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Our ref	Your ref	Date
591 (M1)	145/04	9 August 2004

Dear David

WPD Response to Ofgem's June Paper

I attach WPD's comments to the June paper. The issues raised are those mentioned during our presentation to the Gas and Electricity Markets Authority ("the Authority") on July 19th, together with issues on the mechanics of metering separation.

The response concentrates on those areas where WPD disagree with Ofgem's position in the June paper. There are a number of areas that are therefore not discussed because WPD agree or support Ofgem's position. The principal area of support is IIP, where the use of clear definitions and audits of data have significantly increased the transparency and objectivity of the incentives for performance. We look forward to a similar result being achieved during DPCR4 for cost information – where the outputs should include clear definitions of DNO activities against which auditable direct unit costs could be collected and compared.

The principal areas where WPD disagree with Ofgem's position are:

The CSV used in the regression

The CSV is by definition, Ofgem's view of what the cost driver for total variable operating costs is in every DNO. Ofgem's CSV includes three components – network length (50%), MPANs delivered to (25%) and units delivered (25%). The only evidence that has been presented to Ofgem is the analysis undertaken by WPD that shows that around 96% of DNOs costs are driven by asset volumes.

Ofgem have not provided analytical justification for the CSV but we are aware that other companies have put forward the view that although customer numbers is not a cost driver, it is a proxy for other factors such as the degree of urbanisation that have a fundamental effect on costs. This view has not been supported by any analysis nor is there any indication of what sort or volume of costs customers act as a proxy for. In fact as the presentation made to Ofgem on August 5th shows (Appendix 2 to this submission, slides 11 to 15) the data supports the views that (a) costs in urban areas are better correlated with network length than customer numbers and (b) that overhead networks are more expensive to maintain than underground networks. On the other hand, based on the total of all DNO's BPQs, costs associated with overhead lines and underground cables represent 88% of directly incurred costs associated with assets, and should therefore provide a justifiable proxy for all assets.

At the presentation to the Authority we were asked to provide a comparison of the network costs incurred in Bristol with those is North Devon to illustrate how costs vary in urban and rural areas. This information is attached as Appendix 3 to the comments on the June paper. Once one drills down into the information for smaller network areas one-off events can have a disproportionate effect on the numbers for any particular year. The overall results show that the costs per kilometre are consistent but the costs per customer show a significant disparity, as set out in table below:

		Bristol		North Devon
Customer Numbers		272,603		88,525
Network Length (km)		4,574		5,241
UG Length (kM)		4,040		946
OH Length (kM)		534		4,295
Total Cost per Customer	***£***	***9.24***	***£***	***24.47***
Total Cost per Network Length (km)	***£***	***550.52***	***£***	***413.33***

The use of the incorrect CSV coupled to the ongoing 2% efficiency factor has the effect by 2010 of reducing WPD's allowed controllable operating costs by £19million from 2002/3 actuals compared to a total frontline labour cost of £28million.

Calculation of Allowed Capital Expenditure

Although we agree that a sliding scale incentive mechanism is appropriate to reward realistic forecasts, the 'PB Power view' is constrained to companies' submission where the PB Power model exceeds the companies' submission. The effect of this is asymmetric because it selects the lower of the company's forecast or the result of the PB Power model before applying further reductions, thereby unfairly penalising those companies whose BPQ forecasts were modest. The incentive should be recalculated without the constraint to avoid this perverse incentive.

Pension costs

We reiterate our view that it is incorrect not to allow all the deficit costs arising from early retirement deficiency costs ("ERDC"). However we recognise that the solution discussed in the June paper, that 70% of the ERDC costs associated with distribution should be allowed, because customers have received at least 70% of the benefits resulting from the staff reductions since 1990 that gave rise to the ERDCs.

Other matters

As mentioned during the presentation on July 19th there are a number of specific technical issues that we believe should either have been resolved or are in the process of being resolved and in relation to which we await Ofgem's views. These issues may require further discussion and include, but are not limited to:

- The calculation of excluded revenues
- Ofgem's tax calculation
- The calculation of the weighted average cost of capital
- Allowed capital for diversions
- Regional factors
- The RAV roll-forward

I hope the comments above are useful look forward to discussing them with you.

Yours sincerely

Robert

RA SYMONS
Chief Executive

Cc Sir John Mogg- Ofgem
Cemil Altin - Ofgem

Electricity Distribution Price Control Review Initial proposals - June 2004 - 145/04
Response From:

Western Power Distribution (South West) plc

Western Power Distribution (South Wales) plc

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Chapter 3 Form, structure and scope of revised price controls

Para 3.7 Revenue Driver

The proposed basket weightings in Table 3.1 do not agree with the company's view of the relative weights that should be applied calculated on a yardstick basis. There is no explanation of the basis used by Ofgem in deriving the published weights so it is not possible to comment on the value of their adopted method.

Para 3.15 Non-contestable connection charges

WPD's response to Ofgem's initial thoughts were included in the response to the Competition in Connections document.

Para 3.17 Business Rates

WPD welcomes Ofgem's recognition of the efforts made to minimise business rates costs and its current proposal not to disallow any of these costs. As a pass through item WPD would expect to see these costs treated as a separate identifiable item in the price control. Similarly OFGEM Licence fees should continue to be a separate identifiable price control pass through item.

Para 3.19 Revenue Protection

WPD believes that revenue protection is best carried out by supply businesses. However should Ofgem determine that revenue protection would be a distribution activity then the function should be treated as an excluded service. Revenue protection is not a core activity of the distribution business and the costs/revenues associated with performing the function are difficult to predict at the present time.

Para 3.33 Uncertainty – Traffic Management Act

WPD agrees that that any costs associated with the Traffic Management Act should be considered in isolation from companies' financial performance under the price control. Therefore we believe that this would be best achieved by treating such costs as pass through throughout the period of the price control.

