Electricity Distribution Price Control Review

Summary of responses to March Policy paper

June 2004 145c/04

Summary

This document summarises responses to the March 2004 policy document on the price control review and sets out Ofgem's view on the issues raised.

Further details on policy issues and other areas of work are set out in the main initial proposals document and earlier documents on the price control review.

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1. Introduction

1.1. The purpose of this document is to outline the key points made by respondents to the March 2004 policy document on the price control review.[1]

1.2. Where Ofgem announced specific proposals or decisions within the policy document, these are highlighted in bold typeface, whereas respondent views are summarised in plain typeface.

1.3. This document should be read in conjunction with the document "Electricity Distribution Price Control – Initial Proposals", which is being published at the same time as this summary of responses.

[1] Electricity Distribution Price Control – Policy document, Ofgem, March 2004, 62/04

2. Form, structure and scope of the price controls

Form and structure of the price controls

Revenue driver

2.1. **Ofgem proposes to retain the broad form of the existing revenue driver so that it is weighted equally (50:50) between units distributed and the number of consumers – i.e. no capacity based driver will be introduced.**

2.2. DNOs were in favour of retaining the broad form of the revenue driver and the existing weighting between units distributed and the number of consumers. One other respondent stated that the units driver should be reduced to zero and replaced with another driver, as it considered that DNOs were being doubly remunerated for the theft element of losses via both the units driver and the losses incentive. Another noted an EC Directive proposal to remove the incentive for operators to increase the volume of energy handled and urged Ofgem to investigate alternative drivers early in the next control period.

2.3. **Ofgem also proposes to:**

- **use the actual number of consumers reported each year by the DNOs as defined in the IIP Regulatory Instructions and Guidance (RIGs);** and
- **review the weightings applying to the various voltage categories within the units distributed revenue driver.**

2.4. There was general support for the use of actual customer numbers in the revenue driver, with DNOs considering that this would be more cost reflective. However, one DNO had reservations about using the RIGs definition as this excludes certain classes of customer and the definition might not be consistently applied by all DNOs. This DNO also stated that using actual customer numbers may discourage the disconnection of MPANs, thereby affecting settlement systems data quality.

2.5. There were mixed views on the proposal to review the weightings of the voltages. Some supported this work, with the proviso that EHV customers are dealt with in an appropriate manner. One DNO expressed concern that work which could have a profound impact on allowed revenues was being started so late in the process.

Price index

2.6. **Views were invited on the appropriateness of using CPI instead of RPI within the forthcoming price control.**

2.7. Respondents generally favoured the continuing use of RPI, stating that this was a more relevant measure for DNO costs than CPI. Many also commented on the continuing use of RPI by other regulators. One respondent supported the use of CPI, but gave no reasons for this preference.

2.8. This issue is further considered in Chapter 3 of the main document.

The scope of the price controls

Transmission exit charges

2.9. **Ofgem does not propose to change the treatment of transmission exit charges at this review.**

2.10. All DNO responses welcomed the decision not to change the treatment of exit charges, though of the three non-DNOs that commented, two considered that there should be some element of incentivisation on exit charges.

Treatment of wheeled units

2.11. **Ofgem proposes to allow the pass-through of the costs associated with wheeling charges and to include the revenue associated with wheeled units within the price control.**

2.12. There was general support for this proposal, although one DNO considered that wheeled units should continue as an excluded charge. Two DNOs queried how capital costs to reinforce networks to facilitate wheeling would be dealt with under the proposal. One non-DNO stated that allowing pass-through of costs

associated with wheeling charges would affect DNOs incentives to be efficient in providing such services and so opposed the proposal.

EHV charges

2.13. **Ofgem proposes to include EHV charges within the scope of the price control.**

2.14. Opinion was split amongst DNOs as to the merits of this proposal. Some welcomed this as a way of protecting them against volatility in EHV revenues, while others considered the volatility in EHV units distributed as a prime reason that it should remain an excluded service. Many of the DNOs commented on the importance of determining an appropriate revenue driver for EHV if it is to be included in the price control. Five non-DNO responses welcomed the proposed inclusion of EHV charges within the price control. Two of these noted that it would be beneficial if EHV customers had the right to apply directly to Ofgem to have their charges determined, rather than having to apply for a determination through their suppliers.

2.15. **Ofgem proposes that charges for any new EHV connections made during the next price control period are treated as excluded service revenue until the next review in 2010, when Ofgem would expect to include them within the price control.**

2.16. Two DNOs welcomed the proposal to treat new EHV connections as an excluded service, considering that this would go some way towards mitigating the risk of DNOs. One other respondent considered that this brought little if any benefit to customers and requested clarification of the extent to which controllable EHV costs are being brought within the price control.

Non-contestable connection charges

2.17. **Ofgem does not propose to change the price control treatment of connection charges in respect of reinforcement for demand consumers for this price control.**

2.18. DNOs were supportive of this proposal but two other respondents considered that these charges should have been subject to an incentive mechanism under the price control. Some of the DNOs did not support the opening of network

reinforcement services to competition, claiming that it brought additional complexity and cost, and considered that it would be more beneficial to develop competition in other areas. A respondent who represented independent connection providers (ICPs) claimed that the current market structure gives DNOs the potential to cross-subsidise their connections businesses, thereby restricting the development of competition and so advocated the regulation of some non-contestable charges.

2.19. **Ofgem proposes to require DNOs to establish and publish a clear schedule of charges for non-contestable services directly relating to the existing monopoly network. If it appears that DNOs are charging an excessive amount for the services that they are providing, Ofgem will take necessary steps to ensure that consumers are protected. Ofgem intends to set up a working group with DNOs and ICPs to discuss the issue further.**

2.20. There was general support amongst both DNOs and non-DNOs for the work leading towards publication of a clear and transparent set of charges and some respondents expressed an interest in participating in the proposed working group.

2.21. **At present, voluntary standards of performance exist in relation to the provision of connection services – but only for new housing estates. Ofgem considers that these should be extended to cover all new connections.**

2.22. DNOs were in favour of the current standards remaining voluntary, while other respondents considered that such standards should be mandatory. One DNO considered that some of the existing standards were unrealistic in that a DNO's ability to meet them was not wholly within its control.

2.23. **Ofgem does not intend to attach financial penalties to these standards at this point**.

2.24. DNOs welcomed the intention not to impose financial penalties but one other respondent considered that there should be financial penalties where DNOs have acted inappropriately or outside accepted levels of service.

Other excluded services

2.25. **No change to price control treatment is proposed for**:

- **top-up and standby charges;**
- **non-trading rechargeables;**
- **other minor activities and charges.**

2.26. Three DNOs agreed with these proposals, but one considered that top-up and standby charges should be treated in an identical manner to EHV units so as to avoid a distortion of charges.

2.27. **Ofgem proposes that the treatment of units distributed to embedded networks should be consistent with that for wheeled units, i.e. included within the scope of the price control.**

2.28. Three DNOs agreed with the proposal that units distributed to embedded networks should be within the price control.

2.29. **Ofgem also needs to consider the treatment of costs and revenues associated with networks that DNOs operate outside of their authorised area (i.e. 'out of area networks'). Views are welcome on this issue.**

2.30. Two DNOs and one other respondent considered that "out of area networks" should be subject to the same form of regulation as other licensed distributors, but one other DNO was strongly opposed to this proposal, considering that these networks are part of a competitive market and that the proposed extension of regulation would undermine competition in this area.

2.31. This issue is further considered in Chapter 3 of the main document.

Business rates

2.32. **Ofgem would expect to make a decision on the treatment of rates in the June Initial Proposals**.

2.33. All DNOs highlighted the efforts they have been making with respect to minimising their rateable valuations for the coming period and the majority of

these DNOs recommended that rates should be given full pass-through treatment. One of these asked Ofgem to clarify any expectations it has in judging whether companies have acted appropriately in their discussions with the VOA.

2.34. This issue is further considered in Chapter 3 of the main document.

Hydro-benefit

2.35. **The Secretary of State has proposed legislation which would allow her to make an order to enable the Great Britain Transmission System Operator to provide a subsidy to a distributor with high costs by adjusting the transmission charges paid by all suppliers. Ofgem will set the price control to pass-through the benefit of any such subsidy to consumers**.

2.36. One DNO welcomed the Government's proposed amendment to the Energy Bill in relation to the provision of a subsidy to mitigate the effect of the removal of hydro-benefit. Ofgem also received a confidential response specific to this issue.

2.37. This issue is further considered in Chapter 3 of the main document.

Dealing with uncertainty, new obligations and costs

2.38. **Ofgem recognises that DNOs may need some protection and that some allowance will be made for certain costs that arise between price control reviews – although this should be restricted to a very limited number of specific cost items.**

2.39. All but one of the DNOs expressed a strong preference for a formal mechanism to deal with uncertain costs and supported the submission by the ENA on this issue. One DNO stated that given the potential magnitude of the costs involved, comfort letters were not an acceptable alternative.

2.40. This issue is further considered in Chapter 3 of the main document.

Duration of the price control

2.41. **Ofgem confirms that the duration of the revised price controls for the DNOs will be from 1 April 2005 to 31 March 2010.**

2.42. Three DNOs welcomed the decision to confirm that the price control would last five years.

Incentive framework

2.43. **Ofgem needs to consider the treatment of the benefits received by DNOs from asset disposals between 1 April 2000 and 31 March 2003.**

2.44. One respondent welcomed the intention to consider asset disposals, claiming that there had been significant divestitures as a result of the mergers that have occurred during this price control period.

Definition of costs and incentives

2.45. **Ofgem is considering changing the existing treatment of costs so that:**

- **where types of costs are substitutes (e.g. refurbishment after a fault or at other times), incentives should be equalized as far as possible; and**
- **where definitional boundaries are difficult to set or enforce, incentives should also be equalized as far as possible.**

2.46. **One impact of these changes would be, all other things equal, to increase the amount of costs being capitalised and included in the RAV. Ofgem welcomes views on this suggestion.**

2.47. The majority of DNOs that responded on this issue were not in favour of this proposal, with some highlighting that it affected the incentive properties of the entire price control framework and the ability of DNOs to outperform the price control assumptions. Two DNOs suggested that it should be possible to classify costs in a more rigorous and prescriptive manner to overcome the perceived problem of inappropriate cost allocation.

2.48. This issue is further considered in Chapter 3 of the main document.

Incentives for investment deferral

2.49. **One option would be to reduce the incentives that companies have to defer investment from April 2005 onwards. Ofgem welcomes views on this issue. Ofgem continues to invite practical suggestions to better link capex incentives with outputs and take account of differences in capex forecasts across companies.**

2.50. While recognising the problem identified by Ofgem, DNOs were not in favour of the weakening of incentives for investment deferral. A number of alternative suggestions were made, ranging from capex monitoring and the use of Asset Management policies to the use of IIP as a basis for incentivising and rewarding outputs. Two DNOs proposed a sliding scale as a means of taking account of the differences in capex forecasts across companies, while another considered it natural that companies have differing capex projections as they are all at different stages in their investment cycles. One non-DNO considered that the proposal constituted a move away from incentive based regulation and therefore was against the proposal. Another respondent proposed giving DNOs a capex range for each year which would be reassessed as the year becomes closer and costs become more certain.

