effectively benchmark capital expenditure between network companies.

- We are concerned that Ofgem's proposed framework for setting projected future costs will weaken incentives for frontier companies and will not fully resolve the periodicity problem. We note that the importance of rewarding frontier companies has been recognised by OFWAT in the current price control review in the water industry. We would urge Ofgem to similarly recognise the importance of incentives for frontier companies and we believe that this could best be achieved by adopting an "average cost" approach to setting future operating cost allowances.

- We believe that Ofgem should set out a commitment to extend accelerated (twenty year) depreciation to all DNOs when the vesting assets are fully depreciated, as was the case for some companies at the last distribution review.

- We believe that the cost of capital should be calculated on a post-tax basis, with an ex-ante, company specific allowance for tax which takes into account the anticipated incremental increase in tax liabilities following recent changes in capital allowances.

- We welcome the recognition that pensions are a legitimate cost to be recovered through the price control but we have some serious concerns about Ofgem's views on enhanced pension entitlements and the treatment of non-distribution staff. We believe that in both of these areas Ofgem have failed to fully take into account the obligations placed on network companies under the industry pensions scheme.

- We see no reason why merger savings should be treated any differently to any other form of efficiency saving. For all merged companies, provided they have achieved a minimum of £12.5m (the target set at the last distribution review) efficiency savings across the merged companies, then no further merger savings should be required.

- Ofgem appear minded to split the metering price control from the distribution price control. We still do not believe that this is necessary and are disappointed that Ofgem have rejected the DNOs' proposal to retain the existing distribution price control for meters.

- We would be opposed to significant additional obligations on DNOs with respect to performance standards, although we would support a new standard in respect of network resilience. We firmly believe that any financial incentive under the standards should be symmetrical and should provide the prospect of a potential financial benefit equal in size to the maximum financial penalty under the scheme.

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

Electricity Distribution Price Control Review – Initial consultation

Response by Scottish and Southern Energy plc

Background To The Review.

We support the broad objectives for the distribution price control review as set out in paragraph 1.9 of the document. We also welcome the commitment from Ofgem to resolve key policy issues at an early stage in the review to provide DNOs with greater certainty earlier in the process.

This is particularly important since there are a substantial number of new areas of uncertainty for DNOs compared to previous price reviews. The specific areas where we would welcome early clarification of Ofgem's policy include:

(i) Distributed generation: We would welcome further details on the proposed incentive term in relation to investment to accommodate distributed generation.

(ii) Depreciation: We believe that Ofgem should set out a commitment to extend accelerated (twenty year) depreciation to all DNOs when the vesting assets are fully depreciated, as was the case for some companies at the last distribution review.

(iii) Tax and the Cost of Capital: We believe that the cost of capital should be calculated on a post-tax basis, with an ex-ante, company specific allowance for tax which takes into account the anticipated incremental increase in tax liabilities following recent changes in capital allowances.

(iv) Metering Costs: We continue to believe that existing meters on circuit should not be removed from the RAV to protect DNOs from the risk of stranded assets. These investments were made in pursuit of a regulated obligation and we therefore believe that removal from the RAV would raise significant issues of regulatory risk.

(v) Pensions: We welcome the recognition that pensions are a legitimate cost to be recovered through the price control but we have some serious concerns about Ofgem's views on enhanced pension entitlements and the treatment of non-distribution staff. We believe that in both of these areas Ofgem have failed to fully take into account the obligations placed on network companies under the industry pensions scheme.

Each of these areas involve "high level" policy decisions which will not be affected by the information provided as part of the business planning process. We therefore see no reason why Ofgem can not provide its conclusions on each of these policy areas in the next round of consultation for the price control review.

More generally, we are concerned that there remain a large number of issues for consideration, against the background of a very tight timetable for the review. We believe that this further supports early resolution of as many policy issues as possible if the overall project plan is to be achieved.

Form, Structure and Scope of The Price Controls.

We agree with Ofgem that the broad structure for the price control remains appropriate. We also agree that five years remains, on balance, an appropriate duration.

Revenue Drivers

The 50/50 units distributed/projected customers revenue driver was intended to provide DNOs with protection against increasing costs due to load growth, but to avoid introducing an incentive to seek out new load which may be inconsistent with energy efficiency/environmental aims. The document makes no mention of tariff baskets, but these were also retained for a similar reason (i.e. to reflect the costs of changes to the mix of units distributed).

We see no justification at this time to change these drivers. However, there seems no particular logic to or benefit from the use of projected customers rather than actual customers within the price control formula.

The Scope of the Price Controls

EHV charges have hitherto been excluded from the price control because they tend to be calculated on a site-specific basis and hence it is not really practicable to incorporate EHV charges within the price control. Furthermore, such customers are protected by the right to request Ofgem to determine charges in the case of a dispute with the DNO. We believe that these considerations still apply.

In addition, in line with Ofgem's guidance and the last price review, we have set our EHV charges over the current price control period to be consistent with the assumptions underlying the price control. As a consequence, our EHV customers have seen real reductions in prices over the current price control period.

We therefore believe that EHV charges should continue to be an excluded service.

We also agree that top-up and standby charges, non-trading rechargeables and the other minor activities listed in the document should remain as excluded services.

Although this Initial Consultation does not refer to the metering price control, Ofgem appear minded to split the metering price control from the distribution price control. We still do not believe that this is necessary and are disappointed that Ofgem have rejected the DNO proposal, despite recognising DNOs' concerns about the risk of stranded assets. The key issue for us is the value of metering assets that Ofgem propose to transfer out of the RAV.

We are strongly of the view that there should be no transfer of metering assets out of the distribution RAV because these assets were installed in compliance with a regulatory obligation. It is therefore unreasonable to expose DNOs to the risk of stranded assets. For these reasons, we cannot support splitting the metering price control. We have commented on this issue in more detail in our response to the consultation on metering issues.

Competition in Connections

We see no reason for any form of regulation to apply to the contestable element of connections. This is a competitive activity with many connections providers active in the market. Furthermore, it is well documented that it is very difficult to set price controls in competitive markets, without introducing distortions into the market. Given the variability in size and type of connection, it would be particularly difficult to price control contestable connections. In our view, it would also be an odd decision to introduce new price controls to parts of the business that have not been subject to such controls since Privatisation at the very moment that competition is developing.