Providing a fixed allowance based on a single year of operation of the Act will expose the company to a significant risk over which has very limited control. The level of prices may vary significantly and also the level of activity will be dictated by factors such as the economic activity in the area.

Para 3.33 Uncertainty – ESQCR

WPD agrees that that any costs associated with changes to ESQCR should be considered in isolation from companies' financial performance under the price control. However the assumption that work resulting from the changes is likely to cause excess costs from 2008 may not be valid. Where adequate clearances do not exist safety considerations may prevent deferring the work. The DTI have not been prepared to give any dispensation to allow such deferral.

Costs in this category should therefore be treated as a pass through item for the period of the price control.

Para 3.44 Losses

Ofgem have proposed an increase in the incentive rate for reducing losses. The increase may encourage changes to network plant and design. However such changes would only be achieved very gradually and would not affect the network for decades.

In contrast the apparent level of losses is subject to the smooth running of the settlements system and the settlements system that has experienced significant poor performance. In addition the inclusion of EHV sales and their associated losses means that the level of losses will be influenced by the activity in this market sector over which DNOs have no influence or control.

Overall the increase in the incentive rate adds to the short-term risks of the company.

Para 3.45 Target for Losses

As noted in other responses to Ofgem the target level of losses should be based on the simple average of the latest 10 years of data, without any additional weighting. Although the apparent difference in the target loss percentage is small it as a significant implication on the reward from reducing losses. Over the 5-year period of the price control the estimated cost of the difference is £4m.

Chapter 3: Metering Separation

Para 3.52

Ofgem are proposing an Average Revenue Cap form of price control for MOp. We are concerned that no detailed information has been provided to enable a full understanding of how such a mechanism will work. If the detailed structure of the average revenue cap is such that it reasonably reflects variable costs, addresses the recovery of fixed costs and recognises the increase in variable costs associated with reducing volumes, then WPD will not oppose such a proposal.

However, Ofgem appears to be linking the average revenue cap to the number of meters provided. Using number of meters as a driver for MOp revenues may not reflect the true costs drivers. Costs in the business depend for the most part on the number of MOp transactional services provided, or visits made. The bulk of the work for a MOp is the removal and replacement of meters that have reached the end of their certified life. This is not related to the volume of meters but to the re-certification programme. The table below shows the re-certification programme for South Wales and the South West over the next 5 years. As can be seen, volumes vary considerably over this period. Costs will follow volumes and allowed revenues should be based on the cost profile and therefore, in part, services provided.

Year	South West	South Wales
2005	69,900	25,068
2006	60,259	96,182
2007	92,135	36,889
2008	126,010	44,512
2009	73,789	51,749

WPD welcomes the recognition that the relationship between the drivers for MOP and the allowed revenues should not be directly proportional and that the unit price will rise as volumes reduce. This reflects both the need to cover fixed costs and the increased relative costs per unit as volumes and density reduce.

Para 3.53

As a DNO that has licence obligations to provide MOp services, WPD will carry the associated fixed costs. We will have no choice but to retain those costs until the licence obligations are removed. If we cannot recover those fixed costs through the remaining MOp service charges, then they must be recovered from within Distribution - effectively a cross subsidy.

Para 3.59

We are concerned at the method of calculation used to derive the price cap ranges given in table 3.3 and would welcome a detailed explanation of those calculations. The provision of a meter asset is comparable to that of making a loan of the value of the asset, to be repaid over the economic useful life of the asset, at a rate of interest equal to the cost of capital. As such, a straightforward annuity calculation based on the current price of the meter asset appears more transparent than a calculation based on the total asset values of a particular category of meter.

Having said that, we support the concept of setting price caps that reflect the variable nature of the expected life of the meter asset. This variability could be addressed by allowing early return fees based on the outstanding economic useful life, or by increasing the cost of capital to recognise the risk of volatility in respect of useful life, or by ensuring that the allowed range at the top end gives sufficient flexibility to permit the bilateral negotiation of commercial terms that manage the risk of early return.

Para 3.55

We support the inclusion of PPM in the price control on a price reflective basis. This is a significant improvement on the current situation where the additional costs of pre-payment meter provision and maintenance are recovered through a surcharge of dubious accuracy. Making these charges cost reflective will give the appropriate messages to all parties that should result in future decision making being more soundly based.

Para 3.60

Whilst we understand that costs vary between individual DNOs, it should be recognised that the historical allocation of costs between Capex and Opex and between Distribution and Metering and between MAP and MOp do not provide a sound basis for setting price controls going forward. This is particularly so for MOp (see 3.61 below). In our view, the price caps for MAP should reflect the actual asset provision costs and useful economic lives pertaining to each DNO, but the allocation of operating costs and overheads should be, if only broadly, of the same order going forward.

Para 3.61 and 3.62

The opex numbers submitted as part of the BPQs are reflective of the way costs have been allocated historically and vary between DNOs. As such they do not include all the costs that will have to be recovered through MOP transactional income in future. In particular, in WPD, those opex numbers do not include the cost of installation of a new meter or the cost of changing a meter due to functionality change, both of which have historically been allocated to capital. Those historic costs have therefore been recovered through RAB depreciation and cost of capital allowances, and the outstanding value of those costs will rightly be recovered in that way until all historic costs have been recovered. In future, the costs of installing new meters and changing meters for functionality reasons will fall on MOp, and MOp will charge a transactional charge for doing the work. It is essential that the MOp allowance includes the appropriate income from all transactional activities, not just those included in historic opex.

Para 3.63

WPD welcomes and supports Ofgem's intention to allow an operating mark up for MOp to reflect the non-capital nature of this activity. To position the DNOs on a market related footing, our expectation is that this mark up will be of the order of 10 to 15%.