2.51. This issue is further considered in Chapter 3 of the main document.

Treatment of capex overspends

2.52. **Ofgem published an open letter on the gas distribution price controls which included its thoughts on the treatment of capex overspends – similar considerations apply to the DNOs.**

2.53. DNOs were sceptical about the feasibility of having clear and transparent tests for determining whether overspend is efficient and expressed concern over the additional uncertainty it imposed with respect to cost recovery.

Losses

2.54. **The target level of losses will be based on a proportion of units distributed and will be fixed for five years. During the period for which the target is fixed, the DNO will be exposed to the aggregate effect of the changes in recorded losses.**

2.55. Respondents did not object to the general principle of a fixed losses target, there were numerous comments in relation to how the mechanics of the calculation would work and its interaction with other incentives, e.g. DG.

2.56. **Where expenditure to reduce losses is efficient, it will be allowed in the RAV after five years.**

2.57. Respondents stated that further clarity was needed with respect to the criteria for assessing the efficiency of losses expenditure, and that the losses incentive rate needed to be revised upwards in order to merit investment in losses reducing equipment.

2.58. **Ofgem proposes that reported losses should simply reflect the difference between the estimated volume of electricity entering and exiting the distribution system.**

2.59. This proposal to simplify the system was generally welcomed.

2.60. **Several DNOs have expressed concern about the potential impact of large and/or multiple generation schemes locating or clustering in remote locations. Ofgem considers that some form of limited protection is appropriate. Ofgem intends to make an adjustment to the level of reported losses to reflect the impact of distributed generation with a loss adjustment factor (LAF) below a minimum level which should be set to 0.99.**

2.61. DNOs welcomed Ofgem's recognition of the issues surrounding the interaction of DG with losses, but considered that the limited protection being proposed would undermine the DG incentive mechanism. They also identified issues in relation to the connection of DG at LV and HV and that the "LAF floor" proposal would not work in SHEPD's area. One other respondent suggested that the distributed generators should be charged for the losses that they cause.

2.62. **Several DNOs have noted that it will be necessary to consider transitional arrangements in view of the changes proposed to the form and structure of the incentive.**

2.63. Two DNOs advocated a consultation on the transitional arrangements but one other considered that a transitional phase was unnecessary and would delay loss-reducing investments.

Price control for metering services

2.64. **The December document indicated that Ofgem was minded to introduce price caps for the provision of 'basic' domestic meters and non discrimination provisions in relation to other MAP activities. Responses to the December document were broadly supportive of this approach and Ofgem indicated it was intending to continue with this approach.**

2.65. **The December document suggested using an average revenue cap for MOp activities. Some respondents to the document supported this approach whilst others suggested using a price control for certain activities and a non-discrimination provision to cover the rest of these activities. Ofgem indicated it was continuing to actively explore both of these options.**

2.66. Some DNOs have suggested that a charging methodology would be sufficient to protect the interests of purchasers of metering services without the need for metering price controls. Ofgem has not ruled out this option.

MAP – Non Discrimination Provision

2.67. **In the March document Ofgem indicated that it intended to introduce price caps on domestic MAP. Ofgem also indicated that its continued intention to implement a non discrimination provision in relation to non half hourly meters.**

2.68. Two DNOs indicated a preference for approaches other than a price cap. However a number of respondents supported a price cap on MAP.

2.69. One DNO opposed using a charging methodology as a non discrimination provision.

2.70. One DNO wanted prepayment meters to continue to be treated as an excluded service.

MOp

2.71. **In the March document Ofgem indicated that it intended to apply an average revenue cap to MOp. Ofgem also indicated that it would be conducting regression analysis to consider options for different revenue drivers.**

2.72. Two DNOs wanted a price cap and non discrimination clauses to be applied to MOp. However, one felt that if an average revenue cap was adopted then it should be based on meter type and customer visits.

2.73. One DNO indicated that there was no need to price control or maintain residual service obligation on MOp at all. Another supported this but indicated that if a price control was warranted it should be on new installations with non discrimination provisions.

2.74. One DNO supported an average revenue control with customer type as the driver.

Basic metering services

2.75. **Ofgem indicated a number of alternative methods for defining a basic metering service in the March consultation document.**

2.76. One DNO supported using a functional definition for MOp and a technical definition for MAP as a technical definition would allow for the 3 different prepayment technologies in use. This technical approach to MAP was supported by a further DNO.

2.77. One DNO indicated that Ofgem should not specify a type of prepayment technology when defining basic as it will stifle competition.

2.78. One DNO stated that the definition of basic service needs to include the scope of that service.

Stranding

2.79. A number of DNOs also included comments in relation to stranding in their responses to the consultation document.

2.80. Two indicated that Ofgem must allow the recovery of stranded metering costs in the distribution price control. Another indicated that where services are bought through arms length commercial tendering the DNO should be allowed to recover full costs. A further DNO indicated that DNOs should be able to recover all costs both OPEX and CAPEX.

2.81. One DNO expressed concern in relation to the fact that Ofgem had yet to recognise DNOs concerns about stranding of assets and operating costs.

Metering RIA

Risk and unintended consequences

2.82. One DNO indicated that DNOs should have certainty that as they lose market share they will not have to ramp up services if the supplier chooses to return to the DNO.

2.83. One DNO rejected the suggestion that DNOs ability to win out of area contracts should be taken into account when determining the price control.

2.84. One DNO indicated that they were concerned that Ofgem's current proposed approach will result in stranded assets for DNOs. Another DNO indicated that the price control must take stranding into account as well as any costs incurred in meeting past and future obligations.

Costs and benefits

2.85. DNO metering activities will suffer diseconomies of scale as fixed costs are recovered over reduced work volumes.

2.86. A supplier who swaps away from the incumbent will receive a price benefit because the new meter service provider does not have the inherited costs of the DNO.

Competition

2.87. One DNO argued that price controls and licence obligations should be removed as there are no barriers to entry. Another argued that the existence of licence obligations will allow the continuation of the status quo in the metering market.

2.88. Another DNO did not accept that the DNO is the dominant incumbent.

Distribution

2.89. One DNO indicated that the cap on the differential between domestic credit and prepayment meters is outdated and unworkable.

2.90. Another DNO argued that a capped differential between prepayment and domestic credit is inconsistent with introducing competition.

3. Quality of service and other outputs

Guaranteed and Overall Standards of Performance (GOSPs)

Supply restoration standard

3.1. Ofgem considers that the supply restoration standard (GS2) could be separated to cover normal and severe weather conditions – which will build on the interim arrangements introduced in 2003 following the storms in October 2002.

3.2. Most respondents supported the principle of dividing the supply restoration standard into two separate standards covering normal and severe weather events. However two DNOs had concerns with Ofgem's proposed approach for revising the interim arrangements for storm conditions.

3.3. A small number of respondents noted that the standards of performance must complement the licence conditions which set out the relevant design standards. These respondents argue that standards of performance should not be set so tight so as to require networks to perform to a higher standard than required under Engineering Recommendation P2/5.

Automatic payments

3.4. Ofgem considers that DNOs should pay out automatically where possible and proactively contact consumers in general to make them aware of their right to compensation under the guaranteed standards framework where there has been a breach.

3.5. There was a general consensus among respondents that it is possible for DNOs to be proactive in contacting consumers who may be due a payment under the supply restoration standard or the other guaranteed standards. Four DNOs supported the concept of semi-automatic payments for supply restoration, but only during normal weather conditions.

3.6. Some respondents noted that semi automatic payments would result in additional costs and risks, even for efficiently operated DNOs and that an efficient level of payments should therefore be funded through the price control. One argument for this higher level of cost pass through is that networks designed in accordance with P2/5 are, by design, expected to incur payments under the 18-hour standard.

3.7. A small number of respondents noted that the mechanism for payments to consumers under the standards of performance framework can cause delay in consumers receiving payments and that improvement in the flow of consumer details would improve the service to consumers.

3.8. DNOs were generally of the view that it is not appropriate to introduce a mechanism that imposes an equivalent reduction in price control revenues when companies do not make appropriate payments under the 18-hour restoration. Two respondents, including one DNO, were supportive of the introduction of such a mechanism.

Compensation for business consumers

3.9. Ofgem considers it would be inappropriate to differentiate between domestic and lower voltage connected business consumers. As such, the compensation payments and timeframes for restoration will remain the same for these two groups of consumers

3.10. The DNOs who commented on this topic welcomed Ofgem's confirmation that it would be inappropriate to differentiate between domestic and business customers connected at lower voltage. energywatch was disappointed that LV connected business consumers are not going to receive higher levels of compensation given that they generally use more units and pay more for the service they receive.

3.11. The treatment of HV and above connected consumers should be considered in the light of the willingness to pay survey.

3.12. There was broad consensus among DNOs that large commercial consumers connected to the high voltage networks have the ability to choose the security of supply in their connection arrangements, and therefore have an opportunity to

mitigate the risk of supply interruptions through these agreements. DNOs generally considered that it was inappropriate to make large payments to HV consumers who have chosen less secure connection arrangements. energywatch set out in its responses that willingness to pay should not be the only consideration in relation to improvements in quality of supply. Together with another respondent, they noted that the compensation regime should be more closely related to charges.

Priority Service Consumers

3.13. Ofgem does not consider that the most effective approach would be to introduce a new standard of performance focused on vulnerable consumers.

3.14. Six respondents expressed support for Ofgem's view that the introduction of a standard of performance for vulnerable consumers would not be the most effective approach to improving the services provided to these consumers. However, one DNO noted that there was some merit in establishing a dedicated contact line for priority service consumers in to help meet its obligations in respect of these consumers.

3.15. A common theme among respondents was that it is important to ensure that the priority service registers are of manageable size, with a clear definition, limited to those consumers who are medically dependent on electricity.

The role of the overall standards of performance

3.16. Respondents generally supported the proposal to discontinue the overall standards and, where appropriate, introduce similar measures to be reported under the RIGs.

Reviewing IIP

Provision of disaggregated interruptions data

3.17. Ofgem proposes to modify the RIGs to include disaggregated interruptions data. Ofgem does not propose to introduce performance targets in respect of these measures at this review.

3.18. The majority of respondents supported the use of disaggregated performance data by HV circuit for comparing quality of supply performance. However, a number of DNOs believed it was inappropriate to use this information to set quality of supply targets. One respondent noted that the disaggregation process developed by Ofgem has not been shown to be robust over time. Another DNO believes that the disaggregation work is incomplete and hence it does not support the benchmarks as currently proposed.

3.19. One respondent suggested that there would be significant additional costs relating to the new reporting requirements and they should therefore be accompanied by appropriate funding.

Worst served consumers

3.20. Ofgem proposes to modify the RIGs to introduce a new requirement for reporting the number of consumers experiencing particular frequencies of interruptions each year. Ofgem does not intend to introduce performance targets in respect of these measures at this review.

