EDF Energy's response to Ofgem's second DPCR4 consultation: summary of our key points

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Dear Nienke

<u>OFGEM'S SECOND CONSULTATION PAPER ON THE ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW</u>

We are pleased to be able to comment on the above document.

The overall picture painted by the consultation is that much work is required by both Ofgem and the distributors if the high level proposals contained in the paper are to be translated into practicable new price control and incentive mechanisms. We therefore recommend that Ofgem should prioritise its work and defer consideration of matters which are not central to the review.

Our key points are these**:**

<u>Form, structure, and scope of the price controls</u>

- The current balance between customer and volume revenue drivers in the main price control should be retained for the duration of the next price control period. Demand displacement by on-site generation may make it necessary to modify the drivers at the next (i.e. fifth) review.

- The introduction of NGC's "plugs" charging methodology will reduce exit charges paid by EDF Energy to a level that does not warrant a bespoke incentive. Existing exit charges are not under a distributor's control and material new charges occur infrequently. Concerns about a distributors's appetite for investing in its network should be addressed by raising the cost of capital.

- We are not aware of dissatisfaction among our EHV connected users and would like to hear any as yet unarticulated concerns. A price cap (based on units or capacity, or on some mix of both) is unlikely to provide additional revenue to match the additional costs of a new EHV connection, and would discourage distributors from accepting expensive connections – which is why they were classed as an excluded service in the first place.

- We do not support the introduction of live jointing on our networks by third parties as it is clear that, while we would have a health and safety liability in respect of the persons concerned, we would not have the appropriate degree of management control over them.

- We do not accept that any differences in the statutory regimes applicable to water and electricity are relevant to the inclusion of re-opener mechanisms in the price control. There must be a robust and enforceable mechanism to enable unforeseen cost shocks to be appropriately incorporated within a modified price control. We propose a specific mechanism for achieving this that should meet both distributor and Ofgem requirements.

- The very significant costs (potentially up to £30m a year for each distributor, mainly from lane rental and additional reinstatement costs) that will arise from the government's traffic management legislation must be addressed within this price control review.

- We oppose the "general" nature of the intended eligibility tests for efficiency rewards, as they will inevitably lead to a subjective and unpredictable application that will weaken incentives. By their nature, such tests will be based on a lower standard of evidence than is required for the use of Ofgem's formal powers. There are no associated appeals mechanisms open to distributors, apart from judicial review.

- We support and promote the use of long-term quality of supply incentives to ensure that distributors do not take short-term investment decisions that could compromise the long-term integrity of their distribution networks. However, such incentives should be specific, rather than general, and the parameters must be fully defined in advance. We set out the desirable features of such a scheme.

- We agree that best-performing companies should be able to earn a higher than average rate of return. However, we believe that the proper way to achieve this is by setting revenue in relation to average costs. We do not believe that Ofgem's cost-normalisation will be robust enough to support the use of frontier cost levels. Moreover, the use of frontier costs is not consistent with average rates of return for all companies.

- Ofgem has, through its disaggregation of quality of supply data, proposed some initial benchmarks for quality of supply out to the year 2020. But the results of this work are deeply flawed, with the effect that the suggested 2020 performance levels for EPN and SPN could be achieved only through a radical reconfiguration and strengthening of their networks, combined with technological advancement in real-time condition monitoring.

- Ofgem is unable directly to regulate new meter owners/operators (whose activities do not require to be licensed). In these conditions, proposals to impose specific obligations on distributors, while not imposing equivalent obligations on alternative potential new entrants, will distort competition, not promote it. Any metering price control must allow the distributors to recover all sunk costs, including those that may be expected to arise through suppliers' accelerated replacement programmes.

Quality of service and other outputs

- Ofgem's focus on driving up both the service thresholds and associated penalty payments under the guaranteed standards effectively exposes companies to rising levels of financial risk which they cannot practicably or cost-effectively mitigate through increased investment.

- The interim scheme for guaranteed service standard payments following a severe storm should form the basis of a more enduring scheme. But refinement is needed regarding the time from which the compensation applies, since the current 48-hour threshold would not be appropriate in respect of a storm causing widespread damage.

- We believe that it is inappropriate to link penalty payments for business users to their daily transportation charge. If such an approach were to be taken, then it would be consistent to also link penalty payment for domestic customers to their daily transportation charge. For our three licensees this would equate to approximately 13 pence per day.

- The making of accurate automatic penalty payments for failures at any voltage level is currently impracticable. The models developed for the IIP scheme are not 100% accurate at any voltage level. They were designed to report performance to specified accuracy levels for total measures, and not in relation to individual events.

- The purpose of the exemptions from the guaranteed service standards was to provide all distribution companies with protection against events which were outside their control. Any reduction or removal of these exemptions would increase both the actual and perceived risk faced by distributors, and hence have an impact on the cost of capital.

- We support the removal, where appropriate, of specific overall standards. of performance. For example, the existing OS1b standard is effectively duplicated by the IIP scheme and could be removed. The general test is that if any overall standard is duplicated in another incentive scheme, it should be removed

- We do not believe that it is relevant to disaggregate the quality of supply reporting on a customer-type basis. Most customers are connected to the low voltage network, the design of which means that the delivered quality of supply will be the same, regardless of customer-type.

- We agree that the appropriate form of a worst-served customer standard needs further debate. We have consistently argued that a single-year, multiple-interruption target is inappropriate. This is because, in any year, a proportion of customers will experience a high number of faults through the combination of unrelated, sporadic events. We cannot invest sensibly to insulate our networks from such events.

- We believe that marginal IIP rewards must be higher than the marginal penalties. This is because the balance of risk is becoming increasingly asymmetrical. Moreover, both dead-bands and rolling averages, as mechanisms for dealing with annual variability, would have a number of negative incentive effects regarding the enduring impact of single events/years.

- We are pleased that Ofgem intends to examine regional bias in its own customer satisfaction survey. We have consistently stated that regional bias exists and must be taken into account in assessing the survey results.

Investment in distributed generation

- We have consistently supported the need for an appropriate mechanism to incentivise distributors in relation to the connection and operation of distributed generation (DG). We are therefore pleased to see Ofgem's continuing development of such an approach. However, we consider that the scheme, overall, lacks ambition, given the profound impact that climate change is expected to have.

- There are still some significant issues that need to be resolved before it can be agreed that a wholly workable and acceptable incentive regime has been derived. These issues include**:**

  - overall rates of return, especially since these are dependent on the cost of connection and the proportion of expected generation that actually connects

  - the risks surrounding the emergence of unexpected schemes with very high connection costs

  - the treatment of future non-project-specific strategic and overall DG related costs

  - the level of return necessary to incentivise distributors to invest in preparing networks for DG ahead of the emergence of specific connection requests while avoiding stranded costs

  - the level of the O&M supplement to the incentive rate, and which costs are intended to be covered by this

  - the linkage between the scheme and the current statutory framework for connections

  - which customer groups are to meet these costs, and the linkages with the structure of charges project, and

  - the suitability and practicality of the availability incentive.