DNOs have a licence obligation to provide a connection on request ("connector of last resort"). As a consequence, the non-contestable element of connections clearly has to remain part of the licensed distribution business. However, we do not believe that it is necessary or practicable to bring this within the price control.

As with EHV charges, connections activity was originally treated as an excluded service because the volume and type of connections vary considerably, and this situation has not changed. It should also be remembered that DNOs already have to publish charging statements and provide connections on a reasonable and non-discriminatory basis. Customers are further protected by the right to request a determination of charges from Ofgem in the event of a dispute. By contrast, a price control would introduce significant new risks and uncertainties for customers and DNOs. We therefore believe that the non-contestable element of connections should remain as an excluded service.

We also believe that the price control review should address the following additional points in respect of connections:

- As Ofgem are aware, live jointing will bring significant additional liabilities to DNOs. Companies must therefore be compensated through the price control for taking on board these additional risks;

- The licence obligation applies to the contestable as well as the non-contestable elements of a connection. This means that companies cannot withdraw from the market, even if losing market share, and have to maintain the capability to meet this obligation. They must be allowed to recover these costs through the price control;

- By leaving connections within the distribution business, DNOs will maintain control of the resources for example to utilise in severe weather disruption. It is vital that this flexibility is maintained; and

- If the contestable element of connections was to remain regulated (i.e. as an excluded service), then the "reasonableness" test applied in Ofgem determinations should only apply where a customer was not able to obtain an alternative quote. In our view, it would be inappropriate for customers to use the Ofgem determination process as, in effect, an alternative tender.

Fixed Retention Periods For Efficiency Savings

We support the commitment to a fixed retention period for both capex and opex savings made after 1 April 2003 and have commented more fully on this in our response to the section on assessing costs. We also agree with Ofgem's proposal that efficient non-operational capex should be included in the RAV.

In relation to the inclusion of capex savings in the rolling RAV, Ofgem state that they intend to "take a more general view [rather than a mechanistic link to the 2004/05 targets] of whether companies have met their quality obligations". One reason for this is stated as "the 2004/05 targets are now recognised not to be equally challenging across all DNOs". We would strongly disagree with this assertion, particularly since the work on disaggregation is not yet complete. We are also concerned at the suggestion that new tests of efficiency may be applied to whether capex efficiencies are to be included within the new incentive term. We do not believe that this is consistent with Ofgem's declared aims for the price controls to be predictable and transparent. We would therefore urge Ofgem to provide further clarity on this issue.

Improving the Incentive and Price Control Framework

The document states in relation to the rolling retention periods for efficiency savings that "there does not appear to be a strong reason at present to move away from a five year retention period". However, Ofgem have not put forward any analysis to support the existing five year period, other than a general observation that costs overall have fallen.

The length of the retention period is not actually the main issue here. The question that needs to be addressed is the optimal sharing of efficiency savings between customers and shareholders. This can then be adjusted either by varying the retention period or by varying the proportion of the saving retained. Ofgem have now received from the DNOs a paper on this subject, arguing convincingly that the benefit to customers from cost saving initiatives is maximised if the share retained by the DNO is at least a half. As the easier initiatives are accomplished, the proportion needs to rise to at least two thirds. It can then be shown quite simply that retention periods considerably in excess of five years are required to deliver a 50/50 share.

We are pleased to note that Ofgem intend that companies that are best performers will be provided with incentives to remain at the frontier. We are supportive of the general regression methodology for assessing relative efficiency adopted at the last distribution price review but do not believe that the "frontier" costs approach to projecting future costs used at that review was an improvement on the "average" cost methodology used previously. We comment on this more fully in our response to the section on assessing costs.

Quality of Service and Other Outputs.

The Scope of the Output Measures

We agree that it will be appropriate to consider the package of output and performance measures that DNOs will be required to comply with as part of the price control review. In particular, it will be important to ensure that the package of proposals within the price control is consistent and that sufficient revenue is allowed to fully cover the costs of the various obligations imposed on DNOs. As part of that, it will also be necessary to consider the level of risk that DNOs are exposed to under the various incentive schemes and the implications of that level of risk for the cost of capital.

We are also concerned that Ofgem seem to be minded to consider a range of additional obligations on DNOs with respect to performance standards, many of which would be subject to financial incentives. We are already concerned that the existing incentive structure encompassing the IIP and GOSPs is becoming increasingly complex and expensive to administer. We also firmly believe that any financial incentives will need to be symmetrical and hence include the possibility of a reward of equivalent size to the maximum possible penalty.

Against that background, we do not see any justification for the additional output measures suggested (i.e. SF6 emissions, amenity issues and water pollution due to leakage from oil filled cables). In addition, we believe that there would be significant measurement issues with any such incentives, which at the very least would be complex to administer. We do not believe that it would be acceptable for DNOs to be exposed to penalties (even if balanced by some reward/upside scheme), when DNOs would be exposed to the vagaries of measurement. In our view, the only way to tackle this kind of issue is in a similar way to the replacement of cast-iron gas mains by Transco (i.e. a policy decision to change all such assets over time with the corresponding investment recognised in investment plans).

We do, however, support the introduction of additional outputs and incentives regarding the resilience of companies' networks and their effectiveness in restoring consumers' supplies following severe weather. In our view, this is an integral part of quality of supply performance, which to date has not been recognised in the incentive scheme as it does not affect the "average year". As recent events have demonstrated, it is nonetheless of particular importance to customers.

Balance Between Financial and Other Forms of Incentive

As noted above, the key considerations in setting the balance of incentives should be consistency with the revenue allowance and a level of risk that is consistent with the allowed cost of capital. We believe that, other than in respect of network resilience, this points to limited (if any) new financial incentives.

Form of the Incentive Scheme, Targets and Incentive Rates

As noted above, any financial incentive schemes must in our view be symmetrical, with equivalent prospects for an identical magnitude of reward as for possible penalties.