3.21. All the DNOs were supportive of HV interruptions being the most appropriate measure of performance experienced by worst served consumers. One DNO noted that a similar measure to that currently proposed could be included to cover the number of consumers who have received a particular frequency of interruptions over a five year period.

Form of incentive scheme

3.22. Ofgem proposes to retain the incentive scheme for the number and duration of interruptions but move to annual rewards and penalties. Subject to the proposals on network resilience, severe weather will be excluded.

3.23. There was general support for Ofgem's proposal to move to a scheme with annual rewards and penalties and no deadbands or rolling averages. The DNOs consider that the rewards and penalties should be symmetric with the full impact of exceptional events excluded. However, if an asymmetrical scheme is finally chosen, DNOs consider that there should be additional compensation for annual variability. Another respondent proposed extending the scheme to the volume of energy not supplied.

3.24. Four DNOs suggested annual adjustments to allowed revenue rather than one adjustment at the end of DPCR4 as this would improve cash flow, would enable the adjustments to be passed directly to consumers and would have stronger incentive properties than a five yearly settlement period.

3.25. Three DNOs supported rolling up financial rewards and penalties as this would smooth some of the risk of annual variability experienced by all DNOs. One DNO was concerned that annual settlement could set unrealistic consumer perceptions and expectations with respect to the DNOs' control over network performance.

Weighting of interruptions

3.26. Ofgem proposes to establish weightings taking account of the results of the consumer survey.

3.27. None of the DNO supports the proposal to introduce different weightings for planned and unplanned interruptions. With existing weightings, DNOs are incentivised to consider the most efficient approach for improving consumer service, whether this involved reducing planned or unplanned interruptions. If the value of unplanned interruptions is reduced in the DPCR4 incentive scheme, companies will need to re-analyse the costs/benefits of interruption avoidance measures (e.g. the provision of mobile generators and live line/hot glove working). This could result in some of these measures becoming uneconomic and in consumers experiencing a worsening service.

3.28. One DNO advocated an alternative approach of excluding planned interruptions from quality of service incentives, while two other DNOs put forward a proposal to make allowances within the targets for proposed investment programmes.

3.29. Two DNO felt that whilst consumers may value planned and unplanned interruptions differently, applying different weightings is an unnecessary distortion.

Audit inaccuracy

3.30. Ofgem proposes that in the next price control period, performance data should be adjusted for any inaccuracies identified by the audits.

3.31. Half the DNOs support a streamlined audit process with the option to move to self audit in the longer term. Two DNO felt that there are still inconsistencies in the audit process that need to be driven out and therefore the existing audit process should be retained in the short term. Four DNOs felt that the self audit could be followed by an annual external audit of a randomly selected subset of incidents.

3.32. One DNO and energywatch proposed that there should be random audits along the lines of the current audit process, from the outset. Another respondent considered that this approach would have a higher regulatory burden than Ofgem carrying out streamlined audits for all DNOs.

3.33. All the DNOs are against using the samples to adjust the data back to the '100%' accuracy level. Four DNOs disagree with the proposal to adjust reported performance in line with the results of the sample audit as the audit sample is designed to reflect the accuracy of the overall data set only within certain confidence limits. One DNO proposed that Ofgem consider adjusting companies who fail by the difference between their own accuracy level and average accuracy for the companies who have met the reporting requirements. Two respondents proposed that a tightening of the accuracy requirement may be more appropriate.

Target Setting

3.34. Two DNOs support the process of disaggregation, although they believe the process is not robust enough to generate benchmarks as the process does not capture all of the inherent and inherited differences that exist in distribution networks.

3.35. A DNO also noted that it is uneconomic for other companies to replicate the volume of high voltage unit-protected circuits that SP Manweb and LPN have due to historic factors. It therefore believes it is inappropriate to include the performance of these two companies in setting the benchmarks that other companies are to achieve.

3.36. Another DNO noted that the IIP targets will need to take into account increases in planned interruptions as these will be necessary to undertake greater replacement work in the next price control period.

Treatment of planned interruptions for the final year of DPCR3

3.37. Ofgem proposes that DNOs should be allowed to roll forward up to 2 planned CIs and 3 planned CMLs from 2004/2005 to 2005/6.

3.38. Of the DNOs that responded on this matter, three opposed the proposal for a number of reasons including the belief that it is a dilution of the incentive mechanism and that DNOs do not know what their targets are for 2005/06 and hence the effect of rolling forward any CIs and CMLs. British Gas Trading also opposed the proposal in the absence of any evidence to substantiate the risk identified.

3.39. Two DNOs considered that it is a useful amendment to IIP for the current price control period to roll forward CIs and CMLs from 2004/05 to 2005/06 to mitigate any incentive to defer planned work in 2004/05. One DNO however proposed more stringent criteria for those DNOs who would be eligible to take part in the scheme.

Frontier performance

3.40. Those companies that are currently best performers on quality relative to the disaggregated benchmarks will be eligible to participate in the reward mechanism of the current IIP arrangements whether or not they meet both their targets for the number and duration of interruptions in 2004/05.

3.41. Three DNOs supported the proposal to modify the rules of the 2004/05 incentive mechanism to allow frontier performing companies in terms of quality relative to the disaggregated benchmark, to participate in the reward mechanism whether or not they achieve both their CI and CML targets.

3.42. One DNO was strongly against this additional reward as they viewed it as a re-opening the current price control and felt it would not have any effect on DNO incentives or behaviour. It was also noted by one DNO that additional research showed that the factors used in the disaggregation process only accounted for 25% of the variation in performance.

3.43. One DNO noted that the process of using benchmark performance requires as a pre-requisite both a clear definition of what is meant by "frontier" together with an equitable methodology of establishing the so prescribed frontier. Another DNO felt that the best performing companies should be identified by comparing each company's actual performance with their benchmarked performance and then ranking relative performance.

Network Resilience

Severe weather standard

3.44. Ofgem proposes to strengthen DNOs' incentive to restore consumers' supplies promptly following a severe weather event by refining the interim arrangements.

3.45. Two DNOs agree with the severe weather guaranteed standard and are supportive of the tiered approach outlined for the interim arrangements but consider that a great deal more work is required on the restoration standard applicable under extreme weather conditions. Further progress needs to be made before a fair combination of times, band size and the levels of funding can be determined. Also the interdependencies between the definitions of severe weather events, the IIP exclusion criteria and the trigger periods for consumer compensation payments need to be aligned in order to provide a complimentary suite of incentives. A DNO noted that the proposed thresholds do not yet prevent the risk of multiple jeopardy in relation to storm performance as a DNO could still be penalised under guaranteed standards and the IIP.

3.46. Two DNOs do not support the proposed enhancements to the existing interim storm compensation regime. They consider that public scrutiny, company reputation and the current financial exposure to GS2 and the 'Interim Arrangements' already provide companies with very strong incentives and no further incentives are required. Another DNO believes Ofgem should give the interim arrangements a chance to prove themselves before considering whether they should be modified.

3.47. It was noted that the present 'severe weather' exclusion clause in EGS2 allows for variable start time but the fixed times proposed by Ofgem for a new severe weather standard, based only on the number of consumers affected, do not.

Severe weather qualification criteria

3.48. Three DNOs believe that it may be better to define bands on exceptionality (the number of faults) rather than materiality (number of consumers affected) as it is the number of faults that determines how long it will take to restore all consumers. A DNO that invested in network automation, remote control and automation to improve consumer service and to gain rewards under IIP, would (perversely) be less likely to meet any materiality threshold for a given level of storm damage given the existing 'gate' scenarios.

3.49. A few DNOs believe it would be more appropriate to link qualification criteria for both storms and IIP with the events that triggered the interruptions. For example, if a DNO exceeds the proposed materiality thresholds following adverse weather, then any DNO which experienced the same conditions should be treated in the same way. This would ensure that a DNO whose network was more robust or which had superior restoration procedures, would still benefit from the IIP exemptions and face the same trigger periods for customer compensation.

Exposure

3.50. Many DNOs are concerned that Ofgem's proposals will significantly increase the exposure of companies to compensation payments particularly those that relate to factors, such as severe weather, over which companies have no control. It was their view that to limit such exposure, it is important to set caps for DNOs that limit the risk to a reasonable level with four DNOs advocating that the existing interim level of capping of financial exposure should be maintained.

3.51. One DNO proposed that a proportion of the compensation payments should be a pass through cost and it would be appropriate to use a sliding scale cost recovery profile, while another felt it is inappropriate for companies to bear any significant proportion of the cost of compensation payments as companies have not been funded to construct networks that are resilient to severe weather

events. One DNO observed that they would also require a much greater degree of pass-through for an enduring storm compensation arrangement. In particular, any scheme must ensure that an averagely efficient DNO is neutral to consumer compensation in an "average" year.

Incentives for telephone response

Survey sample

3.52. Ofgem proposes the survey will be expanded to include consumers who have their calls answered by an automated message in the next price control period.

3.53. Six DNOs and energywatch supported the proposal to increase the scope of the customer survey to include consumers whose call was answered by an automated message. They argued that this would give a fairer representation of consumer satisfaction with the quality of telephone response received. However, four DNOs referred to the difficulties with the practical development and implementation of this, particularly the technical difficulties of obtaining the details of consumers who have been answered by a message.

Combining quality and speed of telephone response

3.54. Three DNOs were broadly supportive of the proposal to assess satisfaction with speed of telephone response by means of an additional question in the consumer survey, and supported Ofgem's trial in the 2004/05 year. One DNO noted that this would mean that this output is measured based on perceptions and would not be an objective measure. Conversely, another DNO suggested that if the outputs were combined, it would be appropriate to cease reporting the speed of telephone response statistics required under the existing version of the RIGs. A further DNO considered it was inappropriate to combine the speed of answering and quality of service incentives.

Survey questions

3.55. One DNO supported the suggestion that it might be possible to combine the 'politeness' and 'willingness to help' assessed measures into an overall helpfulness question. Doing this would potentially remove an element of

subjectivity from the survey. Another respondent noted that in developing the survey, Ofgem should ensure consistency with the existing survey.

Form of the incentive scheme

3.56. A small number of respondents suggested that as DNOs' scores have converged to a point where consumers are generally "satisfied" with the quality of telephone response, there is more value in moving to an absolute performance targets that reward improvements in DNOs' own performance. One DNO advocated an absolute scheme with a common minimum level of performance below which incentives should apply. A number of other respondents set out that there may not be a need to penalise the lower scoring companies provided certain minimum standards were met.

3.57. Two DNOs did not consider it was appropriate to move to an absolute scheme given the suggestion to amend the survey questions, as this would mean that any targets for performance would be based on historic performance against different measures.

3.58. One DNO suggested the quality of telephone response incentive should be discontinued, based on the convergence of DNO performance in this area. It suggested that consumer satisfaction is at a level that is superior to other industries and other countries.

Environmental outputs

3.59. Ofgem proposes to introduce reporting requirements on a specific range of environmental output measures, but Ofgem does not propose to introduce financial incentives on any of these output measures over the next price control.