Ofgem's assessment of costs

- We agree with the three principles which Ofgem says should be applied to cost bench-marking analysis. We trust that Ofgem will abandon this approach if any of these principles cannot satisfactorily be met.

- We asked NERA (National Economic Research Associates) to examine CEPA's total factor productivity (TFP) study, and its comments are set out in the attached report. EDF Energy fully endorses NERA's views. The use of TFP analysis is a step forward in calculating X factors, as it provides an objective basis for setting the future cost reduction targets. However, NERA's critique of CEPA's TFP work highlights a number of fundamental problems with this work.

- It is wholly unclear how Ofgem's current merger policy will be applied retrospectively and therefore we require further detail on its practical application before we can suitably comment.

- Our primary concern with regard to the roll-forward of the RAV is that the methodology applied should result in the full allowance of expenditure incurred efficiently in the current control period. We believe that the only acceptable outcome in this area is for Ofgem's approach to ensure that all legitimate costs relating to the activities undertaken by distributors during this period are funded and that customers pay once, and once only, for the efficient services they have received.

- We have provided Ofgem with evidence that the accounting policies followed by our three distributors left network fault replacement-related expenditure in capex in 1997/8. Our proposed solution is therefore that for the whole of the current control period we should continue to include in the capex that is being added to the RAV the same proportion of overall fault costs as applied at that earlier time.

Financial issues

- A cash lock-up is a heavy-handed device which should only be invoked in the most extreme circumstances. There are market mechanisms already in place for restricting cash distributions, for example via debt covenants. (There is an increasing trend for use of debt covenants for debt:RAV gearings above 60–65%.)

- To avoid unnecessary rigidities in financing arrangements, a cash lock-up mechanism should only be invoked when insolvency is imminent (as evidenced, for example, by an actual downgrade below B– into any C grade rating).

- Ofgem has set out a number of proposals for changing the method of calculating WACC. As currently drafted, the proposals contain errors and substantial room for inconsistent use of discretion.

- Ofgem should calculate the cost of capital in terms of at least one standard method (for example, CAPM) and should use other methods as a cross-check on the answer. Using only one method for calculation imposes a necessary degree of consistency**:** the cross-checks can then be used for calibrating the parameters within the method.

- Ofgem has also used, and now proposes to continue using, survey data for estimating equity risk premium (ERP). NERA commented in its earlier submission for EDF Energy that the survey data that Ofgem has used in the past have been unreliable and dated. We are concerned that the use of ad hoc survey data reduces the objectivity of the process.

- We/NERA also consider that mixing historical data and spot-price data is internally inconsistent and can cause biases because of the inverse relationship between ERP and the cost of debt. In times of high market volatility, ERP rises to reflect higher required equity returns, but yields on risk-free assets and the cost of strong corporate debt fall as investors reallocate portfolios towards less risky government and corporate bonds.

- If Ofgem does decide to proceed with central case projections as the basis for setting prices, rather than a wide range of scenarios, the thresholds should not be those applying in a situation of relative certainty. Ofgem should adopt threshold levels for financial ratios that are some way above the minimum levels needed for the chosen credit rating, to allow both for the likelihood that the outturn will be worse than the central case, and also for the consequences (such as default or bankruptcy) in such an eventuality.

- As regards the treatment of pension costs, Ofgem should not introduce a further test (of stewardship) that it cannot hope to measure objectively. At the least, Ofgem should set out a detailed interpretation of what, in its view, constitutes acceptable stewardship practice.

- Our views on Ofgem's other pension cost guidelines remain unchanged. We particularly disagree with the proposal to make allowance for only the network monopoly part of the overall business, the construction of ex-post assumptions about the level of employer contributions allowed for in previous reviews, and the treatment of early retirement deficiency costs.

We hope that this response is helpful. Please do not hesitate to call me if you have any concerns or queries.

Yours sincerely

Paul Delamare

Head of Price Control Review

EDF Energy plc

EDF Energy's response to Ofgem's second DPCR4 consultation: the form, structure, and scope of the price controls

Revenue drivers

We support the continued use of the current revenue drivers and weightings for the next price control period. In the longer term, however, the price control will need to be amended to take account of the cost of providing network support to distributed generators.

We agree with Ofgem that there is little risk of the distributors increasing units distributed by promoting the inefficient use of electricity. By implication, therefore, such considerations should no longer interfere with the recovery of the marginal costs imposed by load growth.

Ofgem is contemplating separate arrangements for driving allowed distributed generation revenue, the details of which are currently unclear. We understand that Ofgem's current thinking is that (for an initial period at least) the scope of such mechanisms would recover only the cost (net of any connection charges) of new assets provided to connect the generator (including any relevant share of upstream reinforcement), and not the use of existing assets. This approach would mean that the costs associated with the generator's use of existing assets would remain with demand customers.

Should consumption be materially displaced by on-site generation (for example, through the widespread adoption of domestic CHP), it may be necessary to modify the balance between customer and unit drivers, or to add an additional driver. However, we do not currently anticipate that such changes will prove necessary in the next price control period.

EHV connections

We presume that Ofgem is contemplating introducing a capacity driver so that it is possible to include EHV connections within the price control. However, we oppose such a development because the costs of EHV connections are highly variable, so a price cap (based on units or capacity – or some mix of both) is unlikely to provide additional revenue to match the additional costs of a new EHV connection, and would discourage distributors from accepting expensive connections – which is why EHV connections were classed as an excluded service in the first place.

NGC exit charges

We strongly support the retention of the existing 100% pass-through of NGC exit charges.

The materiality of these charges will be much reduced from 1 April 2004 as NGC's new "plugs" charging methodology comes into effect (exit charges paid by EDF Energy are expected to halve from around £54m a year to £26m across its three licensees**:** around only £9m each). In our view, the case for bespoke incentives on such relatively small sums is weak.

More importantly, "our" grid supply points comprise assets for which the costs are sunk. Indeed, should such assets become redundant, the sunk costs are not avoided, as NGC levies a termination charge to recover all outstanding investment costs. EDF Energy therefore has no control over these costs and any controls to restrict pass-through applied to them would have no useful incentive effect but would merely put cost recovery at risk.

Ofgem appears to be considering a partial pass-through regime for NGC exit charges (paragraph 3.53 refers). Currently, both distributor capex and NGC exit-related capex are subject to a 100% pass-through to customers over time. Distributor capex (within spending targets) is fully passed through to customers over time through the RAV mechanism – including the associated funding costs (provided that an appropriate cost of capital is used). NGC exit charges likewise represent a recovery of cost over time and associated funding costs. However, distortion of incentives could occur because:

- Distributor capex is subject to strong incentives for cost-efficient deferment, and
- The distributor's regulatory cost of capital is insufficient to attract discretionary investment.