We are not aware of any evidence that the treatment of planned interruptions in IIP is leading to a perverse incentive to accelerate or delay investment depending on quality of supply performance in the year to date. We do not therefore see any justification for amending the current IIP scheme in respect of planned outages.

Development of The GOSPs

We firmly believe that the Multiple Interruptions Guaranteed Standard (MIGS) needs to be reviewed from basic principles. This standard imposes open-ended risks on DNOs that even companies with world class performance could not hope to meet in every case. In particular, it will never be economic to provide urban standards of performance in rural areas (which is implicitly assumed in the standard). In our view, the aim of Guaranteed Standards is that DNOs should be able to manage their operations such that there would be no failures. We therefore firmly believe that the MIGS should be removed in favour of a more generic output measure in relation to network resilience (as discussed above).

Ofgem ask whether it is appropriate to include some Overall Standards in the IIP incentive scheme. Our view is that the more that such output measures are brought into financial incentive schemes, the more the nature of the business is being changed, exposing DNOs to more risk and consequently a higher cost of capital. We see no reason to change the current treatment of the Overall Standards that warrants this additional risk.

We do not have the systems to make automatic GS2 payments. At the last review this was viewed as uneconomic, and we firmly believe that is still the position.

Comparing Quality of Supply Performance

We agree that the results of the disaggregation work being carried out should be an important input into the determination of relative targets across companies. It must also be a key input into any cost/quality model, although as noted above we do not consider that it is possible to derive a robust comparative model of capex across companies.

The disaggregation work to date has focused on customer density and length of overhead line/underground cable. There are also other differences between company performance caused by the particular characteristics of the region in which they operate. For example, Southern Electric Power Distribution's region is the most heavily wooded. As a result, tree cutting is a key factor affecting the performance of the network. Another example is the additional distances to be travelled and consequent increased travel times in Scottish Hydro-Electric Power Distribution's area necessary, for example, to restore customers' supplies after an outage.

How Frontier Performance Could be Rewarded

The Initial Consultation states that Ofgem intend to reward frontier performance in terms of quality of supply, based on comparison of actual performance rather than in relation to IIP targets. This suggests that there could be reward for improvement even if a DNO fails to achieve its 2004/05 targets, but provided it remains a frontier company. However, we are unclear what Ofgem mean by the frontier in this context. Is it the companies that are the least cost or those that have, for example, the lowest customer minutes lost? If it is the latter, it will be necessary to ensure that "high" or "best" quality of supply is defined in terms of relative performance taking account of all of the underlying factors explaining that performance, including the disaggregation work and the issues raised above.

The Treatment of Exceptional Events

In our view, it is vital that exceptional events are excluded from IIP otherwise DNOs would be exposed to the significant risk of not meeting targets due to exogenous events. Work to date by Ofgem's consultants has focused on setting materiality and exceptionality tests based on CIs, CMLs and the number of faults. The assessment of whether and to what extent an exceptional event should be excluded is carried out at the annual IIP audit.

We do not believe that such an ex-post basis of assessment should be applied to exceptional events to be excluded from Guaranteed Standards. The current arrangement is by the application of the "Force Majeure" exemption, and we strongly believe that this provision should continue. This exemption is a key protection to the DNOs against risk from exogenous events. To apply an ex-post arrangement whereby DNOs would make compensation payments to all customers under the GSs and then recover the costs back through the price control would be an onerous, costly and unnecessary burden, particularly given that the current arrangements can work perfectly adequately.

If Ofgem wish to define "Force Majeure" more precisely, then we would suggest a methodology which links the exclusion of the event more directly to the exogenous event i.e. when a particular weather event is anticipated, for example, certain wind speeds. This would also link more logically to the way in which DNOs escalate their plans in situations of severe weather disruption.

Forecast Business Plan Questionnaire

We agree that Ofgem should consider through the Forecast BPQ the case for improving network resilience, in addition to improvements in CIs and CMLs, (including the accelerated upgrade of overhead lines and selective undergrounding).

Distributed Generation.

We welcome Ofgem's work to develop the price control framework to ensure that DNOs retain appropriate incentives with respect to the connection of distributed generation (DG). A specific feature of the development of DG is the uncertainty surrounding when and what type of connection will be needed in each DNO area. We therefore see some merit in what Ofgem has proposed in the consultation document and set out some detailed comments and proposals below. Similarly, we feel that the ideas put forward in Ofgem's associated discussion paper on Innovation and Registered Power Zones could be developed and have responded separately to that paper.

SSE's main concern, in relation to distribution investment to support DG, is to establish with certainty that the capital expenditure will be remunerated by earning a return on the RAV. As a consequence, we believe that significant expenditure that can be foreseen at the time of a price review should continue to form part of the price control review process of determining allowable capital expenditure over the succeeding price review period.

However, we would agree with Ofgem that to cover situations where there is still significant uncertainty at the price review that a particular investment will be needed, and to cater for unforeseen requirements arising during the price control period, a mechanism that rewards investment made within a price control period to meet DG requirements is needed. In our view, such a mechanism must retain the certainty that an acceptable rate of return will be available to remunerate the investment over its life, taking account of any additional risks borne by the DNO. If this basic requirement is not fulfilled, DNOs will delay making unforeseen DG-related investment between price reviews and substantial capability for accommodating DG will inevitably be delayed in these interim periods.

We have the following detailed comments on Ofgem's proposals, grouped under different headings for clarity.

Incentives for Network Access and Investment

Ofgem's proposed hybrid incentive mechanism for the accommodation of DG is made up of a pass-through element (element A) at a lower rate of return than the allowable weighted average cost of capital (WACC) plus a supplementary £/MW revenue driver (element B). We are of the view that this type of two-part mechanism has the potential to provide both the certainty on RAV return that is a necessary pre-requisite of any incentive scheme and also the actual incentive for DNOs to connect DG. However, we are not comfortable with the assumption that element A should entail a discount to WACC.