3.60. Four DNOs agree with Ofgem's proposal to begin to introduce a framework for the reporting of certain environmental outputs. Two of these supported Ofgem's proposal not to introduce financial incentives on any of these output measures.

3.61. Two DNOs felt that the introduction of monitoring for environmental outputs of DNO activities without any supporting environmental objectives seems inappropriate and will involve duplication of effort.

3.62. One other respondent welcomed the introduction of environmental measures but would like to see outputs linked to appropriate incentives and is disappointed Ofgem does not intend to introduce financial incentives in this area. It considers that there needs to be more focus on landscape and amenity issues within the reporting requirements.

General discretionary reward

3.63. Ofgem considers it may be appropriate to introduce a separately assessed discrete reward for service performance in other aspects of how DNOs address the needs of their consumers. Ofgem would welcome views on this.

3.64. DNOs generally accepted that there are many areas of customer service that are not presently measured under the IIP arrangements, and the majority would therefore welcome a discretionary process that recognises these areas. One DNO was concerned that such a scheme should not reward companies for merely achieving its licence conditions.

3.65. DNOs also generally supported the opportunity to earn additional rewards under the scheme but set out that the mechanism and the measurement criteria must be defined in advance if performance is to be measured objectively.

3.66. Other respondents, one of whom proposed a symmetric scheme, also supported a discretionary reward as it encourages companies to think more widely than the explicit measures and incentives introduced and incentivised under the IIP framework.

3.67. One DNO suggested possible criteria would include number of complaints per 10,000 consumers and adoption of customer service best practice, in particular to consumers on the priority register and communication with consumers more widely, Ofgem, energywatch, the media and other bodies during exceptional events. Another DNO suggested that perhaps the reward could be shared by dividing it across a number of categories of consumer service.

3.68. One DNO was concerned that a discretionary reward would be too subjective and does not believe that there is any robust means for Ofgem to objectively assess performance in these areas across DNOs.

4. Distributed generation, innovation funding and registered power zones

Incentive framework for distributed generation

4.1. Ofgem proposes to adopt an 80 per cent pass-through rate for the incentive scheme. In the December document this resulted in an incentive rate of £1.5/kW/yr associated with the 80% pass-through. Based on the views of its consultants, Ofgem's own work and the cost information reported by the DNOs, this figure appears appropriate for the majority of the DNOs.

4.2. Ofgem will set a floor to the rate of return on the overall portfolio of distributed generation connected in the next price control period, equal to the allowed cost of debt as specified by Ofgem in calculating the cost of capital. Ofgem also intends to cap the maximum rate of return on the overall portfolio of distributed generation connected in the next price control, to a level equal to two times the allowed cost of capital.

4.3. The 80% pass-through rate was supported by the DNOs, whereas the level of the incentive rate was felt to be too low by some. The issue that the majority of the DNOs remain concerned about was the application of the incentive rate only to the DG capacity that materialises and remains to be connected. Whilst welcoming the adoption of cap and floor to DNOs' return on DG costs, some suggested various adjustment to the values, generally to raise the cap and floor.

4.4. Some other respondents, which included bodies representing distributed generators' interests, considered that the incentives were over-generous to the DNOs.

The value of the incentive rate for Scottish Hydro-Electric

4.5. One DNO, Scottish Hydro-Electric, has been allowed a slightly higher incentive rate to reflect the higher than average costs identified by Ofgem's consultants for connecting distributed generation to its network.

4.6. The higher incentive rate for Scottish Hydro-Electric was welcomed by the DNO concerned. Two other DNOs agreed with the principle of the special treatment, but argued that if other DNOs incur efficient costs higher than originally forecast, they should also be given higher incentive rates. One further DNO wanted reassurance that the rates reflect genuine cost differences and another respondent saw that the higher rate could potentially deter DG development in that area.

O&M costs and the final incentive rate

4.7. The DNOs will be allowed £1/kW/yr to cover the O&M costs. This figure will be reviewed at the time of the next price control review in 2010. If it appears that costs have fallen Ofgem would expect to pass the benefits of this on to generators.

4.8. The proposed £1/kW/yr rate for O&M was supported by two DNO respondents, but opposed by some others. The latter suggested that more equitable a approach would be to: adopt a similar hybrid mechanism as for capex (80% pass-through plus incentive), apply the same methodology as in demand (capitalisation), or to increase the rate (2% per year general, or 1.5% for HV/LV connections). Another DNO suggested that adjustments, whether higher or lower, could be made after a future review. On the timing of application of the O&M rate, the transmission company and a number of DNOs pointed out that the incurrence of O&M costs could start before DG connects and continue after DG closes, therefore it would be inappropriate to remunerate such costs on the basis of the connected DG capacity.

Strategic investment

4.9. No additional allowance will be made for strategic investment.

4.10. One DNO respondent reiterated its support for the use of the hybrid mechanism for all shared and strategic network investment. However, three others continued to believe that special treatment should be given to advance strategic investment. Another respondent commented that speculative investment should not be encouraged.

'High cost' projects

4.11. There may be certain projects which, because they are of such unusually high cost, or have requirements significantly in excess of the DNOs' design standards cannot be incentivised under the main DG incentive scheme. In such circumstances, Ofgem would expect the generator seeking connection (and giving rise to the costs) to fund the required additional investment through connection charges.

4.12. Most DNOs welcomed the proposal of special treatment for projects of unusually high costs, but commented that the threshold should be lowered, and that projects of high total costs not just high unit costs should also be included. One DNO respondent, however, was against the perceived reverting back to deep connection charging.

Microgeneration

4.13. Views are invited on whether or not the DG incentive should apply to microgenerators (i.e. whether the capacity should attract the £/kW incentive payment).

4.14. The majority of DNOs and two other respondents believed that micro-generation should be included in the DG incentive arrangements. The remaining DNOs and another respondent suggested that given the higher uncertainty, costs for connecting micro-generation could be treated as load-related reinforcement and be secured in RAV, subject to a review after 2010.

Incentives for ongoing network access

4.15. Ofgem considers that an incentive such as the £0.002/kWh incentive suggested in the December document should be provided to focus DNOs on providing ongoing network access. Ofgem welcomes views on the practical application of this incentive.

4.16. Most DNOs continued to oppose the proposal of compensation for network unavailability. Some saw it deterring the development of active management which may involve the use of generation constraints, some believed that the DNOs and DG should be free to negotiate terms for access, some questioned the

potential inconsistency between treatments for demand and generation. If a compensation scheme was to go ahead, some DNOs suggested alternative approaches which would reward as well as penalise around a certain target availability level lower than 100% and which would limit the DNO's risks. Some reiterated the need for additional funding under such a scheme. The transmission company also suggested that the downside of the incentive scheme should be limited.

Modelling the incentive scheme

4.17. Comments from the DNOs showed support for adopting a RAV approach rather than an annuity approach for profiling the pass-through revenue, due to the perceived exposure to DG failure, and the potential complexity for operating two different approaches. They argued that the benefits from the annuity model towards GDUoS stability would be immaterial. The proposal of protecting the pass-through revenue by recovering it from demand when necessary was welcomed by the DNOs, but raised concern with another respondent. Further clarity was requested on a few detailed aspects.

Definitions and reporting

4.18. Ofgem expects, as a starting point, to base any definitions on those used in the DG-BPQ. Views are invited on reporting (including any audit) arrangements.

4.19. It was agreed widely that clear definition and robust reporting would be needed for the implementation of the DG incentives. Some DNOs suggested that the additional costs incurred on this should be allowed separately.

Registered Power Zones and Innovation Funding

4.20. Ofgem considers that the RIA gives confidence to proceed with the introduction of these new incentive mechanisms.

4.21. There was wide support for the RIA amongst respondents. One party said that it was the most well developed of the DPCR RIAs and made a "sound case" for the IFI and RPZ proposals.

Ofgem's proposals – Innovation Funding Incentive

4.22. Ofgem proposes that the R&D Intensity cap for IFI is 0.5% and that IFI funding will be on a use it or lose it basis.

4.23. A number of parties supported the proposed level of R&D Intensity. No alternative levels were proposed.

4.24. Ofgem proposes to maintain the profile of pass-through set out in the December document (which averages 80% over the price control period).

4.25. Amongst the DNO community, the majority of respondents argued for a higher level of pass-through. However, this was not a unanimous view and there was support for the Ofgem proposal.

4.26. Ofgem proposes that the IFI funding can be used to fund internal company expenditure but should be capped at 15% of the total IFI funding in each year.

4.27. There was support for the principle that internal costs should be allowable under the IFI scheme. However, there were different views as to the cap that should apply. Some respondents thought that the Ofgem proposal was acceptable, others that there should be some degree of flexibility and one respondent proposed that there should not be a cap.

4.28. IFI projects will be focused on the technical development of distribution networks (up to 132kV) to deliver value (i.e. – financial, supply quality, environmental, safety) to end consumers. Ofgem also proposes that any company that wishes to pursue IFI funded projects will have to produce and comply with a good practice guide for managing R&D projects.

4.29. The focus for IFI projects proposed by Ofgem was widely supported. No alternatives were proposed. There was also widespread support for the good practice guide although there were differences of view on its form and the benefits of a common document. A number of parties expressed interest in working with others to develop the guide but some expressed concern that this approach might diminish the value of the document.

4.30. Ofgem proposes that there should be open reporting of IFI activities as set out in the December document. Ofgem wishes to encourage momentum to be

maintained and would welcome views on putting in place interim arrangements to enable IFI projects to commence ahead of the start of the next price control period.

4.31. No objections to open reporting were raised and a number of parties thought that this was an essential part of the IFI scheme. A number of parties actively supported the introduction of the IFI before 1 April 2005.

Ofgem's proposals – Registered Power Zones

4.32. It is proposed that the cost of RPZ projects will be met by generators as a class within a DNO area in the same way as the DG incentive scheme.

4.33. There were a limited number of comments on this issue. Two respondents supported Ofgem's view but one expressed a general concern that DNOs were being too well rewarded for connecting DG.

4.34. Ofgem proposes that DG connection projects may be registered as RPZs at any time during the next price control period. Such projects will attract a 100% uplift of the £/kW element of the DG incentive scheme for a five year period commencing on the date of commissioning of the project. It is further proposed that this additional revenue that a DNO can claim for RPZ projects will be capped at £0.5m per DNO per year.

4.35. There was broad support for RPZs. However, a number of DNO respondents argued that the uplift in the £/kW element of the DG incentive did not adequately balance the higher risk profile that RPZs are expected to have. Examples of specific risks were provided and proposals were made to address this perceived imbalance. There were only two comments on the RPZ cap proposed by Ofgem. One party commented that it could restrict RPZ activity while the second party proposed that the cap should be an order of magnitude greater.

5. Assessing costs

Review of forecasts

5.1. DNOs welcome Ofgem's intention to take more account of company forecasts, although it should to be recognised that different assumptions have been used in compiling them. One DNO is of the view that the Quality of Supply case is of no value, and just a scenario to flex the base case. DNOs support the work to establish consistent and comparable data with which to assess efficiencies, but Ofgem should appreciate the difference between cost projections and the efficiency assessment process. One DNO commented that some DNOs have taken a different approach to risk and included some costs in the base case that other DNOs have included in the DNO case. That DNO also commented that the allowances set should assume the same levels of risk for each DNO and that any change from the current level should be reflected in the cost of capital or through another mechanism for dealing with uncertainty.