Para 3.64

Of critical importance for MOp is the need to formulate the average revenue cap in such a way that it can adequately deal with substantial step changes in volumes and mix over time. Whilst preferring a straightforward approach, it must also be robust in dealing with such volatility without the need to re-open the control. Key elements of the control will be:

- selection of appropriate drivers that accurately reflect costs and mix
- weighting factors that reflect changes in cost per unit with overall volume
- inclusion of a fixed cost element reflecting continuing licence obligations

Until the detailed explanation of the way in which the average revenue cap is to be calculated is available, it is neither possible to model the outcome of its application nor to assess the risk or sensitivity of the model. Consequently, it is not possible to comment on the acceptability of this proposal.

No mention has been made of the mechanism for recovery of stranded costs resulting from the impact of reduced market share on resources provided to meet licence obligations. It is our expectation that the fixed cost element of any average revenue cap will be adjusted to permit the recovery of any such costs.

Para 3.66

WPD supports, in principle, the concept of 'basic' services being as existed at 1 April 2003. However, in practice, the detailed proposals on licence obligations need to be reviewed before further comment can be made. .

Para 3.71

WPD supports the proposal to remove licence obligations from 1 April 2007 and accepts the need to retain control over assets in place at that time. However, this should all be subject to competitive review on an annual basis, with obligations removed earlier if the opportunity presents itself. This would prevent DNOs being left with costs necessary to provide services, without the income to cover those costs.

In summary, we note that some progress has been made in respect of the principles to be used for a separated metering price control. However, we are concerned at the lack of available detail in respect of both the MAP price cap and MOP average revenue cap calculations. There is insufficient detail for us to model the impact on income, or to estimate the risks, and thereby reach an informed judgement as to the adequacy of the proposals. We urge Ofgem to make that detail available as soon as practical and certainly no later than the update document in September.

Chapter 4 Quality of Service and other outputs

Para 4.60 – 4.62 Storm Arrangements and Associated Cost Allowances

In respect of the standards and incentives for the restoration of supplies following severe weather events, we agree with Ofgem's detailed proposal in respect of:

- Simplifying the "gates" for exceptionality so that they are based on the number of faults in a 24-hour period;
- Introducing a shorter time threshold for payments of 24 hours for "medium sized" wind and snow events and all lightning events;
- Raising the cap on the distribution companies' exposure from 1 to 2 per cent of price control revenue; and
- Replacing the cost pass-through mechanism with DNO specific annual allowances.

However, we suggest that the proposed "gate" for very large severe weather events, i.e. 50% of exposed customers, is too high. The proposed gate corresponds to 300,000 and 390,000 customers for WPD (South Wales) and WPD (South West) respectively. In December 1993, both WPD (South Wales) and WPD (South West) experienced a very severe storm. At that time 190,000 and 216,00 customers respectively were affected. Allowing for growth in customer numbers, this equates to 33% and 31% of current exposed customers respectively. As this corresponds to the largest storm that we have experienced over the last 10 or so years, we suggest that it would be a sound basis for defining the "gate" for the very large severe weather event.

In addition, there is no reference to the level of payments to customers. We propose that compensation payments should start at £25 when the trigger period has been reached, with £25 increments for each additional 12 hours. The maximum payment to an individual customer should be capped at £200.

Para 4.51 – 4.53 Audits and Adjusting Data for Inaccuracy

We agree with Ofgem's proposals to continue with streamlined audit and to tighten the overall accuracy requirements from 95 to 97 per cent over the next price control period.

However, we do not agree with Ofgem's proposals to adjust each DNO's reported output to take into account any inaccuracy identified by the audit. This would introduce an unnecessary level of uncertainty for DNOs without any consequential real benefits to customers.

Para 4.63 – 4.70 Incentives for the Speed and Quality of Telephone Response

We agree with Ofgem's proposal to simplify the arrangements associated with the existing quality of telephone response incentive scheme.

However, we do not agree with the proposal to include a question relating to a customer's satisfaction with the speed of telephone response in the survey. As the speed of telephone response can be measured objectively, we propose that the speed of telephone response should be incentivised independently.

We agree with Ofgem's proposal to introduce a separate survey that focuses on exceptional events. During exceptional events the majority of customers would receive automated messages. Therefore, for such a survey to be representative of customer's views it would be necessary for the survey to include customers that received an automated message.

Para 4.71 – Undergrounding in Areas of Outstanding Natural Beauty

We are disappointed that OFGEM have proposed that no additional expenditure should be allowed to reduce the visual intrusion of overhead wires in designated areas. By taking no action on this issue it is suggested that OFGEM have missed a clear opportunity to enable small, but significant amounts of new money to be put into undergrounding wires and in doing so are ignoring their statutory duties to National Parks and Areas of Outstanding Natural Beauty and paying no regard to the principles of sustainable development. We urge OFGEM to reconsider this issue.

The consumer research undertaken as part of the Distribution Price Control Review has highlighted that consumers concerns embrace a range of environmental concerns including the visual intrusion of overhead lines in the landscape. It is the principle duty of OFGEM and all DNOs to protect the interests of these consumers, of whom 89% gave their support for undergrounding in designated landscape areas (94% by businesses). The second phase of the consumer research has shown that there is willingness to pay 0.7% on top of the current bill to enable further undergrounding to take place. Although this is a small percentage, it would result in significant resources for undergrounding compared to the current situation. It is misleading to compare this amount to the total cost of undergrounding all wires in these landscapes – the latter is clearly not feasible at present, nor has it ever been argued for.

Para 4.76 – 4.78 Environmental Reporting

In response to earlier consultation on proposed environmental reporting measures under the RIGs, WPD were supportive of measures relating to leaks from fluid filled cables, and reportable environmental incidents. Constructive comments were provided in respect of SF6 reporting measures and a widely drawn, undefined, proposal relating to "visual amenity".

It is noted that work is continuing in consultation with the DNOs, and the previous comments made by WPD still stand. We are supportive of the concept of a small number of meaningful environmental indicators, and these comments are aimed at helping Ofgem achieve this.