In the north of Scotland area, distribution reinforcement costs associated with DG connections could credibly range from zero to multi-million pound subsea cable investments. Even a half percent discount to WACC in relation to investments at the high end of this range would represent a significant shortfall of allowable revenue. Another aspect of the problem is the difficulty that Ofgem would face in setting the £/MW driver in element B of the incentive scheme. Given such a wide range of reinforcement costs, the driver would either over-reward low-cost schemes or fail to provide the basic WACC return for the higher-cost schemes.

In our view, element A of the DG incentive should provide pass through of all DG-related reinforcement investment at WACC, with the incentive and premium return provided through element B. At the start of the following price control period, the DG-related investment which has been "logged" under element A of the incentive scheme should be formally incorporated into the RAV in order to continue to be remunerated for the rest of its asset life at WACC.

There would, in these circumstances, be a similarity between the regulatory treatment of load-related and DG-related capital expenditure. In the former case, an overall annual level is determined in advance when setting the price control, but actual investments made are subject to review at the time of the following price control discussions and added to the RAV. The difference in regulatory treatment for DG-related expenditure (i.e. the premium return element) is justified due to the need to overcome disincentives to connect DG, to incentivise the connection of actual MW of DG, and to allow for the uncertainties and costs surrounding the increased levels of DG.

It is worth considering what additional costs and uncertainties DNOs will face with increasing quantities of DG connecting to their systems. These include:

- In some cases, increasing quantities of DG will avoid the need for traditional investment in network asset reinforcement; thus an element of the premium rate will compensate for the loss of regulated rate of return over the lifetime of assets that would otherwise have been built.

- There will be costs associated with adapting network operations from a passive towards a more active management of the network.

- There is uncertainty on the MW quantities of DG that will actually connect and remain on the system once the enabling investment has been made.

- DG investment that will be remunerated through the DG incentive scheme will not be able to participate in the normal capex efficiency incentives, whereby the benefits of efficiency savings against capex targets agreed at the price review are retained by the DNO for a rolling five year period. Ofgem notes this effect at paragraph 5.37 of the consultation document.

- With the proposed change in the depth of connection charge which would be payable by DG towards a shallower policy, DNOs will have to fund the deeper reinforcement costs of such connections from allowable revenue. As discussed, these costs could be very significant and there is, at present, no means by which a DNO can refuse to make such a connection.

In element B of the DG incentive, the £/MW driver should be set to provide a premium rate of return to DNOs from the time that additional MW of DG capacity is made available. The most readily available measure of this is the additional MW of DG actually connecting, although this brings with it risks for the DNO that expected DG connections do not materialise as expected. In our view, the £/MW should be payable over a period of time – say 10 years – for every MW of DG connecting above an established baseline of already connected DG. This measure of MW should include those embedded within demand connections, for example CHP schemes.

It appears to us that there will be some difficulties in establishing an appropriate £/MW figure to be used for all DNOs in all circumstances and Ofgem acknowledges that different rates may be appropriate for different voltages and types of connection. In our view, DG investment costs will vary between DNO areas and, in the case of large DNO areas such as the north of Scotland, could vary considerably within them.

This also raises a number of issues with the DNO's duty to connect. It is clear that any proposals which entail a pass-through of costs at a discount to WACC plus a £/MW term may in some circumstances not provide sufficient revenue to recover the deep reinforcement cost. This applies irrespective of the specific figures used to define the incentive scheme. Accordingly, we firmly believe that any scheme which does not allow full pass-through at WACC must also include a right for the DNO to refuse to connect particular generators in circumstances where the price control will not allow legitimately incurred costs to be recovered.

A further factor that makes the £/MW figure(s) difficult to establish for each DNO is the potential change in connection charge boundary signalled in Ofgem's distribution charge structure proposals. Up to now, the connection of DG has been on a "deep" basis with the generator seeing all the costs of accommodating the connection in the deep connection charge. This has meant that practically all recent DG connections in our DNO areas have sized themselves or chosen network locations such that reinforcement is not required. With the introduction of a shallower boundary of connection, it is likely that more DG will connect where reinforcement is required, since they will not individually see all the costs of the connection. Thus, the average cost of connecting DG is likely to rise substantially. Furthermore, many aspects of this proposed change in connection boundary have still to be clarified, and it could be some time before a more predictable pattern of £/MW connection costs emerges. It will therefore be difficult to make an assessment of future £/MW connection costs based on historic information such as that being provided in the DG business plan questionnaire.

Under our proposal that element A of the incentive scheme covers the asset-related costs of the DG-related investment, the main function of element B could be regarded as the provision of a broad incentive to DNOs to make DG connection capacity available once the costs and uncertainties highlighted above have been covered. This could be based initially on assessments of connection costs. The incentive figures, although based on connection costs, would also have to provide the premium level of return over the time that the £/MW figure was payable.

<u>Incentives for Network Operation</u>

Ofgem discuss in the consultation paper what measures might be implemented to incentivise appropriate operation of the network by DNOs in relation to DG. We understand the rationale for incentivising DNOs in operation of their networks to maximise the DG MWh output that can be achieved from the connected DG capacity, but feel strongly that the sorts of cost minimisation incentives considered at transmission level are inappropriate for the more complex distribution networks. Existing price control incentives and benchmarking analysis on operating cost efficiencies will ensure that DNOs always seek to operate their systems efficiently.

Many factors outwith DNO control will influence actual output from DG. Thus we agree with Ofgem that deciding upon, and quantifying an appropriate measure of network availability may be problematic. However, there appear to be us to be two situations where operational factors will influence DG output and where DNO activity could be incentivised. Firstly, where DNOs could use some contracted services from DG as an alternative to network reinforcement and secondly, where more active management of the system might allow more DG to connect. Both situations involve additional operating costs, which normal price control incentives would lead DNOs to minimise. Our proposal for both of these situations is to allow the expenditure to be capitalised and added to the RAV. In some cases, such projects might be suitable candidates for the enhanced RPZ incentive, which is the subject of a separate Ofgem discussion paper and on which we have responded separately.

<u>Other Points</u>

Ofgem mentions in the consultation paper other developments that are relevant to the development of DG incentives: in particular, developments in distribution charge structure and the proposed distribution losses incentive. We have strong views on the former and, in relation to the latter, have separately discussed with Ofgem our concern that some types of DG connection will actually increase distribution losses.