Normalisation of costs

5.2. DNOs recognise the difficulties of the cost normalisation process both from the companies and Ofgem's point of view, and believe there should be greater transparency in the process. A number of DNOs generally agree with the process although they still think that further work needs to be done and one in particular would prefer fault costs to be treated separately. One DNO saw the need for an external firm of accountants to resolve outstanding data inconsistencies. Another DNO said that Ofgem should examine how sensitive the normalised data is to different assumptions or particular data. Due to these difficulties DNOs favour the use of "average costs" rather than frontier costs in setting allowances.

5.3. One DNO commented that the normalised operating costs are too low to enable even an efficient company to cover costs so Ofgem needs to add back certain costs it has deducted for normalisation purposes. One DNO commented that the review of atypicals had focused on atypically high costs, and no adjustment had been made for atypically low costs. One DNO suggested that Ofgem

should only normalise for external atypicals as adjusting for internal atypicals is complicated by some companies working to overall annual budgets.

5.4. One DNO commented that there was no need for a detailed normalisation process, operating costs should be normalised for the 132kV network in Scotland, capitalisation policy differences and regional adjustments for SSE Hydro and LPN only. Allowances should be based on average costs plus an assumed standard percentage capitalisation of average faults less Ofgem's estimate of efficiency plus the cost of achieving these. One DNO suggested that the definition of what is opex and capex should be more prescriptive. Another suggested that the allocation between opex and capex is a question of funding.

Bottom Up modelling

5.5. Ofgem and PB Power's approach remains broadly unchanged from the December document. Initial analysis based on PBP's models will be published in the June Initial Proposals document.

5.6. Some DNOs are keen to receive copies of PB Power's modelling so that can understand the processes being used. One DNO was concerned that the detailed modelling could lead to a low benchmark for costs / activities below that attainable by any one company.

5.7. The results of Ofgem's bottom up modelling of tree cutting costs is shown in the main document. The bottom up modelling of the other repairs and maintenance costs has not yet produced robust results.

5.8. This issue is further considered in chapter 6 of the main document.

Top down analysis

5.9. Ofgem's broad approach to top-down analysis remains as set out in the December document – although detailed issues about how the analysis is undertaken will need to be considered in the coming months. The results from Ofgem's top down analysis will be published in the June initial proposals document.

5.10. DNOs favour the use of average benchmarking as this avoids the potential for normalisation errors and an average can be estimated with more certainty. One

DNO commented that Ofgem should not assume all differences between DNOs in the regression were down to inefficiencies and they should test for other explaining factors. A number of DNOs suggested that the analysis should include a measure of quality, so as not to reward for reducing quality of service. One DNO suggested that Ofgem should use a range of analysis to validate cost estimates, not set them, and the analysis should concentrate on 8 management groups. A number of DNOs wanted Ofgem to do a total cost analysis in addition to the analysis of opex and total faults. One DNO said there was no compelling case for future efficiencies by applying an ongoing efficiency improvement expectation to any derived benchmark. It was also argued that DNOs cannot be expected to pass on benefits from savings onto customers before they have been achieved.

5.11. It was also noted that the use of an upper quartile may have similar properties as the average of efficient companies are rewarded.

5.12. This issue is further considered in chapter 6 of the main document.

Mergers

5.13. The evidence from mergers within the British DNOs suggests that it is not necessary to adjust DNOs' costs for merger savings for the purposes of benchmarking. Ofgem will set out further thinking on the treatment of merged DNOs in the June Initial Proposals document.

5.14. Most DNOs agree that there is no need for any merger adjustment for the purpose of benchmarking. However one DNO commented that an adjustment would be required unless benchmarking is done on the basis of 8 merged groups. Some DNOs commented that Ofgem must ensure that merger benefits are retained for a full 5 years otherwise groups merged since June 2002 will be penalised. One DNO was concerned that Ofgem were now suggesting that many of the merger savings could be achieved via other corporate structures. One DNO suggested that net merger benefits could be factored into final allowances by adjusting allowance glide-paths rather than adjusting benchmarking models. One other respondent was disappointed that Ofgem had concluded that there was no need for a merger adjustment and said this was contrary to the rationale used in the past.

5.15. This issue is further considered in chapter 6 of the main document.

RAV Roll forward

5.16. Ofgem is reviewing the submissions from the DNOs and also the evidence provided by PKF (Ofgem's DPCR3 consultants) and expects to be in a position to say more about this issue in the June Initial Proposals document.

5.17. There were a number or comments in this area but no common themes. One DNO would like to see the initial thinking in this area before the June proposals. Another DNO had made several submissions and presentations in this area to Ofgem, but had not received a formal response. They reiterated that the costs of post fault asset replacement must be added to the RAV. One DNO was concerned that some DNOs were allowed to include fault costs in their RAV, but not all, as a result of DPCR3. They suggested a solution to this imbalance would be to retain the industry average proportion of fault costs within the RAV (RAV roll forward only).

Other

5.18. One DNO made a number of comments regarding fault costs. The significant boundary issue between post faults and other replacement capex should be resolved or fault cost should be removed from any comparative analysis. As fault costs are significant in relation to other controllable costs they should be modelled separately on a company specific basis using an assessment of efficient unit costs. Fault cost analysis should be done using appropriate costs drivers – overhead/underground mix, regional factors and asset age and normalised to exclude severe weather events. It was also argued that CEPA had overestimated the scope for further efficiency improvements.

6. Financial issues

Financial ring-fence

6.1. The March 2004 document proposed not to substantially strengthen the existing financial ring-fence. Instead, it proposed to clarify the existing arrangements by codifying a 'cash lock up' in all DNO licences.

Views of respondents

6.2. Only a few respondents commented on the 'cash lock up' proposal. It was argued that the proposal was reasonable but a number of respondents questioned the level of the trigger. One of the DNOs supported the proposed criteria for the cash lock up trigger but felt that it is disproportionate to take the lower of a split rating as a trigger and that this would be inconsistent with the licence obligation to maintain an investment grade rating, which refers to investment grade rating from a single agency. However, another respondent argued that the proposed trigger level might not be enforceable in a timely manner if a minimum investment grade rating is under threat. This respondent also argued that any consent for transactions needs to be public, so that all concerned parties can be aware of the DNO's situation.

6.3. One DNO argued that a formal 'cash lock up mechanism' is not necessary as current licence provisions are perfectly adequate. It was also argued that the price control settlement should be based well above the trigger level, e.g. A-credit rating.

Ofgem's view

6.4. Ofgem has considered the different arguments carefully. As set out in previous consultation documents, Ofgem is still of the view that a substantial strengthening of the existing financial ring-fencing arrangements is not necessary. However, Ofgem does consider that greater clarification on how it would enforce the existing financial ring-fencing arrangements is desirable.

6.5. In the December consultation document Ofgem proposed various options for the trigger which would make the cash lock up mechanism operative. Ofgem

recognises that pitching the trigger too high (for example at single A level) would involve a tightening of the existing arrangement. However, setting the trigger too low, would remove the automatic protection which the cash lock up mechanism is designed to provide. Ofgem is therefore of the view that its proposed trigger, as outlined in the March document, is most appropriate.

6.6. As indicated in the March document, Ofgem intends to implement a 'cash lock up' mechanism in all DNO licences. The work on developing the mechanism will now be taken forward as part of the licence modification process for implementing the revised price controls.

The cost of capital

The proposed range for the cost of capital

6.7. In the March 2004 document Ofgem proposed a range for the post-tax (real) cost of capital of 4.2% to 5.0%, which translates to a pre-tax, real cost of capital in the range of 6.0% to 7.2%. Ofgem also indicated that it would treat tax directly through the financial model rather than through the cost of capital and proposed a 'Vanilla' WACC in the range of 5.1% to 5.9% for financial modelling purposes.

Views of respondents

6.8. The majority of DNOs argued that Ofgem should adopt a cost of capital estimate at least at the top end of the range and several companies argued that in addition an allowance for embedded debt and/or issuance costs (debt and/or equity) should be made. It was also pointed out that Ofwat's floor cost of capital (5% post-tax real) is the top end of Ofgem's range and that electricity is inherently more risky than water, given that in water there is a framework for Interim Determinations which does not exist in electricity.

6.9. Several DNOs have argued that if Ofgem reduces the scope for outperformance, for example through a weakening of incentives or through setting tight cost allowances, this should be compensated for through the cost of capital. It was argued that what ultimately matters is not the regulatory cost of capital but the achievable return on capital which consists of the regulatory cost of capital and

the scope for outperformance. One company argued that the appropriate post-tax return for *efficient* companies is in the range of 6% to 7%, including around 100 basis points for outperformance.

6.10. Another (non-DNO) respondent argued that Ofgem's proposals to capitalise certain categories of operating costs and to reduce the incentive to defer capital expenditure will reduce the reward for out-performance and therefore the ability of companies to deliver returns to shareholders. It stressed that Ofgem should have regard to the discontinuity in incentives that it is introducing when setting the regulatory cost of capital going forward. It was argued that simply basing the cost of capital on recent market data, which reflects the past scope for out-performance, could result in Ofgem ending up in a similar situation to Ofwat at the last water review, which resulted in too low a cost of capital.

6.11. It was also argued that equity returns for continental utilities are significant double digit returns (circa 13%-14%), whereas Ofgem's range is half of this. It was argued that this raises significant issues for DNOs competing for funding in the world-wide capital markets.

Ofgem's view

6.12. The cost of capital is one of the key inputs in the price control. It should therefore be assessed in a risk and return framework and hence the overall regulatory regime should be taken into account. For example, the Smithers report on Betas[2] shows that equity betas for UK electricity companies were relatively high (reflecting a high(er) level of risk and hence potentially higher return), however, after this initial period there has been a sustained decline in equity betas (reflecting a lower level of perceived risk).

6.13. A possible explanation put forward by the Smithers report is that "in the early years a number of these companies were relatively new, and their properties were therefore relatively unknown; whereas by the later sample periods, they had become more familiar to the markets, and therefore their betas began to settle down". Therefore, a direct comparison of the regulatory cost of capital for

[2] Wright, S. (Birkbeck College) and Smithers & Co (March, 2004), Beta Estimates for: Scottish Power, Scottish & Southern Energy, Viridian Group, Centrica, International Power, National Grid Transco, United Utilities, Kelda Group, Severn Trent, p.5. This study is available on the Ofgem website.

UK DNOs with the regulatory cost of capital of continental utilities or the water sector is not appropriate.

6.14. Given the investment focus of this review it is important that the DNOs are able to attract sufficient capital (i.e. debt and/or equity). Arguably, compared with many other investment opportunities, investment in UK network utilities such as electricity distribution companies might be regarded as relatively low risk given the monopoly positions of the companies and the resulting stable customer base and hence stable cash flows and the generally well-understood and stable regulatory environment. The regulatory regime is designed to ensure that the overall package is balanced. Therefore, investors in efficient firms should be able to earn an appropriate return on capital given the risk profile of the investment and hence the firms should be able to attract sufficient capital in global capital markets.