SF6 Reporting

Ofgem will be aware that the development of the European Directive of Flourinated Gases is not yet complete, and UK Government (primarily DTI/ DEFRA) last met with "F Gas Stakeholders" on 14th May (next meeting ? September) . The

European requirements for reporting, and the transposition of this into UK law are still not settled.

It would be inappropriate and wasteful to have a reporting requirement to Ofgem, which was different from that which will be required under the UK transposition of the Directive. In broad terms WPD would not have difficulty reporting of volume in use / volume lost (we have reported on this basis to former EA) , but we will need to review the situation when the new UK legislation appears, including consideration of any de-minimis thresholds, and would want to use a common basis of reporting to UK Govt and Ofgem.

Visual amenity

It is concerning to see reference to reporting " visual amenity including heritage and landscape" as such issues are already heavily covered by legislation, planning controls and regulation. It suggests a lack of understanding of measures already in place, covering SSSIs, national parks, heritage coastline etc. and illustrated by the following list of some of the applicable legislation –

- Ancient Monuments and Archaeological Areas Act 1979
- Contaminated Land (England) Regulations 2000
- Electricity and Pipe-line Works (assessment of Environmental Effects)
- Regulations 1990
- Electricity Works (Environmental Impact Assessment) (England & Wales)
- Regulations 2000
- Environmental Protection Act 1990 & 1995
- EU Habitats Directive 92/43/EEC – Special Areas of Conservation
- Land Drainage Act 1991
- Noise at Work Regulations 1989
- & Country Planning Act – General Development Order 1990
- Water Resources Act 1991
- Wildlife and Countryside Act 1981

Chapter 5 Distributed generation, IFIs and RPZs

Para 5.8 - Pass Through Rate

We continue to believe that the pass through rate for IFI should be higher. This is supported by the RIA as it concludes that the 'potential value derived through innovation considerably exceeds the cost of the IFI/RPZ incentive'. The projects with lower risks are likely to proceed in year 1 and 2. It therefore seems counter productive to reduce the IFI pass through to 70% by year 5 when more research with a higher risk of failure may be needed.

Para 5.15 - RPZ Incentive Rate

Whilst the increase in the RPZ incentive rate from £3/kW to £4.5kW is welcome, the risk/reward balance is still unlikely to incentivise us to seek out RPZ projects.

Chapter 6: Cost assessment

Composite Scale Variable

Ofgem have used a composite scale variable to compare the costs of companies that is weighted 50% to network length, 25% to customers and 25% to units distributed. The composite variable is incorrect because it does not reflect the underlying costs drivers for DNO.

WPD has undertaken a study of what the cost drivers of DNOs are that is supported by the results of PA Consulting study for Eurelectric in 2002. WPD's report concludes that:

a) The CSV has to be based on detailed research and the detailed research shows that the CSV should be at least 96% weighted to DNOs' assets.

b) Based on information in the HBPQs and in the absence of detailed UK benchmark costs by the asset types in the Eurelectric report, network length weighted to overhead network in the ratio of the order of 1.34:1 should be used as a proxy for assets.

A copy of the WPD study including a copy of the PA consulting report is attached as Appendix 1. A copy of WPD's presentation of the study to Ofgem is attached as Appendix 2. Apart from the issues discussed in the report, it provides data that indicates that LV underground faults are more likely to be driven by network length than by service connections or customer numbers.

Ofgem and DNOs have discussed the CSV and have discussed WPD's report. No overall agreement as to what the CSV should be was reached. However, what was generally accepted was that:

a) Assets drive costs

b) Customer numbers do not drive costs

Most companies did not agree with WPD that network was a good proxy for assets, even though overhead line and underground cable costs constitute nearly 90% of companies' direct costs in the BPQs. Some companies argued that although customer numbers/units is not a cost driver, it is a proxy for other factors such as degree of urbanisation that it is claimed affect unit costs. No basis was given as to why customer numbers or units should act as a good proxy, nor any analysis provided of what costs customer numbers or units act as a proxy for, nor why customer numbers should be a better proxy than any other, including network length, especially when the BPQ data submitted by companies indicates that in general underground networks are cheaper to operate than overhead networks. In general, no other company made any analysis available nor was any factual basis for their view disclosed.

Regional Factors
In the absence of a CSV that reflects WPD's cost drivers the regression will not be accurate in representing WPD's relative efficiency. WPD has [1.22] times the assets per customer of the average DNO. In addition, 60% of the network is overhead and therefore carries with it a greater opex cost per kilometre. Therefore, in the same way that LPN receives an allowance for higher operating costs in London, WPD should receive an allowance for the sparsity of its network. A report on how sparsity affects costs has been prepared by NERA and is attached as Appendix 4 to this response.

Opex Normalisation and Regression

Ofgem's approach to cost comparison is to first adjust the submission in an attempt to achieve comparability between companies and then to regress the results. The costs chosen to be regressed are operating costs and faults. Costs that are capitalised are excluded before the regression is undertaken. This process of normalisation and comparison is unlikely to produce reliable results because:

a) An incorrect CSV is used (discussed above)
b) The distinction between direct and indirect costs is arbitrary and distorts the data (discussed below)
c) Ofgem conflate "Indirect Costs" with "Overheads" (discussed below)
d) The order of making the adjustments is incorrect (discussed below)

<u>Direct and Indirect Costs</u>

Ofgem's distinction between direct and indirect costs is based on a distinction between those employees that fill in time sheets and those that do not. This is not a distinction between whether costs are directly incurred in the course of an activity but a difference in how employees account for their time. As such, distortions are produced because, for example:

a) Team Managers are responsible for the day to day work that occurs on the network, their costs are directly incurred as a result of network operations in organising and controlling the staff that undertaken routine maintenance, faults and new connections. However, Team Managers do not account for their time on timesheets and as such are treated as indirect costs by Ofgem.

b) Team members, directly engaged in day to day operations may, as a result of their employment history, not complete timesheets. As a result a significant minority of employees working for Team Managers also do not complete timesheets.