However, only new spending decisions are affected by these incentives and, because GSP investments are infrequent and varied, it would seem to be impractical to design a bespoke incentive. The key to balancing incentives would seem straightforward – Ofgem should make the cost of capital for distributors more attractive to new investment.

Ofgem also notes that the take-up of distributed generation could reduce the level of expenditure on transmission/distribution interfaces. In the long run, this may be the case as networks are gradually reconfigured in response to changing patterns of demand and generation. However, as noted above, it could not impact on the level of sunk costs that need to be recovered. We are confident that distributed generation is unlikely to materially impact exit charges in the next price control period for EDF Energy GSPs.

Wheeled units

Charges for wheeling units between distributors comprise a use of system component and a share of NGC exit charges. Typically, the use of system element will be more significant than the exit charges. Therefore, in order to balance incentives between wheeling and use of the transmission network, Ofgem should focus, not just on the relatively minor exit component, but on mechanisms to enable the recipient to recover all elements of wheeling charges.

Whether the "source" distributor is subject to incentives on the level of NGC exit charges would seem to be irrelevant with regard to the construction of the price control applicable to the recipient distributor.

Extra high voltage (EHV) charges

We do not believe that Ofgem has justified any future inclusion of EHV charges within the price control.

Ofgem records the view of one EHV customer that these charges have not fallen as fast as other distribution charges. However, this is hardly surprising because the fall in regulated charges is largely explained by:

- The changes in the accounting rules that Ofgem imposed on the RAV (1995/96),
- The allocation of operating costs (1999) for costs covered by the price control, and
- Genuine falls in operating expenditure.

Conversely, EHV costs have not fallen to the same extent because:

- EHV asset values were more clearly defined,
- The re-allocation of operating costs affected regulated services, not EHV connections, and
- EHV connected users pay relatively low operating costs anyway.

Thus, as charges reflect costs, there is no scope for lowering them other than by allocating the costs of these dedicated facilities to other customers.

On the question of the variability of and risk associated with these charges, Ofgem says that "on average they have fallen broadly in line with the assumptions underlying the price control". Presumably this seeks to imply that the variability in such costs does not merit their exclusion from the price cap. But in practice, it is impossible to assess risks by looking at averages.

Ofgem's approach rejects arguments in favour of the current system, but offers no strong arguments in favour of these three alternatives except for the observation in paragraph 3.31 that EHV charges have shown a wide range of movements (relative to each other). At no point does Ofgem discuss whether EHV charges have fallen in line with costs.

We are not aware of dissatisfaction among our EHV connected users, and would welcome hearing any as yet unarticulated concerns.

Non-contestable connection charges

Cross-subsidy: Ofgem says that distributors may be "cross-subsidising" their competitive activities from charges recovered from non-contestable connections. Ofgem's allegations are not supported by evidence. If distributors wanted to cross-subsidise an activity, they could use funds from any source and would not need funds from connections. In any case, distributors have no incentive to give away funds by cross-subsidising competitive activities.

Price control treatment: Connection charges comprise**:**

- Contestable work – which should be removed from the scope of regulation in line with development of competition,

- Non-contestable reinforcement and diversion work – which is too variable to be included in the main price control (particularly at the moment, as revised connection charge principles have not been decided), and

- Administrative work (including charges for point of connection assessment, updating asset records, site liaison, and asset adoption) – the costs of which could be treated by distributors as opex and included within the price control once more experience is gained of volume and variability over time.

<u>Increasing the scope of contestable work</u>

Currently, the volume of connections provided by independent connection providers (ICPs) in the EDF Energy area is small. This is consistent with the statistics published by Ofgem, which suggest that ICPs account for only 4% of the contestable connections market by volume. However, our experience has been that ICPs are primarily interested in high profile, high cost, major connection projects. As a result, the share of the contestable connections market undertaken by ICPs in terms of financial value is much higher and in the region of 10–15%.

This situation is further complicated by the advent of embedded networks (see also our comments about gas regulation above). The distributor may provide a single point of connection to an embedded network operator who could be providing connections to thousands of consumers on the embedded network.

The effect of this for the distributor would be**:**

- The loss of many new connections, which will not appear in Ofgem's statistics, and

- The loss of a substantial part of the connections market in terms of financial value.

For the above reasons, we believe that Ofgem should assess the competitive market by reference to the financial value of work undertaken by the ICPs (information which it will need to get from them) as well as to the volume of connections.

Live jointing

We believe that adoption of new connection assets by us (and the associated transfer of responsibility) must occur at the time that those assets are first connected to our networks. This approach brings clarity and certainty to the operational interface and is clearly in the interests of connected customers.

This means that all live connections, even those to new networks within the confines of a development site, involve working on live assets within the control and ownership of EDF Energy. We have a responsibility for the safety of any ICP staff undertaking live jointing and also a liability for the safety of the general public, who may be the users of, or come into contact with, any new network connected. This is a view supported by the Health and Safety Executive, which has confirmed in writing that distributors will have responsibilities for heath and safety in all the various scenarios that arise in the course of making live connections to distributor networks.

It is for the above reasons that we are strongly opposed to the introduction of live jointing by ICPs. It follows that the live jointing trials currently in progress for “greenfield” sites will not lead to live jointing becoming contestable during 2004 as Ofgem suggests.

It is also worth pointing out that, for many new connections, restrictions on live jointing are not a significant issue. For projects involving a single connection, the ICP can complete all the contestable work (dead working) and then arrange a date for EDF Energy to make the final live connection. The more difficult projects are the medium size and larger housing developments, where construction will be progressed in many small phases and where the overall design may change during the course of the construction work. Uncertainties around the build programme rate (possibly dependent on sales success) mean that it is difficult to establish the number of live connections and their timing at the planning stage.

However, it should be possible to overcome these difficulties through better coordination between ICPs and distributors with respect to planning inspections and programming live jointing. Clearly we would wish to avoid a situation where the ICP installs the low voltage network and EDF Energy undertakes virtually all the live service connections.

Standards of service

A simple set of standards of service has been applied to new connections work for many years. The small number of complaints and referrals to energywatch and Ofgem suggest that these standards are working effectively and that EDF Energy is providing a service that is generally in line with customer expectations. It would be undesirable to replace a system that is simple and effective in its application with an onerous set of standards that are difficult and expensive to apply and monitor. We believe that any new standards should be proportionate to the service being provided.

Business rates

We agree that it would be sensible to wait for proposals from the Valuation Office before considering how best to incorporate the cost of business rates into any revised price control arrangements.