On distribution charge structure, we firmly believe that a change to a shallower connection boundary for DG should not be accompanied by the development of use of system charges to generators. In our view, reinforcement costs not supported by the connection charge paid by generators would be funded through use of system charges payable by demand and these are not likely to be significant in the early years of the next price control. For example, a £100m investment in DG related reinforcement, if spread across the demand base of a typical DNO would equate to perhaps 5% of that DNO’s allowable revenue over the years that the investment was in the RAV. As distribution charges represent only about 25% of customer bills, the final effect on demand customers of this significant capital sum would be little more than 1% of a customer’s electricity bill. At some stage, however, as DG-related costs become significant in some DNO areas, it would be appropriate to consider a method of equalising the costs on customers across Great Britain.

Assessing Costs.

Assessing Efficiency in the Base Year

We understand why Ofgem might wish to revisit the methodology for assessing relative efficiency at the current price control review and, as part of that, to consider the use of a range of statistical techniques. However, we consider that the benchmarking and regression techniques used in previous price control reviews are robust and that the adjustments to achieve comparability, bearing in mind that DNOs are essentially very similar businesses, are well understood, both to define the average efficient company and to decide where the frontier might lie. Any new technique could introduce as many uncertainties as it removes. We therefore support the use of:

- a top down (i.e. regression) analysis of controllable operating costs to assess the average efficient company and where the frontier might lie. Analysis on the basis of the 14 DNOs, the 8 groups, and to compare groups with the same number of companies could help inform the assessment;

- bottom up modelling of load and non-load related capex; and

- bottom up modelling of R&M costs (recognising that this may not be the primary method of evaluating R&M but provide valuable information for the efficiency analysis).

We are particularly concerned that the use of some of the techniques identified by Ofgem, especially those that involve benchmarking at the total cost level, will produce undue "clustering" of relative efficiency. We believe that this would be particularly the case with Data Envelope Analysis. More generally, we are not convinced that it is possible to effectively benchmark capital expenditure between network companies.

Unlike operating costs, there are a substantial number of variables that legitimately explain variances in capital expenditure across DNOs, including: network size; quality of supply; network resilience; load growth; historic system configuration; topography and geography of the authorised area; network losses; historic capital expenditure; and the extent of distributed generation. We do not believe that with only 14 observations (representing only 8 independent management groups) there will be sufficient degrees of freedom to robustly account for these differences and hence the statistical error terms in any such analysis are likely to be substantial. We note that Ofgem are considering using the total cost approach to benchmark fault costs. In our view, however, the factors we have noted that explain variances in capital expenditure, apply particularly to fault costs.

There is therefore a real danger that these models could inappropriately penalise efficient companies that have invested in their network in recent years and hence the statistical approach to assessing efficiency could in itself damage future incentives to invest in the network.

In terms of any assessment of operating costs, we agree that it will be appropriate to normalise the data to take account of any undue differences across companies in, for example, the allocation of common costs and capitalisation policies. However, we are not clear that it has actually been agreed by all DNOs that the activity analysis in the RAGs is the best way of achieving this. We note that there were two specific adjustments made at the last review for factors that could not be captured by a benchmarking model. These were: additional fixed costs for London and north Scotland to reflect, respectively, the higher cost of living in the capital city and the cost of servicing the islands. In our view, it is important that these costs are recognised outside of the benchmarking process.

Ofgem also suggest that it will be important to consider the effect of mergers in assessing relative efficiency. We see no reason to treat efficiency savings from mergers any differently from other sources of efficiency savings, and indeed we do not know how precisely this could be achieved.

One option would involve "adding back" some fixed costs to the independent DNOs for the purposes of the efficiency comparison. However, there are only three independent DNOs at present and, of these, one is linked to a large Water and Sewerage Company, which must convey substantial economies of scale and scope that may merit a separate adjustment. Another is part of a vertically integrated group which, again, probably conveys some economies of scope in shared services. Against this background, we do not see any justification for any financial adjustments due to corporate structure and we do not believe that the absence of any such adjustment would provide "artificial incentives to merge".

For all merged companies, provided they have achieved a minimum of £12.5m (the target set at DPCR3) efficiency savings across the merged companies, then no further merger savings should be required.

We are also concerned that a merger adjustment would involve a "double penalty" for those merger transactions that have been subject to the £32m "merger penalty". We particularly object to the suggestion that Ofgem may attempt to anticipate the synergies from future mergers in their assessment of costs. This would suggest a bigger upfront merger penalty than Ofgem's declared £32m per lost comparator. If such an approach were to pursued by Ofgem, we believe that it would raise significant issues of regulatory risk for merged DNOs since it would involve a retrospective departure from the declared merger policy.

Setting the Base Year Allowance

As noted above, we are supportive of the general regression methodology for assessing relative efficiency adopted at the last distribution price review. However, we do not believe that the "frontier" costs approach to projecting future costs used at that review was an improvement on the "average" cost methodology used previously.

In particular, the approach used at the last price review provided no reward 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. Furthermore, 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.

We note that the importance of rewarding the frontier companies has been recognised by OFWAT in the current price control review in the water industry. We would strongly urge Ofgem to similarly acknowledge that it is vital to incentivise the frontier companies to continue to drive the frontier forward, particularly since it is the performance of those companies that determines the price control outcome for the whole industry and hence all customers.

We support the commitment to a fixed retention period for both capex and opex savings made after 1 April 2003. We also welcome the commitment to apply these principles to the transmission price controls.

The mechanics of both of these incentive terms may not be straightforward. We would therefore urge Ofgem to provide more detail about how these mechanisms will work in practice. To that end, we welcome the commitment to applying the capex incentive term to all capex efficiencies, regardless of how they have been achieved. We also welcome the commitment to including the depreciation saving as part of the overall capex efficiency saving under the incentive.

However, while we support the fixed retention period for operating costs we do not believe this mechanism alone will resolve the periodicity problem. In particular, we firmly believe that so 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.