Methodology

The expected cost of equity

6.15. In the March Cost of Capital appendix Ofgem adopted a CAPM[3] approach to estimate the cost of equity in combination with an aggregate return on equity (ROE) approach for the top end of the range. Ofgem also applied the DGM[4] model as a cross-check.

Views of respondents

6.16. Respondents welcomed Ofgem's approach to adopting a consistent method for setting the allowed cost of capital and the transparency of the considered evidence at arriving at the key parameters.

6.17. However, it was pointed out that CAPM might be biased by short-term market conditions and that the results should therefore be cross-checked using other methods.

6.18. It was also pointed out that a CAPM approach might underestimate the cost of equity because it ignores the negative 'skewing' caused by incentive regimes

[3] Capital Asset Pricing Model
[4] Dividend Growth Model

such as IIP. NERA[5] argued that CAPM does not fully account for downside asymmetric risk, for example the risk of 'clawing back' of returns which are deemed to be 'excessive'.

Ofgem's view

6.19. The cost of equity is a key component of the cost of capital especially given the investment focus of this review.

6.20. The empirical weaknesses of CAPM have been well documented, however, alternative models have their own weaknesses and no clear successor to CAPM has emerged.

6.21. Ofgem has not solely relied on CAPM in estimating the cost of equity but also taken into account evidence of an aggregate ROE approach whilst applying DGM as a cross-check.

The inputs to the cost of equity

CAPM approach

6.22. In the CAPM approach the cost of equity is estimated as the sum of the expected risk free rate and the product of the company's expected equity beta and prospective ERP.

The expected risk-free rate

6.23. In the March document Ofgem presented a range for the risk-free rate of 2.25% to 3.00%. This range reflected the considerable uncertainty surrounding the expected risk-free rate and the sensitivity of the cost of capital to this parameter.

Views of respondents

6.24. Most DNOs have argued that the bottom end of Ofgem's range is too low, i.e. lower than the bottom set by the Competition Commission. It was also pointed

[5] n/e/r/a (2004), UK Electricity Distribution Cost of Capital, A Report for EDF Energy, March 2004

out that NERA evidence of a range of American and French index linked bonds points to a risk-free rate of 2.9%.

Ofgem's view

6.25. In the March 2004 appendix on the cost of capital[6], Ofgem proposed a range for the expected risk-free rate of 2.25% to 3.00%. This relatively wide range reflects the considerable uncertainty surrounding the expected risk-free rate as well as the fact that the cost of capital is very sensitive to the risk-free rate.

6.26. In May 2004 OXERA[7] presented some sensitivity analysis showing that of the relevant inputs to the cost of capital, the cost of capital is most sensitive to the risk-free rate.

6.27. At present, real UK gilt yields are still around 2%. This seems to provide justification for the bottom end of the range. However, as pointed out in the March Cost of Capital Appendix, there are various factors, potentially on the demand as well as the supply side, which could result in a higher expected risk-free rate for DPCR4.

6.28. Arguably, the risk-free rate should be seen in combination with the ERP. Hence, it might be more appropriate to view a risk-free rate towards the bottom end of the range in the context of an ERP at the top-end of the range.

6.29. NERA[8] based its estimate of the risk-free rate on a portfolio consisting of 3 French and 2 US index linked bonds. However, this portfolio seems biased towards long-term maturities and hence should be assessed in the context of duration, volatility as well as exchange rate risk. In Ofgem's view it therefore does not seem appropriate to base the expected risk-free rate on such a portfolio.

6.30. Ofgem considers that its range for the risk-free rate as presented in the March document of 2.25% to 3.00% remains appropriate.

[6] Ofgem (March 2004), Background information on the cost of capital, 62a/04
[7] OXERA (May 2004), "Decisions under Uncertainty" in *The Utilities Journal*, p.16
[8] n/e/r/a (March 2004), UK Electricity Distribution Cost of Capital, A Report for EDF Energy

The Equity Risk Premium (ERP)

6.31. In the March document Ofgem adopted a range for the ERP of 2.5% to 4.5%. This range is in line with the most recent Competition Commission decisions and based on long-term historical data.

Views of respondents

6.32. It was pointed out that a different interpretation of the evidence would arrive at higher numbers. Several DNOs argued that Ofgem should adopt an ERP at the top or above its range. It was also argued that given that DNOs operate in global capital markets, a global ERP might be more appropriate and that Dimson, Marsh and Staunton conclude that the global arithmetic prospective ERP is 5%.

6.33. The NERA report[9] assumes an ERP of 5%. NERA recognises that this is towards the top end of the ERP based on UK regulatory precedent, but argues that it is towards the bottom end of the ERP based on long-run international historical data.

6.34. In its report for ENA, OXERA[10] presents several ERP estimates based on DGM.

Table 1 OXERA ERP estimates based on DGM approach

ERP estimate based on:	2003	Latest
FTSE All-share	3.80 - 4.05	3.43 – 3.68
FTSE 100	3.86 – 4.11	3.55 – 3.80
FTSE 30	4.48 – 4.73	4.00 – 4.25
ERP average	4.05 – 4.30	3.66 – 3.91

Ofgem's view

6.35. The ERP is not an observable variable. A different interpretation of the data could therefore result in a different range for the ERP, especially considering that the ERP estimate tends to be very sensitive to the selected time-frame and averaging methodology (i.e. geometric or arithmetic).

[9] n/e/r/a (2004), UK Electricity Distribution Cost of Capital, A Report for EDF Energy, March 2004
[10] OXERA (2004), Energy Networks Association - Cost of Capital Update, Final Report, March 2004

6.36. An alternative approach to obtain an estimate of the prospective ERP is through surveys. However, this also raises a range of robustness issues, as set out in the March Cost of Capital Appendix.

6.37. Given the difficulty in establishing the 'true' value of the prospective ERP, it is important to assess the ERP in combination with the risk-free rate. As pointed out in the Smithers & Co study[11] in situations where there is considerable uncertainty surrounding the inputs in the cost of equity an aggregate return on equity approach might be more appropriate (depending on the risk profile compared with that of an 'average' company in the market).

6.38. Given the above, and previous analysis as set out in the March Cost of Capital Appendix, Ofgem considers its range for the ERP appropriate, although given current market volatility, probably more weight should be given to the high end of this range rather than the low end.

Equity beta and asset beta

6.39. In its March Cost of Capital Appendix Ofgem presented a range for equity beta of 0.6 to 1.0.

View of respondents

6.40. Several companies argued that the DNO equity beta is 1 at a 50% gearing level and that a higher gearing assumption would therefore result in a higher equity beta.

6.41. It was also assumed that an asset beta of 0.5 would imply an equity beta of 1 at 50% gearing and an equity beta of 1.25 at 60% gearing.

6.42. As pointed out by OXERA[12], observed equity betas at group level have continued to fall, in spite of the fact that gearing levels for most utilities have increased over time and the regulatory framework and commercial environment have remained fairly constant. OXERA adopts an equity beta of 1 in its cost of capital calculations for the DNOs.

[11] Smithers & Co (2003), A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the UK

[12] OXERA (2004), Energy Networks Association - Cost of Capital Update, Final Report, March 2004, p.13,14

6.43. NERA applies an equity beta of 1.28 in its report for EDF. This figure is based on an asset beta of 0.5 and a gearing assumption of 60%.

Ofgem's view

6.44. The observed equity betas at group level reflect the risk profile of the group as a whole. The risk profile at licensee level is likely to be different and given a diverse range of activities of the quoted groups in the electricity sector, the distribution activities might be expected to be less risky, this would suggest a lower equity beta for the licensee compared with its parent company.

6.45. Several DNOs argued that Ofgem should adopt an asset beta approach and re-lever the asset beta to reflect the 60% gearing assumption.

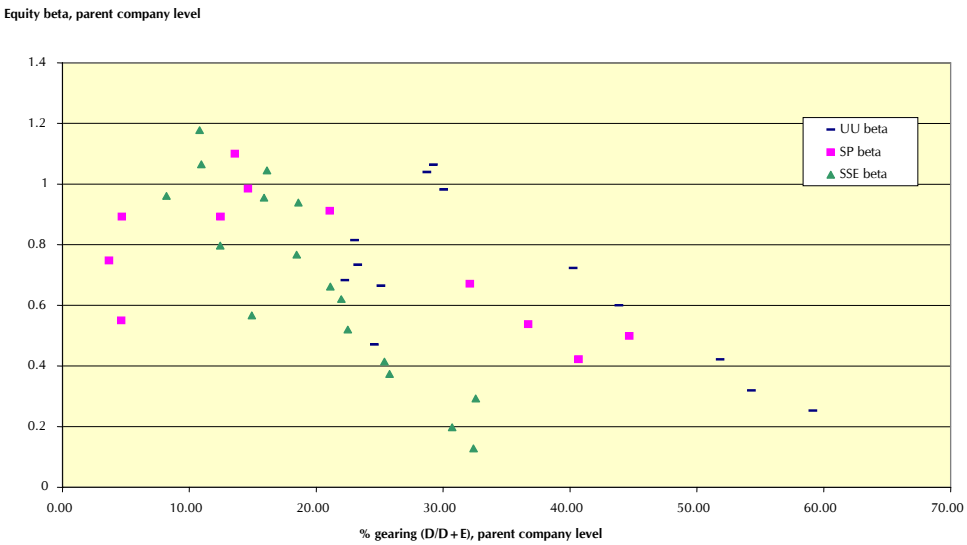
6.46. However, given the lack of 'pure play' companies, such an approach would require a robust beta decomposition. As pointed out in the March Cost of Capital Appendix such an exercise is fraught with difficulties and unlikely to produce a robust figure.

6.47. To put the equity beta for EDF proposed by NERA in context, it would suggest that equity investors in EDF face a similar level of risk to equity investors in a firm like Lloyds TSB (1.27), and face more risk than equity investors in Cable and Wireless (1.22), Easyjet (1.19), First Choice (1.17), Last Minute.com (1.14)[13].