In other business structures Team Managers, or their equivalent would, by completing timesheets "become" direct costs. Ofgem do not appear to have undertaken any work to ensure that such differences do not distort the data.

“Indirect Costs” and “Overheads”

Having defined as “Indirect” all staff costs that are timesheet-accounted, Ofgem then go on to take the further step treating all indirect costs as overheads. This is incorrect. An indirect network cost such as network control is not the same as an overhead such as finance or treasury. To conflate “Indirect Costs” and “Overheads” makes it even more difficult to properly assess what the efficient costs of a DNO should be because whereas indirect costs will vary with the primary business activity, overheads are largely fixed.

Order of adjustments for capitalisation

Ofgem’s approach is first to make the normalisation adjustment, and then to regress the results for opex. The normalisation adjustment for capitalisation is based on using an average percentage capitalisation rate for “overheads” (the definition of which is discussed above). Even assuming that the definition of “overheads” to which the percentage is applied was correct, the effect of making the adjustment in this way is to either ignore or misstate the extent of any inefficiency in overhead costs. This can be demonstrated by the following example. Assume two companies have identical networks to operate and that their direct costs are also identical, in the example below, we know what the actual degree of inefficiency is, but Ofgem’s normalisation exacerbates the inefficiency already obscured by capitalisation:

Normalisation adjustment for capitalsation policy

	DNO A	DNO B	In-efficiency
Total Overheads	**£100**	**£150**	**£50 *Actual* inefficiency**
Less capitalised overheads (50% and 40%)	**-£50**	**-£60**	
Overheads included in opex	**£50**	**£90**	**£40 Inefficiency per BPQs**
Ofgem normalise - both capitalise 45%	**£55**	**£83**	**£28 Inefficiency per Ofgem**

Apart from data quality the problem is created by the order of the normalisation process. If the order of the normalisation process were adjusted then, given consistent data and supportable CSV, the process would yield reliable results. The revised order of the process would be:

1. Undertake a regression of all costs, including *all* direct opex and also *all* indirect costs (i.e. including those that have been capitalised- but excluding direct capex)

2. Use the results of the regression to adjust companies’ costs to the level of efficiency required by Ofgem.

3. After the adjustment in (2) above is made, deduct from the result that proportion of costs that should be capitalised by applying a consistent percentage

4. The result of (3) above is the efficient opex

5. DNO's capex forecasts would need to be adjusted to ensure that only the amount determined as being capitalised in step (3) is allowed.

<u>Cost comparison conclusion</u>

In Ofgem's regression one of the companies forming the upper quartile (YEDL) is only there as a result of significant adjustments made by Ofgem to capitalised overheads and indirect costs as part of the normalisation process. The method used for making the adjustments is incorrect and the data to which the adjustments are made is inconsistent and the comparison uses the wrong CSV. At the very least, unless the methodology is changed the capitalisation adjustments within normalisation should be abandoned.

Chapter 6: Capital Expenditure

Review of future capex

Para 6.73 – 6.78:

The PB Power modelling approach is covered in the separate Capex reports and we have responded separately to these, however the PB Power modelling approach of assessing efficient forecasts as being the lower of their modelled output or our submission masks the efficiency is our investment proposals and hence penalised rather than rewards companies that have put forward realistic investment proposals. Additionally the PB Power report clearly states that if the ESQCR compliance costs are excluded then an extra £13.5m should be added for LV overhead line refurbishment – this has been left out of the PB Power view in table 6.7 despite the exclusion of the ESQCR costs.

Para 6.86:

We disagree with the adjustments made to WPD S West and WPD S Wales diversions forecast. The adjustment appears to have been made based on allowing the lower of the diversions forecast for DPCR4 or the forecast outturn for DPCR3, however the DPCR3 forecast that has been used only covers the period 2000/01 to 2002/03 and hence at best represent only 3/5th of that required. Additionally no account has been taken of changes in activity level between the DPCR3 and DPCR4 period.

Para 6.87

As stated above, an allowance for LV overhead line refurbishment is needed if the ESQCR compliance work is delayed.

Para 6.92

We support the principle of the sliding scale mechanism however, it should be assessed against a common benchmark for all companies (e.g. the PB Power modelled investment requirement) rather than the lower of the PB Power modelled investment requirement or our submission. This would ensure that companies making realistic forecasts and hence a higher risk of overspend against their forecast are more likely to be rewarded.

Table 6.9 and 6.10

We understand that there is no direct linkage between the stylised version of the sliding scale reward mechanism and the numbers used for the price control calculations. We are keen to understand a practical implementation of the mechanism, as the stylised version appears to give significantly higher rewards than those included in the price control calculations.

Para 6.105

Whilst allowances have been given for capitalised fault costs, these have effectively been scaled down by the regression work carried out on operating costs even where PB Power have assessed companies as being efficient in delivering capital works. This scaling is unjustified.

Chapter 7 Financial Issues

Taxation

We consider that some aspects Ofgem's tax modelling to be inappropriate for WPD:

- Paragraph 7.11 sets out the assumption that a revenue tax deduction will be allowed for capitalised faults and non-operational capex. However, as previously discussed with both Ofgem and Ernst & Young, this expenditure will follow the rules set out in Tax Bulletin 53, and any tax deduction will equate to the depreciation charged on those assets through the profit and loss account. It is our understanding that this tax adjustment has been used as a proxy to take account of the ability of companies that outsource to capitalise a larger proportion of overheads but receive a revenue tax deduction. Ofgem have since acknowledged that this was not appropriate for companies that never have, do not now and never intend to outsource and, as the WPD companies are in this position, this adjustment should not be made i.e. this expenditure should be treated as capital expenditure as deferred revenue

- No account has been taken of capital expenditure that does not qualify for any tax relief e.g. easements, land, as this was considered not to be material. This is currently up to 4% of total expenditure and is therefore material