We believe that the only way to resolve this issue is to relate future operating cost allowances to factors that are, as far as possible, exogenous to the individual company's past performance. We therefore consider that the use of an "average cost" methodology to setting allowances for future operating costs would provide the optimum incentive going forward. 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. 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.

By contrast, we would firmly disagree with Ofgem's assertion in the document 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. In our view, there is a real danger that the fixed retention period will further reward those companies in contrast with the frontier companies.

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 review. Indeed, 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, we are concerned that this reinforces the poor incentive framework for frontier companies.

For the avoidance of doubt, we are supportive of the fixed retention period for operating cost savings, particularly given the fact that the marginal investment necessary to achieve future savings is likely to be much greater than in the past. However, in our view, it is vital that this methodology is 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.

Assessing Future Costs

There are many significant upward pressures on the expected operational costs of DNOs over the next price control period. Some of these, such as S74 Lane Rentals, the ESQC regulations and the Multiple Interruptions Guaranteed Standard have been recognised by Ofgem. Others include the forthcoming Private Mobile Radio and telemetry frequency change and the change to the background of mapping systems, which impacts particularly on Southern Electric Power Distribution. We have listed and discussed these additional cost pressures in Appendix 1. Clearly, we believe that it is vital that Ofgem's proposals fully recognise the additional costs discussed.

We note that Ofgem intends to conduct Total Factor Productivity analysis to inform the assessment of the scope for future efficiency savings across DNOs. This raises three issues. Firstly, this statistical technique is heavily reliant on a number of key assumptions including, in particular, the scope for continuation of the "privatisation effect" (which we think should be set to zero) and for capital substitution. The results also tend to be sensitive to the comparator group of industries chosen in the analysis. Given these sensitivities, we believe that Ofgem will need to be particularly careful in interpreting the results of any TFP analysis.

Secondly, it is clear that whatever the results of TFP analysis, it will not routinely take into account the industry-specific costs highlighted above. Accordingly, we believe that Ofgem will need to separately assess these costs and make appropriate adjustments to the forward-looking cost projections on a company specific basis.

More fundamentally, we do not believe that it is appropriate for Ofgem to attempt to predict future efficiencies over and above economy-wide productivity improvements (which are already accounted for by the application of the RPI-X term). In particular, the RPI-X framework is designed to *incentivise* companies to reveal the potential for cost savings. Given the position of DNOs in the regulatory cycle, there is a real danger that any of Ofgem's forecasts based on TFP could significantly over-estimate the scope for future efficiencies. This would raise issues of regulatory risk which would need to be reflected in the cost of capital. These concerns were less significant in previous price control reviews given the greater scope for cost reduction at that time. In any event, it is clear that to the extent that Ofgem forecast future cost reductions, cash allowances will need to be explicitly provided in the price control to cover the investments necessary to realise those cost reductions.

Historic Business Plan Questionnaire

Ofgem note that 2003/04 outturn cost data will be available before publication of the final proposals. However, we do not believe this data is relevant, given the commitment to rolling retention of efficiency savings. In fact, to take 2003/04 costs into account could undermine this incentive and reinforce the periodicity problem. For this reason, in DPCR3, 1998/99 outturn data was deliberately not taken into account by Ofgem in the cash flow model.

Forecast Business Plan Questionnaire

We welcome the commitment from Ofgem to make greater use of companies' own capex forecasts. We also welcome Ofgem's intention to develop their understanding of companies' forecasting processes. This should lead to a more informed assessment of DNOs' business plans.

However, we are concerned about the volume of information requested in the draft forecast business plan questionnaire. The forecasts are to enable an assessment of the costs of an efficient company for each year to 2010 (i.e. to understand at a high level why costs are expected to change, and to adjust for company-specific differences). We do not understand why the level of detail requested is considered necessary and we are concerned that despite a substantial cost to companies in compiling this information, very little of the data will actually inform the price review.

Asset Risk Management Survey

We do not see any reason to revisit the Asset Risk Management (ARM) work as part of the review. While we were supportive of the concept for the ARM, we have some significant concerns about aspects of the overall methodology adopted by Ofgem's consultants. If Ofgem are therefore determined to undertake another ARM survey, we would welcome the opportunity to discuss in detail the proposed methodology. We would also urge Ofgem to ensure that any further work on the ARM is postponed until the work on business planning is complete.

Financial Issues.

Obligations with Respect to The Financing of Companies

We agree with Ofgem's aim to seek to ensure that an efficient company should be able to earn a return on its RAV that is at least equal to the allowed cost of capital. The cost of capital by definition is set for the industry i.e. the average company. It follows therefore that the average efficient company should be allowed to earn a return on RAV equal to the allowed cost of capital. More efficient companies should be allowed to earn a higher return, and inefficient companies should expect to earn a lower return. This is how a competitive market would work.

The Cost of Capital

The fundamental issue on the cost of capital is that it must be set at a level that will incentivise companies to invest. The Smithers & Co report broadly supports the way in which the cost of capital has been arrived at in the past. However, we believe that the current return in the price controls is not sufficient to attract the capital required to undertake the likely step-change in investment over the next price control period and beyond. We therefore believe that an increase in the allowed cost of capital for the network companies is required at the next price control review.

We agree with Ofgem that, as far as possible, the cost of capital should be assessed on the basis of forward-looking rates. We also support using a level of gearing consistent with maintaining a credit rating comfortably within the investment grade category. However, in our view, it is unreasonable not to take into account historic debt that is now out of the market. Such an approach would create incentives for companies to seek more short-term arrangements for debt finance, which would not be appropriate.

We see no reason at this time for any changes to the financial ringfence, bearing in mind that the DTI have consulted separately on the introduction of a special administration regime. We note that there will be a separate consultation if other changes are anticipated.

Post-Tax v. Pre-Tax Cost of Capital.

There is little real discussion in the Initial Conclusions paper about whether it is appropriate to set the cost of capital on a post-tax versus a pre-tax basis. We see no reason why this cannot be resolved early on in the price control review, which would remove one of the many uncertainties currently facing DNOs.