Hydro-benefit

The Secretary of State has proposed legislative measures which would result in distribution costs in the North of Scotland being subsidised at the same level as under the hydro-benefit subsidy scheme but with the subsidy being recovered from all suppliers in Great Britain.

We assume from the DTI's recent announcement that, whereas the current subsidy enforced by licence conditions may be contrary to EU law, the proposed subsidy supported by statutory order is considered not to be. We have previously requested that legal advice received by Ofgem and by the DTI relevant to this issue be published without delay.

While we accept the principle that customers in the North of Scotland, as a genuinely peripheral area, should continue not to be fully exposed to the impact of exceptionally high distribution costs, we would like to see new justification, within the context of EU legislation, for the continued extent of the necessary subsidy. For example, will it be designed to bring charges down to and then maintain them at a certain level relative to average distribution charges or to charges in the next most expensive area?

Duration of the main price control

We agree that a five year price control is appropriate. However, there is a clear need to increase the power of efficiency incentives through the rolling mechanisms – which can themselves be independent of the length of the main price control.

Dealing with uncertainty and new obligations

We consider that a formal re-opener mechanism should be built into the price control to protect distributors from material cost shocks of a scale that could otherwise jeopardise their ability to fund their activities. A licence-based mechanism would be more certain, for this purpose, than the use of regulatory comfort letters, which can only deal with a limited scope of known issues.

The potentially very significant costs (of up to £30m a year for each distributor, mainly in the form of lane rental and additional reinstatement costs) which could arise from the government's proposed traffic management legislation are a prime example of the need for distributor protection. A sudden and unexpected requirement to accelerate the replacement of fluid-filled cables would be another example.

Comparison with Ofwat approach

Ofgem rejects the more formalised approach adopted by Ofwat by arguing that the two industries differ. However, the alleged differences do not survive scrutiny in this context**:**

- **Ofgem and Ofwat have different statutory duties.** This is incorrect. Under the Water Act 2003, Ofwat's principal objective is formulated in exactly the same terms as Ofgem's**:** it is to protect consumer interests, wherever appropriate by promoting competition. Even if that were not the case, we would argue that the legal requirement on the regulator to ensure that regulated companies can finance continuing investment, by earning a rate of return sufficient to attract capital from investors, is, for all practical purposes, identical in both industries. In principle, therefore, there seems no good reason why a formalised aproach to uncertainty should be deemed to be appropriate for water, but not for electricity.

- **The magnitude of cost uncertainties differs.** This is an empirical question. However, it is unclear why Ofgem believes that lane rental charges should affect the water industry more than the electricity distribution industry.

- **It is preferable to address uncertainty ex ante rather than assessing after the event whether adjustments should be made.** The whole purpose of a well-defined re-opener mechanism is to remove uncertainty over how Ofgem will react to future variation in costs, by setting out <u>in advance</u> a procedure for reacting to new information. The formulation at paragraph 3.60 of Ofgem's paper does not set out a procedure for "addressing uncertainty ex ante", but only for "assessing after the event whether adjustment should be made". Ofgem's proposal is therefore inconsistent with the observation in the text.

- **It introduces a significant burden on both the regulator and the company as the process for an interim determination in water typically involves a significant amount of work.** Ofgem overlooks the possibility that some "work" is desirable to avoid other problems during a regulatory period, and that it is certainly possible to minimise its extent.

  It should not be necessary to conduct a full interim price determination (essentially, a new review) if only one specific cost item has changed (for example, business rates). A well-drafted re-opener mechanism would limit the scope of any work to examining whether a particular cost had changed, with a view to authorising an adjustment to the specific allowance for that line item. The obvious corollary of this is that Ofgem must have specified the basis on which it set the original allowance.

- **Ofgem does recognise that there are some categories of cost which are currently very uncertain and dependent on decisions by third parties. One example would be lane rentals.** We take this to mean that Ofgem does accept the need for some limited revenue adjustment formula that is different from simple cost pass-through. In fact, the example cited by Ofgem lends itself readily to just the kind of automatic approach that we advocate. In setting a revenue allowance for lane rentals, Ofgem needs to specify only a volume and a price. It would then be simple to update this allowance for changes in the price, which are outside the control of the distributors, without changing the volume and without affecting distributor incentives to minimise costs. Indeed, if a cost item is (a) highly uncertain and (b) exclusively controlled by third parties (because there is no possibility of substitution by distributors), then 100% cost pass-through cannot affect distributor incentives. In other words, replacing cost pass-through with some other allowance would merely impose unnecessary risk on disributors.

Our proposal

In the light of the above analysis, we recommend that the price control special conditions should include supplementary price caps dealing with the remuneration of uncertain cost categories. These caps would embody Ofgem's best estimate (at the time the price control is set) of the efficient level of costs in each of the uncertain categories. (The amount could be set initially at zero if Ofgem doubted whether the cost would arise at all.) However, these price caps would have embedded within each of them a right for the licensee to notify Ofgem that the amount built into that particular cap at the outset should be replaced by another amount that corresponds to the material costs that the licensee believes is more likely to be an accurate level of the costs that are likely to be efficiently incurred.

Each supplementary price cap would provide that, on receipt of such a notice, Ofgem could**:**

- Do nothing, in which case the revised amount notified by the licensee would become effective in the supplementary price cap, or

- Give the licensee a counter-notice stating either that Ofgem considered that the original value should be maintained, or that Ofgem proposed an alternative value.

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

If Ofgem's original cost estimate appeared likely to be too generous to the licensee, a similar mechanism would be needed to bring about a reduction in income compared to the initial view taken in the setting of the supplementary price cap. In these circumstances, the mechanism would work as follows. Ofgem would propose a new value (perhaps after seeking information from licensees or other bodies). The licensee would accept Ofgem's proposal or reject it. If it rejected Ofgem's proposal the licensee could propose its own alternative. Ofgem could then accept that alternative, leave the amount as it stands, or refer the matter to the Competition Commission.

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

Incentive framework

(a) Eligibility tests: Ofgem has indicated that it will take a general view of compliance with quality and security of supply obligations when assessing whether a distributor is "eligible" for rewards under the capex efficiency incentive. Ofgem also considers that such eligibility tests should be extended to cover the opex efficiency incentive for the next price control period.

We consider that such general tests are not a good development in regulatory practice. In particular**:**

- Ofgem already has adequate enforcement powers, including the power to impose substantial fines for non-compliance. If non-compliance has occurred, it should use these powers. There is no justification for the creation of another layer of de facto fining powers.

- More specifically, the "general" nature of the intended eligibility tests can only mean that the manner of their application will be so subjective and unpredictable that incentives are bound to be weakened. Such tests will inevitably be based on a lower standard of evidence than is required for the use of Ofgem's formal powers. There are no associated appeals mechanisms open to distributors, apart from judicial review in certain narrow circumstances.