- The model assumes that the capital expenditure split for tax purposes has been done on the basis of the 2003 tax computations. However, this does not seem to be the case as the proportions are substantially different. We will forward to Ofgem comments/changes that we deem appropriate to both the capital expenditure splits and opening tax pool balances on receipt of the calculations by Ernst & Young as agreed with Ofgem

- Incentive payments should be determined on a gross basis and the ensuing tax liability should be taken into account in the price control calculation tax

- In the price control allowed revenue calculation interest is determined using a real rate (currently set at 4.1%) based on a theoretical CAPM cost of capital approach. However, in the determination of tax cash flows a nominal rate of interest (currently set at 6.7%) is used. For consistency, Ofgem's price control calculation should determine tax cash flows ignoring inflation, with all tax inputs including interest set in real terms

Pensions

WPD's reaffirms its agreement with Ofgem's principle that recognition of pension costs associated with regulated distribution and metering activities should be included in the allowed income for DNO's

WPD support Ofgem's view that the liability relating to active members be allocated according to their present employment. As previously stated it is not possible for

WPD to classify the activities undertaken by post-privatisation leavers during their entire employment on an individual basis. However, as a pragmatic approximation of their employment history we are able, for South West, to classify individual post-privatisation leavers on the basis of their employment on the date of retirement/leaving. We do not have the data to undertake this classification for South Wales because we do not have historical data, although South Wales total liabilities for South Wales could be allocated based on South West data.

WPD reiterates that allocation of pension fund assets should be in proportion to liabilities. An allocation based on a matching assets approach would not, in our view, be practical or possible to achieve with any degree of accuracy.

In relation to Early Retirement Deficiency Costs, we continue to strongly disagree with Ofgem's view that companies should be penalised for not making payments into the scheme at the time it was in surplus. We reiterate our view that Ofgem should recognise the true benefit to customers from the staffing efficiencies already achieved that result, broadly, to a 70/30 split in favour of the customer. Therefore at least 70% of past ERDC's should be allowed for. It also follows to WPD that penalising those companies that have used surplus wisely in the past for the benefit of customers and their companies would amount to retrospective regulation that incentivises inefficiency.

WPD would support Ofgem with the type of approach outlined, which we believe gives Ofgem, customers and DNO's a fair and pragmatic solution.

WPD would strongly oppose applying a fixed allowance for future service costs because the characteristics of ESPS groups make the approach unreasonable. The level of the future service cost is influenced by factors outside of a DNO's control e.g. the average age of workforce, investment strategy, male/female ratios, mix of pre and post 1988 members etc. Therefore, future service costs should be allowed for in full, as certified by the actuary in the final valuation report for each group.

Appendix 5

Developing Regulatory Impact Assessments

(section on QOS)

Para 3.13

The most significant distributional effect is that all customers within a DNOs area will be affected by the costs of the proposed changes to the quality of supply arrangements, but only a subset of customers will experience a change in the level of quality of service.

We estimate that across all DNOs, the maximum percentage of customers who would experience a change in the level of quality of service would be in the order of 50%.

Para 3.15

Our assessment is that there are not likely to be any unintended consequences associated with the interruptions incentive scheme as the:

- Incentive rates proposed for the Customers Interrupted are not too strong so as to encourage inefficient investment; and

- Incentive rates proposed for Customer Minutes Lost should promote the desired behaviour.

Para 3.16

Our assessment is that the proposed changes to the quality of service framework will have no impact on competition.

Para 3.17

Our assessment of the initial proposals for changes to the quality of service framework is that, within a DNO and compared to the current framework, there would be no material increase in the cost of monitoring.

Para 3.19: Specific Questions for Developing the RIA

What would be the costs and benefits of each the proposed changes to the incentive arrangements? Can these be quantified?

The costs associated with the introduction of semi automatic compensation payments for failures to achieve the normal weather supply restoration standard are estimated as being in the range £10k to £15k per year for both WPD (South Wales) and WPD (South West). Customers would derive the benefit of receiving the compensation payments.

The costs associated with the introduction of semi automatic compensation payments for failures to achieve the severe weather supply restoration standard would vary year on year, depending on the weather experienced. However, as an allowance has been provided for making these payments, it has been assumed that the net cost on an efficient DNO is nil. Customers would derive the benefit of receiving the compensation payments.

The payment of compensation direct to customers, rather than via suppliers, would not add costs to a DNO. However, customers will derive the benefit of more timely payments.

The costs and benefits of the interruptions reporting scheme have been presented by Ofgem in the initial proposals document.

The costs associated with the storm arrangements have been presented by Ofgem in the initial proposals document. The benefits would be derived by customers through the receipt of compensation payments.

There are no costs associated with the simplifying of the arrangements associated with the existing quality of telephone response incentive.

What would be the impact of the proposed changes in each of these areas on other incentives in the price control framework (e.g. capex & opex rolling incentives/DG/losses)? - Our assessment is that the initial proposed changes to the quality of service framework would have negligible impact on other incentives in the price control framework.

Are there any additional costs of the introducing the revised framework to DNOs/Ofgem/other parties? If so, what are these?

Our assessment is that the initial proposed changes to the quality of service framework would not result in additional costs being incurred by DNOs, Ofgem or other parties.

Are there any impacts on safety? - Our assessment is that the initial proposals for changes to the quality of service framework would have no negative impact on safety.

What will be the impact of the proposed changes on the long term reliability of the networks?

Our assessment is that the initial proposals for changes to the quality of service framework would have no detrimental long term impact on the reliability of the distribution networks. In some circumstances, such as where DNOs are targeting a reduction in the number of unplanned incidents that occur, the proposed changes to the interruptions incentive scheme and the storm arrangements would have beneficial long term impact on the reliability of the distribution networks.