6.48. One of the main problems with a linear transformation as often used in an asset beta approach is that it assumes a simple linear relationship between risk and gearing. However, as Figure 1 shows and as also has been observed by OXERA, there are many instances where as gearing increases, equity beta decreases. Given that equity betas reflect non-diversifiable risk and hence are influenced by a range of factors, of which gearing is only one factor, this might not be altogether surprising

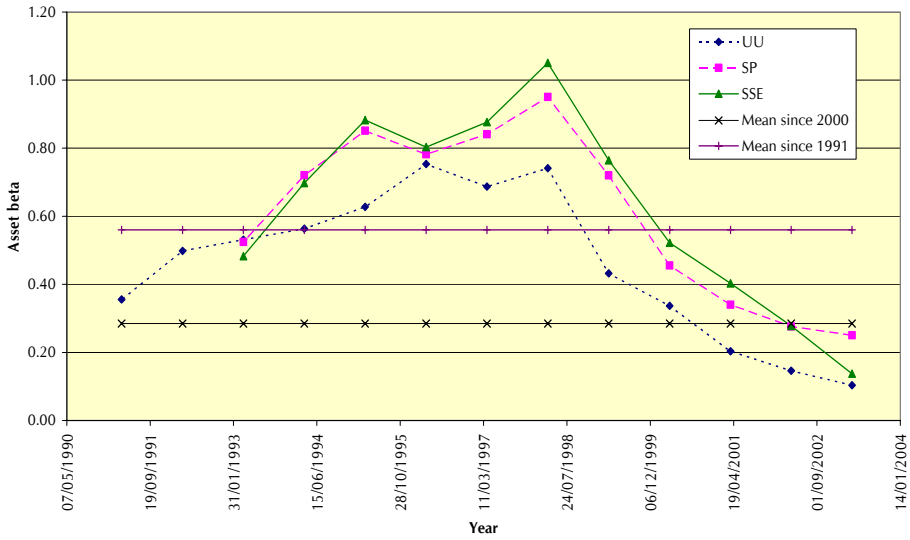
Figure 1 The relationship between equity beta and gearing at parent company level

[13] London Business School (2004), Risk Measurement Service, Vol 26 No 1 January – March 2004



6.49. Figure 2 presents asset betas over the period 1990-2003. As demonstrated in the Wright and Smithers & Co report, one of the main problems in beta estimation is evidence of structural breaks in the data set. The same problem applies to asset betas, given that asset betas are derived from observable equity betas. However, this figure does demonstrate that asset betas have declined over time and might have become more stable in recent years. Given the high degree of parameter instability it is not appropriate to use an average asset beta over the whole sample period. However, it is also questionable how robust a cost of capital based on an average asset beta over the more recent period (2000 - present) would be, given the relatively short-time period.

Figure 2 Asset betas over time



6.50. The next table shows equity betas which have been obtained by re-levering asset betas for the cost of capital gearing assumption. The assumed gearing assumption for re-levering is 60% which is consistent with the approach adopted in the financial modelling and discussed in the next section. The following formula has been used to obtain asset betas from observed equity betas (at parent company level):

$$\beta_{asset} = \frac{\beta_{equity}}{1 + debt/equity}$$

6.51. In order to re-lever the asset betas to obtain an equity beta at licensee level the following formula has been applied:

$$\beta_{equity} = \beta_{asset} \times (1 + (debt/equity))$$

Table 2 Equity betas obtained by re-levering asset betas

Company	Scottish Power				Scottish & Southern Energy				United Utilities			
Year	2003	2002	2001	2000	2003	2002	2001	2000	2003	2002	2001	2000
LBS beta*	0.42	0.50	0.54	0.67	0.20	0.37	0.52	0.66	0.25	0.32	0.42	0.60
Parent gearing (D/E)%	69	81	58	47	44	35	29	27	145	119	108	78
Parent gearing (D/D+E)%	41	45	37	32	31	26	22	21	59	54	52	44
Asset beta	0.25	0.28	0.34	0.46	0.14	0.28	0.40	0.52	0.10	0.15	0.20	0.34
Relevered at 60%	0.63	0.69	0.85	1.14	0.34	0.69	1.01	1.31	0.26	0.36	0.51	0.85

* Note: this is a monthly calculated figure for March of the respective year

6.52. As the above shows, obtaining a robust estimate for a DNO's equity beta is complex. Ofgem commissioned Stephen Wright and Smithers & Co to provide beta estimates for a range of companies[14]. London Business School data on betas indicates that since March 2004 betas have slightly increased but are still around the low end of this range. Based on the Wright and Smithers & Co report and recognising the uncertainty surrounding the forward looking equity beta, it is Ofgem's view that this range remains appropriate.

Gearing and tax

6.53. In the March document Ofgem presented a range for its gearing assumption of 50% to 60%. Ofgem also confirmed its intention to incorporate tax on a company by company basis directly into the financial model.

View of respondents

6.54. The majority of respondents supported the use of a common assumed gearing level for all DNOs for the cost of capital calculations. Several DNOs argued that the assumed gearing level should remain at 50%, given that an increase in the regulatory gearing level would be perceived as an expectation by the regulator that companies should increase their gearing.

6.55. It was also pointed out that a gearing assumption above 50% may lead to an inappropriately low overall WACC and that the CAA has acknowledged that there is no consistent academic evidence or normative model that predicts unequivocally the optimal capital structure. Given this and considering national and international evidence, it was argued that a gearing level of 50% may be close to the norm.

6.56. It was also argued that a higher gearing level would imply both a higher cost of equity and a higher cost of debt and that Ofgem should maintain an assumed gearing level of 50% despite evidence that investment grades can be maintained with higher gearing for the following reasons:

[14] Wright, S. and Smithers & Co (2004), Beta Estimates for: Scottish Power, Scottish & Southern Energy, Viridian Group, Centrica, International Power, National Grid Transco, United Utilities, Kelda Group, Severn Trent

- Higher assumed gearing level incentivises companies to push gearing levels even further;
- This will result in investment being financed through debt, pushing the industry average gearing even higher;
- This would result in less financial flexibility to respond to unforeseen circumstances and weaken incentives for innovation; and
- Care needs to be taken to avoid systemic failure within the sector.

6.57. In its response, energywatch stated that it does not support the post-tax approach to the cost of capital, as in its view:

- including specific estimates of tax costs will make the price control calculations more opaque and it would compound uncertainties in the price control outcome by adding taxation estimates to cost estimates; and
- it will incentivise companies to adopt a gearing level above the regulatory gearing assumption.

6.58. Several DNOs asked for clarification with respect to the treatment of tax. It was argued that the allowance of tax costs should be consistent with the level of gearing assumed in the balance sheet of the DNO as part of the financeability test used to ensure that the price control could be appropriately funded.

6.59. One DNO argued that the strongest incentive for tax efficiency and stability would be achieved through setting tax allowances based on the average industry position.

Ofgem's view

6.60. Ofgem will base the tax allowance on the company's actual gearing, or on the assumed gearing level for the cost of capital (e.g. 60%) if the latter is higher. Thus if a company has, say, 40% gearing (debt:RAV) its balance sheet will be adjusted to that of a company with 60% gearing and its tax allowance will be based on 60% gearing rather than its actual gearing level. However, if a company has, say, 70% gearing, its tax allowance will be based on its actual gearing level (70%).

6.61. As pointed out in the March Cost of Capital Appendix, one of the leading credit rating agencies considers that debt to RAV gearing in the range of 60% to 65% is consistent with target A3 (A-) ratings for comparable regulated network businesses.

6.62. In order to set an industry-wide cost of capital Ofgem has to make an assumption about gearing, given that gearing is a key input in the WACC. Ofgem's assumed range for gearing is 50% to 60% and Ofgem has adopted a 60% gearing assumption for its financial modelling. However, this does not imply that Ofgem is prescribing and/or endorsing any particular financial structure. In its view, and as set out in the December consultation document, these decisions are best left to the company and its financiers.

6.63. The rationale behind a post-tax rather than pre-tax approach to the cost of capital is to treat tax efficiencies like any other cost efficiencies. The post-tax approach enables the passing on to consumers of tax efficiency savings after a certain period of time.

6.64. Ofgem therefore considers that both its approach to tax and gearing as set out in the March Cost of Capital Appendix and the December document remains appropriate.

Expected cost of equity

6.65. In order to come to a view on the appropriate cost of equity Ofgem has adopted a return on equity approach alongside the traditional CAPM building block approach. Ofgem has applied DGM as a cross-check.

Alternative approaches to determining the expected cost of equity

6.66. One of the DNOs argued that the aggregate ROE approach is likely to understate the cost of equity because Smithers & Co use a forward looking estimate of the risk free rate and a historical ERP. It also argued that the alternative approach to combining the risk-free rate and ERP is achieved by assessing these two parameters as the average of a long-term historical time series and not by combining upper and lower bands.

6.67. Several companies argued that a CAPM approach might underestimate the cost of equity and that therefore more weight should be given to DGM.

6.68. One of the key inputs in DGM is the *expected* dividend growth rate. The NERA report for the ENA[15] adopts dividend growth rates in the range of 2% to 6% over the 1999-2003 period, based on IBES consensus analysts' forecasts. The report argues that analysts' forecasts of dividend growth provide the best proxy for short-term forecasts given that these forecasts:

- Provide a reasonable proxy for investors' expectations; and
- Reduce the degree of subjectivity in the choice of dividend growth rate.

6.69. For the second part of the DGM NERA adopts an annual dividend growth rate equal to the long-term forecast growth rate of GDP of 2.2%.

Ofgem's view

6.70. One of the main problems with using the DGM to estimate the cost of equity in a regulatory context is that the regulator also determines the maximum allowed revenue, with the cost of capital being a key input in this process. The potential dividend growth will therefore to some extent be determined by the total price control package. This gives rise to a degree of circularity. As pointed out by the Competition Commission[16]:

"A serious difficulty with the DGM is that expected future dividend growth rates depend on past and expected future regulatory decisions making it an unsuitable basis for estimating the regulatory cost of capital".

6.71. Several other UK regulators tend to use the DGM as a cross-check on the cost of equity obtained through CAPM and/or calculation of the ERP. This is also the approach adopted by Ofgem.

6.72. In calculating the initial range for the cost of capital, Ofgem applied the DGM as a cross-check for the cost of equity based on a CAPM approach and aggregate

[15] n/e/r/a (Hern, R. and Lowe, P.), Cost of equity estimates for electricity distribution network operators using a dividend growth model. A report for the Distribution Network Operators, 28 May 2004
[16] Competition Commission (August 2000), Sutton and East Surrey Water plc, A report on the references under sections 12 and 14 of the Water Industry Act 1991, London: The Stationary Office, paragraph 8.4, p.114

ROE approach. Ofgem's analysis was conducted on the basis of a one stage model which calculates the dividend yield based on ex dividend date prices and annualised dividends. In order to make the dividend yield *prospective* a growth component has been added to the base year dividend, this has then been divided by the ex dividend price.

6.73. Given the lack of 'pure play' companies, the analysis is based on data at corporate level of Scottish and Southern Energy, Scottish Power and United Utilities. The data therefore reflects a range of activities with different risk profiles and hence different reward expectations.

6.74. Ofgem has calculated the expected cost of equity using a one-stage model and dividend growth rate of 1% to 2% as well as a dividend growth rate in line with expected GDP growth (i.e. 2.25% to 2.5%).

6.75. The two stage approach adopted by NERA, relies on IBES consensus dividend forecasts for stage 1 and a dividend growth rate in line with the long-term forecast growth rate of GDP for stage 2. IBES consensus forecasts are based on the average forecast from a number of contributors. However, for the three listed groups which own distribution networks, the number of contributors for consensus estimates declines substantially for forecasts further into the future. For five years ahead, there is only one contributor for UU and SSE and only 2 for SP. This raises issues with respect to robustness of these forecasts especially when considering the wide variability of estimates in earlier forecast years.