We support and promote the use of long term quality of supply incentives to ensure that distributors do not take short term investment decisions that could compromise the long term health of their networks. However, such incentives must be specific (not general) and the parameters must be fully defined and specified in advance.

(b) Exceptional costs: Ofgem is proposing not to exclude exceptional costs from the rolling opex incentive.

We agree that it would be difficult for Ofgem to define in advance what would constitute an exceptional cost. However, Ofgem cannot avoid ex-post consideration of such costs during price control reviews if it wishes to rely on cost benchmarking (particularly if panel data is to be used) and to monitor (and report on) performance against the price controls. So the work involved would appear to be required anyway**:** it is just a question of timing.

We think that it would be inappropriate to create a regime in which distributors had an incentive to submit numerous and burdensome exceptional cost claims. However, incentives would be undermined if**:**

- Costs increase because of new and externally driven exceptional costs (the link here with Ofgem's desire, at paragraph 3.59, to only recognise such matters ex-post is particularly obvious, as it would mean that the relevant cost allowances do not change within the price control period),or

- Exceptional costs of change (i.e. investment in future efficiency savings, such as restructuring and severance costs) are not excluded.

Retaining the interim commitment not to allow incentive rewards to fall below zero would be one way of softening the impact of a "no exceptional costs" rule. However, in addition, and particularly if uncertainty is to be addressed only ex-post, it should be possible to exclude exceptional costs (categorised as such in accordance with regulatory accounting guidelines) above an objective materiality threshold – say £1m annually per licensee per cause.

(c) Use of frontier multipliers: Elsewhere in this response, we explain why we do not support the use of a "frontier" approach to setting price controls. Instead, we prefer the use of an average cost approach, because this does not transfer risk to non-frontier companies. An average cost approach would also enable distributors with better than average cost efficiency to achieve a rate of return higher than the regulatory cost of capital (an outcome which would appropriately mimic the behaviour of competitive markets). Should Ofgem persist with a frontier approach, multipliers can be used to achieve the same effect.

(d) Treatment of overspends: We would support mechanisms that enable the full recovery of costs associated with any efficient capex overspends, including back-dated returns on the investment as well as back-dated recovery of regulatory depreciation.

(e) Rising capex allowances: Where companies are proposing large increases in capex, Ofgem is rightly concerned that expenditure is not inappropriately deferred in order to "game" the efficiency incentive mechanism. Ofgem is proposing a number of options for addressing this concern**:**

- Use of “outputs” that customers value
- Use of ”intermediate outputs”
- A smaller (per £) reward for distributors with large programmes
- Rewards for companies with smaller total cost spends

With regard to the last two options, we have great difficulty with the notion of “smallness”. After all, a low spend may merely reflect an historic portfolio of asset ages – or it could equally indicate that a company may wish to take greater risks (against consumers’ interests). It is too simplistic to suggest (at paragraph 3.80) that a low spend may “reflect total cost efficiency”.

<u>Our preference is for an output regime based on incentives for achieving long-term quality of supply outputs</u>. The current IIP scheme has been an important first step in this direction. However, both the scope and level of performance targets have no continuing life beyond the current price control period. Yet, the significant replacement issues described in our forecast business planning submissions address long-term needs (over 20+ years in some cases).

<u>Ofgem should address this significant gap in the incentive regime in this price control review.</u>

A long-term quality of supply scheme can be envisaged, and might have the following features:

- Incentive rewards and penalties would be available in respect of short term quality of supply performance as with the current IIP scheme.
- Incentives for the efficient deferment of capital expenditure would be available along the lines of the current rolling capex incentive.
- The marginal incentive rate could be subject to a sliding scale so that it falls where underspends exceed a suitable dead-band threshold.
- Long-term incentives could be provided by introducing a claw-back mechanism covering, say, five-year rolling blocks of capex incentive rewards.
- Appropriate levels of capex, as proposed by the companies, would be “allowed” by Ofgem.
- The path of the quality of supply targets would be long-term (over at least 15+ years), based on rolling average past performance.
- The scheme would give rise to a contingent liability, which could appear in distributor regulatory accounts.

- Clear and specific claw-back rules would be in place, in particular to protect distributors from uncontrollable externalities (such as major storms, war, or terrorist attack).

Ofgem has, through its dissagregation of quality of supply data, proposed some initial benchmarks for quality of supply out to 2020. However, the results of this work are deeply flawed, and have the effect (for example) that the suggested ultimate performance levels for our EPN and SPN companies could only be achieved through a radical reconfiguration and strengthening of their networks, combined with technological advancement in real-time condition monitoring.

There is no evidence that customers are willing to pay for the restructuring of networks on this scale, which implies that the benchmarks are too low. (We have separately given Ofgem our investment analysis that lies behind this conclusion.) It is for this reason that we have proposed that a long-term quality of supply scheme must be based, not on Ofgem's benchmarking work, but on a different set of standards more reflective of customer expectations.

Price controls for metering services

Ofgem has proposed that there will be a separate price control for metering services commencing on 1 April 2005. Ofgem plans to proceed on the basis that a price control will cover both meter asset provision (MAP) and meter operations (MOP) for all non-half-hourly meters. This control would take the form of a price cap for MAP and an average revenue cap for MOP.

Ofgem believes that the distributors' ownership and operation of meters are an obstacle to the development of supply competition. However, Ofgem has not shown that this obstacle (if it exists) is unique to the distributors, since it stems from the transaction costs of switching, not from the distributors' dominant position in any particular supply market. This problem applies to any incumbent meter owner/operator, not just the local distributor. The introduction of alternative meter providers/operators does not eliminate this barrier to competition, but merely transfers its ownership to someone else.

Ofgem is unable to directly regulate new meter owners/operators (whose activities do not require to be licensed). In these conditions, proposals to impose specific obligations on distributors, while not imposing equivalent obligations on alternative potential new entrants, will distort competition, not promote it. Any metering price control must allow distributors to recover all sunk costs, including those that may be expected to arise through suppliers' accelerated replacement programmes.

To the extent that Ofgem thinks that meter asset ownership is the cause of competition problems, it might be better to overcome the obstacles through standardised access rules. After all, Ofgem was only able to achieve a full separation of distribution and supply when the Utilities Act required the separate licensing of each activity.

Ofgem may want to separate metering revenues from distribution revenues, in order to allow the inclusion of more cost drivers (i.e. meter numbers). This type of amendment would provide an automatic adjustment to revenues in response to a change in the relative proportions of the volumes or unit costs of the two services. However, in practice, the effect of such changes would be minimal and runs the risk of creating more problems than it solves.

Ofgem agrees that it is necessary to avoid stranded costs, at least by setting charges equal to modern equivalent asset values. However, such a policy will only be successful if Ofgem applies accelerated depreciation to derive net asset values now and in the future (or allows distributors to charge and retain termination fees), as even the modern equivalent assets will themselves face competition from lower cost alternatives in future because of continuing technical progress. Any simpler policy based on modern equivalent asset values and straight-line depreciation would effectively guarantee that some costs would be stranded, unless distributors are allowed to charge more than the initial estimate of costs.