What are the potential costs and benefits of increased investment in network resilience? - Our view is that the most cost effective way of improving network resilience is effective operational management which includes ensuring that tree cutting programmes are effective and on schedule. This is consistent with the overall conclusion of the Network Resilience Working Group (NRWG) that the one overriding factor that needs to be addressed in order to improve the storm performance of electricity distribution networks is the proximity of trees to overhead lines. The benefit of effective tree cutting programmes would be a reduction in the amount of tree related damage to overhead lines during severe weather and a consequential reduction in the number of customers experiencing a supply interruption.

One investment scenario that was considered in the Forecast Business Plan Questionnaire was the impact on network resilience of under-grounding 2% of the overhead line distribution network.

Tables 46 of the Forecast Business Plan Questionnaire submissions for WPD (South Wales) and WPD (South West) indicate the costs associated with the scenario. Tables 48 indicate the anticipated changes in both overall quality of supply and distribution losses for the scenario. Appendices T46-48 of our narrative responses provide background information. We anticipate that under-grounding 2% of the distribution network would result in a minimal improvement in network resilience.

Are these measures likely to benefit all consumers connected to the DNOs' networks? - The initial proposed changes to the quality of service framework are not likely to benefit all customers connected to a DNOs distribution network. However, all the customers within a DNOs area will be affected by the costs of the initial proposed changes to the quality of service framework.

We estimate that across all DNOs, the maximum percentage of customers who would experience a change in the level of quality of service would be in the order of 50%.

Which consumers are likely to gain most or benefit least from the changes? - The customers that are most likely to gain most from the initial proposed changes to the quality of service framework are those located in rural areas (.i.e. customers connected to HV circuits that comprise more than 20% overhead line).

The customer that are most likely to benefit least from the initial proposed changes to the quality of service framework are those located in urban areas (.i.e. customers connected to HV circuits that comprise less than 20% overhead line).

Appendix 6

Structure and scope of price control licence modifications and DG, IFIs, RPZs- RIGs - Version 1.

Timetable

WPD welcomes Ofgem's initiative in forming a joint working group to progress the legal drafting of licence modifications needed as a result of the DPCR outcome. WPD is represented on the Working Group. A detailed response to this Appendix is being prepared by the DNO Working Group.

We believe that the timetable is challenging but achievable with the full co-operation of Ofgem and Industry representatives.

Proposed New Structure for the price control licence conditions (Para 3.17)

And Regulatory Reporting Framework (Para 7.4)

In principle, we would support the proposed structure for price control licence conditions based on revenue allowances (within Special Conditions), and requirements for cost reporting, revenue reporting and output reporting (within Standard Conditions), provided that Regulatory Instructions and Guidance are subject to change control procedures that give both flexibility and safeguards.

Core price control restriction with additional conditions for pass through items and incentives (Para 4.5 and 4.6)

In principle we would support separate special conditions for pass through items and incentive mechanisms as this provides flexibility without reopening the core price control settlement.

Replacing Special Condition Schedule A with Regulatory Instructions and Guidance (Para 4.9)

We do not agree that Schedule A could become part of Regulatory Instructions and Guidance, with the exception of Part A A1-3. However the information requirements within Schedule A would be more appropriate within a standard condition covering all the revenue recording and reporting requirements.

Parts C & D should remain explicitly within the Special Conditions as these are fundamental to the core price control.

B1 and B3 relating to EHV premises may become part of the core price control and so should remain part of the Special Conditions as a core definition.

The treatment of Distribution Losses under Part A A4 and Part C may need to be a new Special Condition.

Supply Restoration Licence Condition (Para 5.10)

In principle we would like to see the Interim Arrangements formalised. The DNO Working Group is looking at ways of achieving this.

Distributed generation, Innovation Funding and Registered Power Zones. (Para 6.4)

One aspect that needs to be clarified is the operation of the GCt term ('compensation' to the generator for network availability being below a baseline level in the Gdt formula). As written, the formula reduces DNO allowed income the amount of the 'compensation' payment. The 'compensation' payment needs to be defined as negative regulated income within the basic price control (i.e. it's part of the tariff for the generator). If however the 'compensation' payment is left outside of regulated revenue then it would be deducted from DNO income twice.

As above, Regulatory Instructions and Guidance should be subject to change control procedures that give both flexibility and safeguards. Any definitions relating to terms of the Incentives Schemes under the Special Conditions should be within the Special Conditions.

Regulatory Accounts (Para 7.3)

We agree that the format for the provision of regulatory financial information needs to be finalised. The DPCR process has highlighted the need to collect information on a common basis, so as to monitor financial performance between price reviews and to inform future price reviews. WPD believes that Ofgem's information requirements for 02/03 are a good model for the future but these could be refined to show more clearly the direct costs of each DNO activity supported by clear definitions of what should be included in each cost category and no absorption of one activity's cost over another.

WPD supports the use of the statutory accounts format as the key published document. This is a standard format, recognisable to users, and therefore readily comparable. The regulatory accounts should therefore be the statutory accounts for the licensed company only (not consolidated), for the regulatory year.

The requirement to present the financial statements as if the licensee were a London Stock Exchange quoted company is not appropriate. Instead DNOs should provide a commentary including the key elements of an OFR (including comment on non-financial performance standards applicable to DNOs, treasury and insurance) statement of directors' pay and performance and corporate governance.

In addition DNOs should be required to submit cost reporting schedules based on the key elements of the financial factors underlying the DPCR. Users should be able to reconcile this data to values included in the statutory accounts. They should be subject to audit review. As the RAV is a key value for both DNOs and certain of its stakeholders (principally lenders of capital), then the roll forward should be agreed annually as part of this overall process and not on a five-yearly basis as at present. WPD believes that it is helpful to publish the cost reporting schedules.