6.76. NERA has used the forecast GDP growth rate for the second stage of DGM. However, no strong justification is given for using the long-term forecast GDP growth rate as a proxy for the long-run real dividend growth rate and it is worth noting that Dimson, Marsh and Staunton (2002) [17] find that GDP growth and real dividend growth do not appear to be positively correlated.

6.77. Ofgem is therefore of the view that although the DGM might provide a useful cross-check, no undue weight should be given to its outputs given the manifold problems with this approach and underlying assumptions which are further exacerbated due to the circularity problem in a regulatory context.

[17] Dimson, E., Marsh, P. and Staunton, M.(2002), Triumph of the Optimists, 101 years of global investment returns, UK: Princeton University Press

Range for the expected cost of equity

6.78. In the March document, Ofgem presented a range for the expected post-tax cost of equity of 3.75% to 7.50%. However, for consultation Ofgem excluded the bottom end of this range. The cost of equity (post-tax, real) used for financial modelling purposes is 7.25%.

Views of respondents

6.79. OXERA's range for the expected cost of equity is 5.25% to 7.5% based on a CAPM/ROE approach and 6.96% to 7.75% based on a DGM approach, based on 50% gearing. Based on a 50% gearing level, without issuance costs, NERA's calculation of the cost of equity using a DGM approach is 8.9%.

6.80. NERA's May 2004 report[18] presents the following figures for the real post-tax cost of equity using a 60% gearing level:

	DGM	**CAPM**
Real post-tax cost of equity (excluding issuance costs)	10.4%	9.3%
Issuance costs	0.3%	0.3%
Real post-tax cost of equity (including new issuance	10.7%	9.6%

6.81. Several respondents have argued that Ofgem should make an allowance for issuing new equity. It was pointed out that the Competition Commission allowed BAA a 0.75% premium on their cost of equity to enable a rights issue and that NERA includes a 0.3% premium to cover equity issuance costs.

Ofgem's view

6.82. Ofgem's range was arrived at through a combination of methods, i.e. CAPM and an aggregate ROE approach, with DGM as a cross-check. For financial modelling purposes Ofgem has adopted a post-tax cost of equity of 7.25%. This is towards the top-end of the proposed range and to a large extent based on an

[18] n/e/r/a (May 2004), Cost of equity estimates for Electricity Distribution Network Operators using a

aggregate ROE approach and also in line with Ofgem's DGM cross-check. The range put forward by OXERA (albeit assuming a 50% gearing level) is relatively close to the range on which Ofgem consulted in the March document, which discarded the lower end of its wider range.

6.83. Both in the case of a CAPM approach and a DGM approach, the available data reflects the risk profile of the parent company. It might be argued that a DNO is likely to face less rather than more risk compared with the activities of the parent company which might include generation, supply, etc. Hence, an adjustment for a higher gearing assumption at DNO level, without adjusting the risk profile for the other factors, is likely to overstate the cost of equity of DNOs.

6.84. As set out previously, the NERA range is based on questionable assumptions and might be expected to overstate the cost of equity of DNOs considerably.

6.85. Although the cost of issuing new equity in the long-term is likely to be very small, in the short-term it could be material. However, given that issuing new equity is a one-off cost, it does not seem appropriate to make an adjustment to the cost of equity for all five years. Instead, Ofgem will consider whether an allowance for issuing new equity should be included in the financial model when financial indicators suggest that this might be necessary. This would imply that such a potential adjustment could be made on a company by company basis.

The expected cost of debt

6.86. The expected cost of debt consists of the sum of the expected risk-free rate and the expected debt premium. The expected risk-free rate has been addressed in the expected cost of equity section.

Debt premium

6.87. In the March document Ofgem presented a range for the expected debt premium of 1.0% to 1.8%.

Views of respondents

6.88. The majority of DNOs supported Ofgem's proposed range for the debt premium, but several DNOs argued that the top-end of the range should be extended for embedded debt. Several DNOs also argued for an additional allowance for debt issuance costs.

Ofgem's view

6.89. The NERA report for EDF did not present an explicit debt premium. However, it assumed a real cost of debt of 3.75% and real risk-free rate of 2.9%. This would indicate an expected debt premium of 85 basis points. This might be appropriate for EDF, but given that Ofgem is adopting an industry wide cost of capital this is unlikely to be appropriate for all DNOs.

6.90. As set out in the March 2004 Cost of Capital Appendix, the current cost of debt is at historically low levels. The main issue is in how far the current data provides a robust estimate of the expected debt premium. As previously set out, considerable uncertainty surrounds the risk-free rate. Also, an increase in the risk-free rate could result either in an increase or a decrease in the yield on corporate bonds, depending on demand and supply conditions.

6.91. Given the planned investment and the scale of this investment, companies are likely to have to raise additional capital, which in part is likely to be through debt issuance. With this in mind, and given companies' concern with respect to efficiently incurred embedded debt, Ofgem has adopted an expected cost of debt close to the mid-point of the range for financial modelling purposes.

Cost of capital for initial proposals

6.92. As set out in the main document, the initial proposals are based on a pre-tax real cost of capital of 6.6%. However, this 'modelling assumption' for the initial proposals does not represent a decision on the appropriate cost of capital. Ofgem expects to make a decision on the cost of capital point estimate for final proposals.

Treatment of pension costs

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

6.93. In the March 2004 document Ofgem expressed the view that price controls should only provide for the recovery of pension costs relating to the business that will be subject to the price control. In practice this can be achieved by allocating active scheme members on the basis of current employment, scheme members that left employment since privatisation on the basis of last employment, and scheme members that left employment prior to privatisation either on the basis of last employment or, where records are no longer available, on the split of employment costs in the year of privatisation.

Views of respondents

6.94. Although the majority of DNOs were generally supportive of the principle that price controls should only provide for costs that relate to the business that will be subject to the price control, all had concerns about how this would work in practice with the majority expressing the view that they did not have sufficiently detailed records to allocate liabilities on the basis of last employment for post-privatisation leavers and calling for a more pragmatic approach. One of the DNOs said that they do not want DNOs with detailed records to be disadvantaged compared to other DNOs.

6.95. Two DNOs also argued that leavers from formerly bundled activities before legal separation should all be included in the price control allowance and a further DNO pointed to practical difficulties in allocating those employees between the current price-controlled and non-price-controlled activities.

6.96. One other respondent also expressed the view that it was not reasonable to split pensioners and deferred pensioners of demerged activities before that demerger had taken place.

6.97. On the allocation of pre-privatisation leavers, one DNO expressed a preference for allocating using employment costs in the year of privatisation. Another DNO expressed concern that alternative approaches were suggested for pre-privatisation leavers, which could lead a DNO to take advantage of the alternatives – they said that pre-privatisation liabilities should be allocated on a consistent basis across the industry.

6.98. One DNO stated that the use of current or last employment of individuals to allocate liabilities was biased against Distribution because since privatisation there had been a much greater movement of staff from Distribution to non-price-controlled activities than the other way round.

Allocation of scheme assets

6.99. In the March 2004 document Ofgem said that it was considering two options for the allocation of assets: in proportion to liabilities or matching as far as possible the type of assets held to the maturity profiles of the various categories of liability.

Views of respondents

6.100. One DNO favoured matching scheme assets according to maturity profiles of scheme membership categories. Three DNOs preferred to allocate in proportion to liabilities, citing the complexity of allocating by membership category and the view that it would not necessarily lead to any more accurate results.

Over or under provision

6.101. **In the March 2004 document Ofgem stated that it did not intend to make adjustments for past over/under funding (for DNOs this is the period to 31 March 2005 and for Transco the period to 31 march 2002) because of the lack of certainty about the amounts that may have been allowed in past price controls. However the principle remains and at future price controls Ofgem**

will review whether pension cost allowances have been too high or low and adjust the future price controls accordingly.

6.102. All DNOs favoured the proposal not to adjust for past over/under funding as did two other respondents. There was widespread agreement that the lack of an explicit allowance in previous price controls meant that it would not be possible to do this exercise and also some disagreement with the idea in principle saying that to do so would be retrospective regulation.

6.103. Three of the DNOs disagreed with Ofgem's comment that DNOs have probably contributed less than they were allowed in previous reviews as there was no explicit allowance for pension costs in previous price controls.

6.104. One DNO said that the decision not to adjust for past over/under funding should not be dependent on the acceptance of Ofgem's position on Early Retirement Deficiency Costs.

6.105. One DNO stated that future adjustments should be based on a cost pass through mechanism because waiting until a subsequent price review for any adjustments could create significant cash flow issues and there was also some doubt about the transparency of those adjustments at subsequent reviews. One other respondent also expressed concern about the clarity with which any adjustment was subsequently made, stating that any lack of clarity would increase regulatory uncertainty and thus the cost of capital.

Early Retirement Deficiency Costs (ERDCs)

6.106. **In the March 2004 document Ofgem remained minded not to allow any ex post pass through of costs relating to the funding of Early Retirement Deficiency Costs from pension scheme surpluses at the time.**

6.107. All DNOs argued against deducting ERDCs from the allowed deficit. They argued that it was a legitimate use of surpluses which provided efficiency savings for customers and that those past efficiency gains are already included in the benchmarking of future costs. They argue that since little or no allowance for severance costs was provided in DPCR3, use of pension scheme surpluses in this manner to fund the efficiencies in that review was appropriate and legitimate.

Also one DNO said that in a previous response they had not said that there was an agreement over ERDCs at DPCR3.

6.108. The DNOs also argued that since at previous price control reviews Ofgem must have been aware that surpluses were being used in this manner and gave no indication that those costs would subsequently be disallowed, to do so now would be retrospective regulation. It was unreasonable to now put the burden of proof on DNOs to demonstrate that there was agreement at the time to allow the recovery of these costs.

6.109. While many DNOs argued that there should be no adjustment to deficits for the extent to which ERDCs were funded out of surpluses (i.e. all the cost of ERDCs should be funded through the price control), a few argued that 70% of the cost of those ERDCs should be passed on to customers through the price control reflecting the 70:30 share of benefits from efficiency gains.

6.110. Three other respondents also argued against deducting ERDCs from the allowed deficit for similar reasons to the DNOs. One of them stated that 70% of benefits of efficiency gains went to customers, implying that the costs should be shared in the same manner.

6.111. One respondent said that Ofgem seemed to indicate in the document that it had taken a proportionate approach by not taking account of under payments against price control assumptions but taking full account of ERDCs. If there had been an overpayment against price control assumptions they would therefore expect ERDCs not to be clawed back.

Other pensions comments

6.112. One DNO argued that legitimate costs that are stranded as a result of the removal of metering (such as pension costs) should not be removed to the separate metering business control but should remain as part of the main price control.

Ofgem's view

6.113. Ofgem will be considering further the detailed issues including the allocation of assets in the summer and will report back in the September document. It notes the comments of the respondents to the March document.

6.114. The ERDC issue is discussed further in chapter 7 of the main document. The issue of pension costs and the metering price control will be discussed in the September document.