EDF Energy's response to Ofgem's second DPCR4 consultation: quality of service and other outputs

The future of guaranteed and overall standards of performance

Guaranteed performance standards

Introduction: We are concerned about some of the proposals for reviewing the guaranteed standards. The standards were originally devised to provide a minimum level of service that all customers should be entitled to, recognising the limitations of the distribution system, and to penalise the companies if they failed to meet those standards. However, the continual focus on driving up both the service thresholds and associated penalty payments is effectively exposing companies to greater levels of financial risk, which they can neither practicably nor cost-efficiently manage by increasing investment.

To protect customers' interests, it is vital that in developing the standards an appropriate balance is struck between quality and cost, by setting credible levels of performance that can be efficiently and effectively delivered.

Treatment of severe weather events: There are a number of features with the existing interim severe weather scheme that should be carried forward into a more enduring scheme. In particular**:**

- The scheme is simple for customers to understand.
- The payment to affected customers is not linked to the company's performance.
- The amount of money that companies can recover is linked to their performance, and
- A company's financial exposure is limited in each year.

Given that the majority of companies have no experience of the operation of the current scheme, we believe that the maximum financial exposure should continue to be limited to 1% of revenue a year. Additionally, we believe it is important that companies are only exposed to a single scheme which deals with severe weather events. We believe that such events should be excluded from the IIP scheme and that there is no requirement to have a further network resilience incentive scheme.

The appropriate standards of network construction are defined by the present planning standards. Customers must (and do) expect to suffer occasional outages after severe weather, given what they pay for the network. Expecting occasional outages due to severe weather represents an efficient balance between quality of supply and cost. The actual occurrence of such outages does not provide any grounds for changing that balance, and creating many additional incentives will overstate customers' willingness-to-pay for investment in the network.

A company's incentive to restore supplies after an outage derives from (a) its desire to restore profitable sales of distribution services (which is inherent in the price cap formula) and (b) its liability for compensation payments to the customers who are cut off. In this context, there is one aspect of the current interim scheme that particularly needs to be addressed. The present 48-hour threshold for compensation payments applies whether 2% or 25% of the company's customers have been affected by the severe weather event. This would seem to be illogical, as the damage associated with an event affecting 25% of a company's customers will be substantially greater than that for one which affects 2% of its customers.

So, given the resource availability within distribution companies, it would be unfeasible for a company to restore an event that affected 25% of its customers within the same time period as an event which affects 2% of its customers.

If a company has no prospect of restoring the affected customers within the scheme timescales, then what it faces is effectively a penalty regime where its exposure is determined by a weather lottery. This is clearly inappropriate and certainly needs no reinforcement through a network resilience penalty. The solution, rather than curtailing compensation to customers, may be to regard some proportion of compensation payments as costs which the distributor is entitled to recover.

We believe that further work is required to calibrate the payment threshold so that it is more sensibly dependent on the impact of the severe weather event. The interim scheme uses customer numbers affected and the number of HV faults as a means to trigger payment to customers. However, for the majority of severe weather events it is the extent of damage to the LV network which extends restoration times. Future investment will reduce the susceptibility of the HV network to damage in severe weather and therefore its appropriateness as a trigger mechanism may decrease.

We are exploring whether other factors (such as maximum gust wind-speed) can be used as a trigger mechanism. Such measures may be problematic because of the interaction of other factors (for example, wind direction or leaf cover), but we believe that there is merit in further investigating them.

The introduction of differential service standards for different classes of customer, including priority customers: We believe that this proposal is both undesirable and impracticable, for the following reasons**:**

- **Inequitable treatment of different customer classes:** As the majority of business customers are connected to the LV system and hence are interspersed with domestic customers, this standard may require us to provide generators to some customers affected by a fault but not to others. This is likely to result in increased dissatisfaction for domestic customers, resulting in increased customer complaints. This would increase our costs and also those of both energywatch and Ofgem.

- **Increased liability on distributors:** The Electricity Act 1989 does not require distributors to provide a guaranteed supply. Those customers for whom a secure supply of electricity is essential have the option of paying for an enhanced connection to the network or having own-generation arrangements. Ofgem's current proposals would effectively transfer this responsibility to distribution companies. Therefore, in the event of a failure to provide the generator, we would not only be liable to make compensation payments, if this was a guaranteed standard, but would possibly be exposed to litigation for consequential loss.

In addition, a number of business customers opt for a lower cost and hence lower security connection (i.e. a radial supply rather than a ringed supply). However, over a period of time, some customers often forget that they have opted for a lower security of supply. Thus, in responding to Ofgem's questionnaires, some customers may be asking for better performance than they were originally prepared to pay for, when they did have a choice. Such customers can still choose to upgrade their connection if they are willing to pay the cost. However, spreading the cost of offering higher performance standards would discourage individual customers from making efficient choices, so raising costs and making customers in general worse off.

It should also be remembered that the vast majority of customers are restored within three hours of a high voltage fault. Notwithstanding this, we do try to respond to each customer's individual circumstances during a fault and on some occasions have provided generation. However, this has been on a goodwill basis and as each customer's circumstanceswill be different, we do not believe that we could offer this service on a guaranteed basis.

We believe that it is inappropriate to link penalty payments for business users to their daily transportation charge. If such an approach were taken, it would be consistent to also link penalty payments for domestic customers to their daily transportation charge. For each of our three licensees, this would equate to approximately 13 pence a day. It should be remembered that the purpose of the penalty payment is not to compensate customers for any consequential loss, because the distributors do not offer a guaranteed service. Instead, the penalty is intended to penalise the company for failing to meet minimum service standards, in order to encourage an efficient response <u>by electricity industry standards</u>.

Automatic payments: The making of accurate automatic penalty payments for failures at any voltage level is currently impractical. The models that were developed for IIP are not 100% accurate at any voltage level and were designed to report the totality of performance to specified accuracy levels, not perfrormance at the individual event level. So, if our current systems were to be used to make automatic payments under the standards, there is a risk that we would fail to pay some customers who were due a payment. This would then expose us to another failure under the guaranteed standards and further penalty payments.

Therefore, unless Ofgem is willing for customers to fund additional investment by distributors to improve the accuracy of the connectivity models, we believe that it is impracticable to make automatic payments for those standards which currently require the payment to be claimed.

Exemptions under the standards: The purpose of the exemptions under the guaranteed standards was to provide all distribution companies with protection against events which were outside their control, because penalties only serve a purpose when they provide incentives to which distributors can respond. In other cases, they merely create unnecessary risks to distributors' financial security. The tightening or removal of these exemptions must be considered in conjunction with the desire to maintain the low risk nature of these businesses. Any removal of the exemptions must increase the risk faced by distributors and hence have an impact on the cost of capital.