We would support moving to a post-tax cost of capital at the next price control. In the past, Ofgem have used a pre-tax cost of capital in setting the price controls on the basis that this provides network companies with a strong incentive to manage their tax liabilities efficiently (by allowing companies to out-perform the regulator's assumptions). However, in our view, this is no longer appropriate for the following reasons:

(i) *Changes to the tax rules:* The tax treatment of capitalised non-load refurbishment expenditure changes with effect from 1 April 2005. This is as a consequence of changes in the interpretation of tax law introduced by the Inland Revenue in Tax Bulletin 53. The Bulletin states that expenditure currently treated as revenue for tax purposes (i.e. 100% tax deduction in the year expenditure was incurred) will be treated as qualifying for relief in line with the accounting depreciation rates for accounting periods starting after 30 June 1999. The industry has reached agreement with the Inland Revenue that for distribution non-load refurbishment expenditure the changes will apply from 1 April 2005 to coincide with the next distribution price control review.

However, these changes to the tax rules will have a significant financial impact on distribution businesses. Moreover, it will have different impacts on different companies and DNOs may be arbitrarily penalised or rewarded on this kind of generic basis, by the use of a common tax wedge. A pre-tax methodology may therefore be best suited to industries where the tax position of companies is similar;

(ii) *Gearing:* We agree with Ofgem that a pre-tax cost of capital incentivises companies to adopt higher levels of gearing which, in turn, could inappropriately reduce the financial flexibility of a company. In addition, a pre-tax cost of capital may be over-generous to companies that are highly leveraged; and

(iii) *Consistency:* calculating the cost of capital on a "post-tax" basis is currently the methodology applied in the water industry, and a move to this approach would bring more consistency between regulators.

Calculating the cost of capital on a post-tax basis would then raise the issue of how to set the allowance for tax costs. There are broadly two options:

(i) An "ex-ante" allowance in each DNO's price controlled allowed revenue, similar to the way in which rates were treated at the last distribution price review; or

(ii) an ex-post pass through of actual incurred tax liabilities, similar to the way that NGC Exit charges are treated in the current distribution price control.

Although an "ex-post" pass-through of actual tax costs would bring certainty of recovery of costs, it would not incentivise companies to maximise tax more efficiently (i.e. by out-performing the regulator's assumptions). We therefore believe that tax allowances should be set on an ex-ante company specific basis. Under this framework, DNOs would be allowed to retain efficiency savings in tax for a fixed period of time, as with other cost savings.

In setting the ex-ante allowances for future tax liabilities, we firmly believe that Ofgem must recognise the change in tax rules which will result in a significant increase in future tax costs for companies. In addition, to date tax costs have been recovered through a generic uplift to the cost of capital calculation (the "tax wedge"), in order to arrive at a cost of capital on a "pre-tax" basis. The tax wedge used in the last distribution review cost of capital calculation was 30%. However, for most companies the effective tax rates have been closer to 23%. In our view, this difference between the effective tax rate and the allowed tax wedge represented a strong but hidden incentive to invest, which needs to be replaced. We therefore believe that in setting future allowances for tax Ofgem should take into account the *incremental* increase in tax liabilities of network companies.

In conclusion, it is not clear that a post-tax basis would weaken the incentive to manage tax positions efficiently. Indeed, it would become clearer how companies have performed against their allowance. There appears to be no evidence to the contrary in the water industry. Further, a post-tax regime would also provide a mechanism for dealing with any future tax changes, for example changes suggested under the Reform of Corporation Tax. This would provide reasonable certainty of recovery of costs while retaining some scope for out-performing the regulator's assumptions. If a post-tax cost of capital is adopted by Ofgem we believe that the tax allowance should be set on an ex-ante, company specific basis, taking into account the incremental increase in future tax costs.

<u>Assessing the RAV and the Approach to Depreciation</u>

We welcome Ofgem's confirmation that it does not intend to change the method used for assessing the initial value of the RAV. We also support the proposed five year retention period for RAV adjustments following asset disposals.

However, we are disappointed that Ofgem have not taken the opportunity afforded by this paper to confirm the approach to depreciation that will be taken at the next price review. In particular, it is disappointing that Ofgem have not confirmed that, in common with the practice adopted at the last price review, a twenty-year depreciation profile will be applied for all investments of all companies when the vesting assets are fully depreciated. We firmly believe that such an approach is appropriate for the following reasons:

(i) Accelerated depreciation was applied to four companies at the last distribution price control review and was expected to be extended to the remaining DNOs at DPCR4. The underlying requirement for the adjustment remains and it is essential that all companies are treated the same. Indeed, we firmly believe that if the same policy is not applied to all companies, this would be inconsistent with Ofgem's price control principles of transparency and consistency (as set out in the initial conclusions paper);

(ii) The full depreciation of the vesting assets will, other things being equal, lead to a cliff-edge in prices followed by increasing prices thereafter. Accelerated depreciation will help to manage the transition following depreciation of the vesting assets;

(iii) Given the nature of the UK equity market we do not believe that investors are willing to be remunerated for investments over a 40 year cycle, encompassing eight price reviews, with all of the associated risks; and

(iv) We do not believe that a twenty-year depreciation cycle would distort inter-generational balance of prices between present and future customers, as suggested in the consultation paper. Indeed, we do not believe that the current 40-year cycle applied in the price control reflects the benefits to present customers of current investments.

For these reasons we would urge Ofgem to commit to the use of a 20-year depreciation profile in the forthcoming distribution and transmission price control reviews. Although this would not affect the value of cashflows in net present value terms, it would resolve a major uncertainty facing network companies in the price review.

Treatment of Pension Fund Costs

With regard to the summary of the guidelines which were published in the June 2003 document, we have given our detailed comments in our response to that document. However, we highlight here two of the issues with which we are particularly concerned:

- *Liabilities in respect of the provision of pension benefits that do not relate to the regulated business should not be taken into account in assessing the efficient level of costs for which allowance is made in the price control.*

  We have serious concerns about this guideline, which we believe needs clarifying. Following the creation of separate businesses as a requirement of the Utilities Act the other PES businesses, and we use the supply business as an example, might reasonably be expected to accept liability for the provision of pension benefits for those employees current at the time. However, it is not reasonable for them to accept liability for existing PES pensioners (and in any case it is not possible to identify precisely in which business those pensioners were employed). The cost of pension obligations caused by these past employees derives from statutory obligations that network companies cannot avoid.