We support the preparation of Regulatory Guidance and Instructions for the Cost Reporting Schedules. The draft RAGS together with the structure of information tables and associated definitions used for the DPCR process should provide the basis for this document. It is proposed that the DNOs be asked to submit their suggestions for the cost reporting schedules and RIGs. Ofgem should then produce a draft set of cost reporting schedules and RIGs for DNO comment. This process must be completed within the general timescale for licence modification.

A submission date of 31 July is reasonable provided that the final requirements are clearly established before the end of the regulatory year.

The issue of the Auditors liability cap also needs to be resolved and included in the RIGs. We would suggest a figure of £1 per connected customer for the cap to be included in the Auditor's Engagement Letter, and for this to be split 50:50 between the DNO and Ofgem.

Removal of licence conditions (Para.7.6 & 7.7)

We would welcome the opportunity to refine or remove licence conditions that are redundant as part of the discussions within the Joint Working Group.

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Composite Scale Variable

DNO Meeting

Thursday 5th August 2004

Comparison of Operating Costs

- The starting point for any comparison must be the analysis of what drives cost.
- Regression analysis is used to determine efficient operating costs using a CSV that is not underpinned by logic or fundamental analysis.
- r^2 values are the result of the cost comparisons not the rationale for it.

Composite Scale Variable

- WPD has produced a report that looks at what drives cost in a detailed way
- It is rooted in a practical view of how distribution businesses work at the delivery level
- We have cross checked it against the 2002 Eurelectric study of distribution cost drivers

Cost Driver Analysis

- Appendix 2 shows a complete line-by-line analysis of all DNO activity correlated to the cost drivers

Asset Driven Costs

Table 4

	% of variable costs
Maintenance/Inspection/Faults	63.3%
Transport	5.5%
Insurance	3.7%
Wayleaves	8.8%
Property	9.3%
Telecontrol/telecoms	4.2%
IT (excluding fixed)	1.3%
Total	96.1%

2002 Eurelectric Study

- Analysed 48 companies distribution costs (including some functions regarded as supply in the UK)
- Network is the major internal cost driver
- Customer costs are related to meter operation, reading, billing, debt collection and all customer calls – the vast majority being supply costs

DNO Cost Drivers

- If Ofgem's CSV was correct then if every residence in WPD's areas were subdivided into two flats with no increase in load or network, Ofgem would provide an increase in allowable operating costs of £16.2m with virtually no extra operating cost incurred.
- If WPD had twice the network with the same number of customers the incremental allowed costs would be half of the allowed current costs
- If WPD's load delivered doubled through better utilisation of the existing network Ofgem would provide an increase in allowable operating costs of £16.2m with virtually no additional operating cost incurred.

Network Length is a Good Proxy for Assets

Because :

- 88% of operating costs are directly driven by line length
- DNO’s have approximately the same proportion of network length to plant – the effect of discrepancies is insignificant

Plant and Network Opex

Table 7

Network Costs	£m	
Overhead lines (inc wayleaves)	167.5	39%
Underground cables	208.1	49%
Total network costs	375.6	88%
Switchgear	36.6	9%
Transformers	16.7	4%
Total	428.9	100%

* Source HBPQ Tables 20 & 26, total for all DNOs

Plant / Network Ratio's: Differences are Not Significant

- Using network length as a proxy assumes that all companies have the average amount of plant per network kilometre – companies with lower than average plant per km will gain, companies with above average plant per km will lose
- The range of values and the average for plant per network kilometre are:
  - Lowest 1.03 (NEDL)
  - Highest 1.55 (WPD South West)
  - Average 1.29
- Some companies will gain from the proxy (LPN, EPN, NEDL, EME and UU), but the gain will be small (WPD South West loses less than £1m as a result)

U/G vs O/H Cost per Kilometre

- Network length may be a good proxy for assets, but is overall network length sufficient or should there be a weighting between overhead and underground?
- Table 8 in our report shows that a weighting is required – overhead network requires more operating cost

UG vs OH Cost per Kilometre

Table 8

Overhead/Underground Costs*			
	Total Cost	Total Network	Cost/km
	£m	km	£/km
Overhead lines (inc wayleaves)	167	290,204	577
Underground	208	484,578	430

* Source HBPQ Tables 20 & 26, total for all DNOs

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Other Arguments

- LV U/G Network and faults costs are customer driven because:
  - Dominated by LV U/G fault costs
  - Faults usually occur at service joints
  - Service joints are driven by customer numbers
- If this was so:
  - LV U/G service / mains fault rates / 1,000 underground customers would be similar
  - LV U/G service / mains fault rates / 100kM would not be similar

Low Voltage Underground Cable Faults

(Evidence, London cf South Wales)

	EDF (London)	WPD (South Wales)	LPN/WPD(SWA)%
Underground Customers per Km of LV Underground Cable	114	77	147.8%
Customer Ratios	**EDF (London)**	**WPD (South Wales)**	**LPN/WPD(SWA)%**
LV UG Service Faults per 1000 Underground Customers	0.8	1.4	58.6%
LV UG Mains Cable Fault Rate per 1000 Underground Customers	1.9	2.6	31.0%
Network Length Ratios	**EDF (London)**	**WPD (South Wales)**	**LPN/WPD(SWA)%**
LV UG Service Faults per 100 KM	9.1	10.4	86.7%
LV UG Mains Cable Faults per 100 KM	21.7	19.8	109.6%

*Source: IIP Tables

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Low Voltage Underground Cable Faults

- The evidence does not support the view that customers drive LV U/G cable faults
- The evidence supports the view that network length drives LV U/G cable faults

Conclusion

- The CSV used in Ofgem's regressions has a significant impact on the allowed revenues in DPCR4. The conclusions of our analysis are:
  - The CSV has to be based on detailed research. The detailed research undertaken by WPD and independently supported by Eurelectric study shows that the CSV should be at least 96% weighted to DNO's assets
  - Based on information in the HBPQs and in the absence of detailed UK benchmark costs by asset types as in the Eurelectric report, network length weighted to overhead network can be used as a proxy for assets