Ofgem's main concern is that distributors may have applied an unduly wide interpretation of the scope of the exemptions. However, customers can ask Ofgem to determine any case where they believe that a company has inappropriately applied an exemption for determination. We appreciate that the aftermath of the October 2002 storm raised a number of issues about dealing with large numbers of determination requests. However, this is not sufficient reason for all of the current exemptions to be tightened or removed. To inform our understanding of Ofgem's concern, we would be grateful if it would share with us its examples of how distributors may have used the exemption mechanism inappropriately.

Tightening of the voltage complaint standard: We are unaware of any research that demonstrates that customers are dissatisfied with performance under the current standard. Also, given that there is no information on any proposed alternative standard, it is difficult for us to comment on the impact on our three licensees. However, any tightening of voltage standards will entail major investments, for which customers would pay. We are not aware of any evidence that suggests a willingness to pay for such upgrades.

Overall performance standards

Removal of standards: We support removal, where appropriate, of specific overall standards of performance. For example, the existing OS1b overall standard is effectively duplicated by the IIP scheme and could be removed. The general test must be that, if any overall standard is duplicated in another incentive scheme, it should be removed

Reporting: The inclusion of additional reporting is feasible, but providing additional information must be shown to be both relevant to the regulation of distribution businesses and cost effective to gather and report.

Reviewing the IIP scheme

Scope of output measures and financial incentives: We do not think that it is relevant for quality of supply reporting to be disaggregated on a customer-type basis. With the exception of HV customers (who number only a few hundred on each of our licensed networks), the majority of customers are connected to the low voltage network. The design of this system means that the delivered quality of supply will be the same, regardless of customer type. For the same reason, it would also be impracticable to introduce financial incentives on a customer-type basis.

As stated above, the purpose of penalties is not to compensate customers for their consequential loss, but to provide incentives for efficient operation by distributors. Planning methods relate the design of LV investments to the pattern of load flows through a facility, rather than to the type of customer served by it, since those customers may be remote from the facility, or served by multiple infeeds, and so not uniquely defined. As a result, distributors would be unable to respond to incentives related to customer types, and so would be exposed to new and unpredictable risks.

With respect to unmetered customers, discussions are under way with the highway lighting authorities to review the existing charter of service (which is an informal service commitment). In order to ensure that companies are not exposed to double jeopardy, it is vital that there is no overlap of existing and future incentive schemes.

Worst served customers

We agree that the appropriate form of a worst-served customer standard needs further debate. We have consistently stated that having a single-year, multiple-interruption target is inappropriate. In any single year, a proportion of customers will experience a high number of faults from the combination of unrelated, sporadic events. Hence, this definition of worst served customers will change from year to year. Companies cannot invest sensibly to mitigate the effect of such events, and focusing on them could divert attention from the need to address longer-term, endemic network issues.

We believe that a more appropriate standard is**:**

- No customer must experience more than an average of *x* interruptions a year over a five year period.

A standard formulated in these terms would ensure that companies targeted investment at the truly worst-served customers. However, in order to be in a position to implement such a standard, five years of data are required. Given that we have only been collecting data on multiple interruptions for a single year, it may therefore be more appropriate to review inclusion of a multiple interruption measure within the IIP at the next price control.

Form of the IIP incentive scheme

We agree that the quality of supply targets set for distributors must be equally challenging. We support the principle that companies should be able to earn rewards for out-performance in every year of the next price control, as well as face penalties for under-performance. However, we believe that the marginal rewards must be higher than the marginal penalties, because the balance of risk is becoming increasingly asymmetrical.

As the quality of supply improves generally, the impact of a single large scale event (for example, a 132kV outage) may have a significant negative effect on a company's performance. For example, if a 132kV outage affected 100,000 customers in our LPN area, the resulting interruptions per 100 customers are equivalent to approximately 15% of that company's total 2004/05 interruptions target. Such an incident could completely negate all of the quality of supply improvements made by a distributor over a number of years.

Service targets must therefore make allowance for the different impacts to be expected of interruptions at different voltage levels – a set of parameters that varies between networks, depending on how they are configured. Imposing standards based on average effects would expose distributors to a number of large and unnecessary risks to their financial security.

Dealing with annual variability in performance

We believe that both dead-bands and rolling averages, as mechanisms for dealing with annual variability, bring with them a number of negative incentive effects. Under a rolling average mechanism, a single large event at the start of the price control period will affect the reported performance for the rest of the period. So the impact of the company's investments to improve quality of supply will be masked, hence minimising its ability to gain out-performance rewards. This would weaken the incentive properties of the scheme.

In order for a dead-band scheme to offset the impact of annual variability, the bands would need to be quite wide (for SPN, for example, the standard deviation of CML performance over the last five years was approximately six minutes). However, a large deadband area would mean that incremental improvements in quality of supply would be effectively masked, and so the out-performance incentives would also be significantly reduced.

A possible alternative option may be to use a long-term trend to set targets but measure actual annual performance against this trend. The use of a long-term trend to set targets would**:**

- Incorporate some historic annual variability into the target, hence negating the need to have deadbands,
- Maintain strong incentives to out-perform, and
- Be simple to understand and operate.

We are currently investigating the feasibility of such a scheme and would be happy to share our work with Ofgem when it is completed. In addition, we believe that it would be appropriate to settle the outcome of the IIP scheme at each price control rather than have yearly penalties or rewards. Such an approach would contribute to the stability of prices across the period.

Targets, incentive rates, and financial exposure to the scheme

We agree that the total exposure to the incentive scheme must be balanced against customers' willingness to pay and also against the robustness of the information available. With respect to the latter, we are concerned that Ofgem has referred to the outputs of its benchmarking exercise as "indicative" targets. We have consistently stated that the current benchmarking process cannot be used to set targets mechanistically, as it fails to take into account a number of relevant factors including inherited network design. The current process can be used to inform the target-setting process, but not to set future targets mechanistically. To do so would result in targets not being equally challenging across companies, which is clearly inappropriate.

Planned interruptions in final year of the current scheme

We believe that the treatment of planned network interruptions should be left unchanged for the final year of the current scheme. It is unlikely that sufficient detail will be available about the future IIP scheme to understand whether it would be better to defer or advance planned interruptions in order to make short-term financial gains.

The realisation that the current scheme encourages gaming is evidence that the current short-term approach to quality of supply targets encourages companies to make decisions not necessarily aligned with the longer-term operation and maintenance of the network. The incentive scheme should not place greater incentives on companies to defer needed reinforcement or maintenance work, in the expectation of possible short-term financial gain.
It is vital that the scheme is amended to ensure that perverse incentives are not carried forward into the next review period.