  Prior to business separation all employees and pensioners were employees and pensioners of the regulated PES. Customers funded pensions through the price control and it is appropriate therefore that customers of the current price controlled businesses (i.e. the network companies) should continue to fund the pensions of those PES pensioners, including the deficits. If pension costs were to fall in the future then network company customers would benefit.

- *Companies will also be expected to absorb any increase (and may retain the benefit of any decrease) in the cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.*

  This guideline is totally unacceptable, being based on a false presumption that companies have received allowances for pension enhancements in previous reviews.

  In the first case there has been no increase in benefits. The rule that a full time employee, with 5 year's service when made redundant, is entitled to the payment of the pension from age 50, not normal retirement age, has been a pension scheme rule since before privatisation. It is therefore an ongoing cost borne by the pension scheme from surpluses. It is not a new or increased cost.

  Secondly, the cost of pensions, whilst funded by way of a pension scheme, is an obligation of the company. Any shortfall in a scheme has to be made up by the company and in terms of FRS 17 the assets and liabilities of the scheme are recognised as assets and liabilities of the company. The balance of cost falls upon the company. It is therefore incorrect to differentiate pension scheme assets from company assets. The cost of meeting pension promises, normal or enhanced as a result of severance, is a cost to the company like any other cost and is not affected by whether or not a company paid contributions to the scheme.

Ofgem argue that the previous price control made an allowance for the cost of restructuring and that if a company used a pension surplus to fund a part of that cost, and thereafter customers pay costs arising from a consequent deficit, then those customers will be paying twice for severance. We do not believe that this is correct. In particular, the last price control did not include a specific allowance in respect of redundancy costs. There were modest allowances for restructuring, but it is not clear that this was intended to recover redundancy and in any event the amounts involved fall considerably short of the actual costs incurred for severance and paid directly by the company.

For these reasons, we would reject any suggestion that DNOs have in some way benefited from "gaming the system" with enhanced pensions benefits. Accordingly, we would be firmly opposed to any proposed adjustment to cost recovery to "strip" these costs out of any pension fund deficit.

Future Pressure on Operating Costs. **APPENDIX 1**

S74 Lane Rentals.
Section 74 of NRSWA already establishes a penalty regime for road openings that last longer than previously agreed with the local authority. The Lane Rentals trials currently being carried out in Camden Town and Middlesbrough represent a change in the incentive mechanism moving to an upfront fee for opening roads. If extended more widely this will represent significant additional costs which companies will incur and will have to be passed on to customers. Roads have to be opened in the daily course of our work, and Lane Rentals in our view represents nothing more than a "tax" which DNOs and hence electricity customers will have to pay. We also understand that there are proposals to widen local authority powers such that they can direct when and where DNOs can open roads. This is clearly inconsistent with other incentives, for example to restore supply in the event of an underground fault. It would also change the way companies work and prevent them from operating at optimum efficiency.

ESQC Regulations
The ESQC Regulations are set by the DTI Inspectorate. The full implications of the recent amended Regulations are still being assessed, but will involve additional costs to DNOs, for example keeping additional records of potential hazards around their networks.

Multiple Interruptions GS
The likely compensation and administration costs associated with this Standard are still unknown. However, it is certain that they will increase as customers become more aware of the Standard.

Electricity (Connection Charges) Regulations (Amended) 2002
As from June 2003, DNOs will be required to refund part of the connection charge to customers who have paid the full cost of a new connection, should a "second comer" wish to make use of that connection. This will require DNOs to introduce systems to record where that might apply.

Competition in Connections and Metering
It should also be borne in mind that the introduction of competition e.g. in Metering and Connections, brings additional costs to the network monopoly. For example, in the past DNOs would provide a single design and quote for a connection. However, following the introduction of competition, DNOs now have to provide quotes for non-contestable works to several competitors.

As these businesses become competitive, and market share is lost, staff numbers in these businesses will fall. This will significantly reduce the numbers of experienced and trained staff available to the DNOs to assist in a system emergency. Bearing in mind that DNOs are already under considerable cost pressure, and that revenue is capped, the balance between efficiency and critical mass is of concern. It is therefore vital in the current review that Ofgem take into account practical ongoing operational effectiveness when assessing the results of the theoretical economic efficiency models put forward by the consultants.

Tree Cutting
It has been suggested in the IIP-related work on disaggregation, that tree cutting and travel costs are manageable and therefore that these will not be disaggregated. It follows therefore that if DNOs are to be expected to meet the same targets in these instances then the relative cost differences need to be taken into account. For example, this should reflect the fact that SEPD is one of the most densely wooded DNOs and at the same time encounters considerable public reaction to tree cutting.

North of Scotland
Similar recognition of travel times and associated costs of operating in the North of Scotland, as was made in DPR3, would also be necessary (although the £2m adjustment made at DPR3 was in our view insufficient). The remoteness of the Highlands and the difficulty of getting to the Islands, particularly in bad weather, means that the efficiencies in operating procedures that the average DNO can make, are not available to the same extent in Scottish Hydro-Electric Power Distribution's area.

Wayleaves
It is increasingly being found that customers expect higher wayleave payments than historically. In addition it is becoming more difficult to obtain the most economic route for a line, and therefore the associated wayleave costs for schemes are rising.

Customer Expectations
Not only are customer expecting continually higher standards of service, but as they become more aware of the electricity market, they are also contacting us more often.

Change to GIS Background (County Series Maps)
SEPD's GIS system is based on the County Series maps. It is understood that these are to be withdrawn and therefore that we will have to change the mapping background to GIS. We expect this to require a significant manpower resource and to be a major cost.

PMR and Telemetry Frequency Changes
In order to be consistent with the rest of Europe, DNOs and other utilities and emergency services are having to change the frequencies on which their radio communication and remote network control equipment operate.

Congestion Charges
A congestion charge has been introduced in London. We would expect such charges to be also introduced in other towns and cities.