Network resilience

We believe that it is important that severe weather events are dealt with under a single incentive scheme. As we have suggested earlier, the current interim scheme for dealing with severe weather events should be appropriately amended and extended into the next price control period. As this scheme directly compensates customers who are affected by the storm, there is no need to have another specific severe weather incentive scheme. It should be remembered that companies are already strongly incentivised to perform efficiently during a severe weather event because of the level of public scrutiny that they are under and the consequent reputational damage if they perform badly

In addition, it would be inappropriate to retain any aspect of a severe weather event within the IIP, as to do so may mean that a company is being penalised twice for the same event. With respect to telephony performance, the inclusion of a severe weather event would weaken the incentives to perform. For example, if a severe weather event occurred at the start of the year, it is highly likely that it would affect the reported performance for the entire year. So companies would be less likely to invest in improving performance, as they would see no benefit. This demonstrates that the inclusion of severe weather events in the IIP telephony scheme would effectively reduce this aspect of the scheme to a weather lottery and therefore damage incentives.

We support the work being undertaken to develop an understanding of the links between weather, the environment, the number of faults experienced, and customer impact as a result of a severe weather event. However, such models are in their infancy and it is likely to take a number of years of data collection to build, test, and refine a model which could be used robustly for all distributors. This may be an area that would benefit from being included within the innovation and incentives programme.

Form of the customer survey

We believe that the performance of distributors in the customer survey has converged to a point where the results are highly volatile. It would therefore seem appropriate for any future scheme to set absolute targets for each company. These targets should be informed both by the willingness to pay survey and the starting position of each company. Also, of course, any future improvement glidepath must be sufficiently funded.

Customer survey bias

We are pleased that Ofgem intends to undertake additional work in this area. We have consistently stated that regional bias exists and must be taken into account in assessing the survey results. In fact, the existence of survey bias should be a strong driver for moving to a scheme that is based on absolute performance. We would like Ofgem to share with us its proposed workplan and would be happy to help to develop its thinking in this area.

Automated messaging

We agree that it would be beneficial if customers who heard an automated message could be included within the survey. However, the data protection issues that existed when the measure was initially implemented still persist. Our service provider is therefore unable to give us the telephone numbers of customers who have heard an automated message. As the technology of telephony develops, it may be possible in the future to appropriately identify these customers, and we therefore suggest that this situation should be reviewed as part of the next price control.

Incentive for the speed of telephone response

We agree that any targets for the speed of telephone response should be on a company specific basis. However, future targets must take account of the starting position of each company, and any assumed rate of improvement over the next price control period must be sufficiently funded.

Combining quality and speed of telephone response

As companies have only been collecting speed of response data against the current RIG definitions for three months, we do not believe that sufficient information exists to understand whether it is both feasible and appropriate to combine these measures. On this basis, we believe that the two measures should be reported separately for the next control period.

Environmental outputs

In principle, we have no objections to Ofgem introducing reporting for certain environmental outputs. However, before this is undertaken Ofgem must ensure that:

- There is a defined purpose for reporting the information,
- It is not already reported by another environmental regulator,
- It is cost effective to gather and report the information, and
- Any changes to information systems are appropriately funded.

We appreciate that Ofgem does not intend to place incentives on any environmental measures and that the intention is to better inform the general public. However, publication of such data allows third parties to use the information to undertake their own analysis and hence draw comparisons across the companies. Therefore, to ensure that all companies are treated fairly, any reporting must be to a predefined set of definitions which all companies are obliged to comply with. This will ensure that reported data are consistent across companies.

EDF Energy's response to Ofgem's second DPCR4 consultation: distributed generation issues

Distributed generation (DG) incentives

Summary

We have consistently supported the need for an appropriate mechanism to incentivise distributors in connecting and operating DG. We are therefore pleased to see the continuing development of such an approach by Ofgem. However, given the profound impact that climate change is expected to bring, we consider that, overall, Ofgem's scheme in its present form places too much risk on distributors and offers little incentive for DG investment.

A scheme designed to provide stronger incentives to distributors to facilitate DG connection would be more likely to further intensify their efforts to increase such connections.

In addition, we feel that there are still some significant issues that need to be resolved before it can be agreed that a wholly workable and acceptable incentive regime has been derived.

The issues include the following:

- The overall rates of return on offer are too low, especially since they depend on the cost of connection and the proportion of expected generation that actually connects.
- Distributors would therefore be subject to major risks surrounding the emergence of unexpected schemes with very high connection costs.
- The proposal does not recognise the treatment of future non-project-specific strategic and overall DG-related costs.
- The level of return is too low to incentivise distributors to invest in preparing networks for DG ahead of the emergence of specific connection requests, and creates the prospect of stranded costs.
- The level of the proposed O&M supplement to the incentive rate is too low to cover the associated costs.
- There are inconsistencies between the scheme and the statutory and related legal framework surrounding connections
- Further work is required on which customer groups are to meet these costs, and on linkages with the structure of charges project.
- Our analysis calls into question the suitability and practicability of the availability incentive.

These points are examined in more detail below.

Overall rates of return

We have looked at the returns from the hybrid scheme as outlined in Ofgem's paper. These exceed 6.5% in some credible scenarios, provided that the reinforcement costs per kW are not much higher than the average £/kW rates that have been used, the anticipated megawattage of DG actually does connect to the system, and there is a suitable treatment of future strategic and overall DG-related costs (see below). However, the risk/reward balance is skewed.

This is because, as projects become more expensive and the proportion of the expected DG that actually connects (and continues to be connected) reduces, the risk increases that the cost of capital will not be covered. Even for a project with an average reinforcement cost of £50/kW, if only 50% of the anticipated generation connects, then distributors will earn a return of less than 6%.

These rates of return are unlikely to be attractive to EDF Energy in view of the associated risks. The issue could be addressed in a number of ways. Possible solutions include, for example, increasing the size of the pass-through element, increasing the incentive rate, both of the previous two suggestions, or providing some other safeguards (some suggestions for these are given below).

Unless a more suitable risk-and-reward balance is produced, by the use of such options, investment will be delayed or avoided. This could have a profound effect on the government's ability to meet its targets for renewable generation.

Moreover, Ofgem has not provided any indication of how the proposed rates of pass-through (70% or 80%) will be achieved, since they differ from the rates calculated for capex in general. Before we can commit to a scheme, or authorise capex on the basis of a scheme, we will need to understand how all its elements work.

Risk mitigation

We appreciate that, since Ofgem's scheme is designed to be simple and fairly easy to apply, and there is a significant degree of averaging involved with it, there will be some low cost schemes where high rates of return are achieved which to some extent balance higher cost schemes. However, even with the amendments to the scheme suggested above, this simple approach continues to leave distributors exposed to the emergence of high cost schemes which require a disproportionate expenditure on projects with low returns.

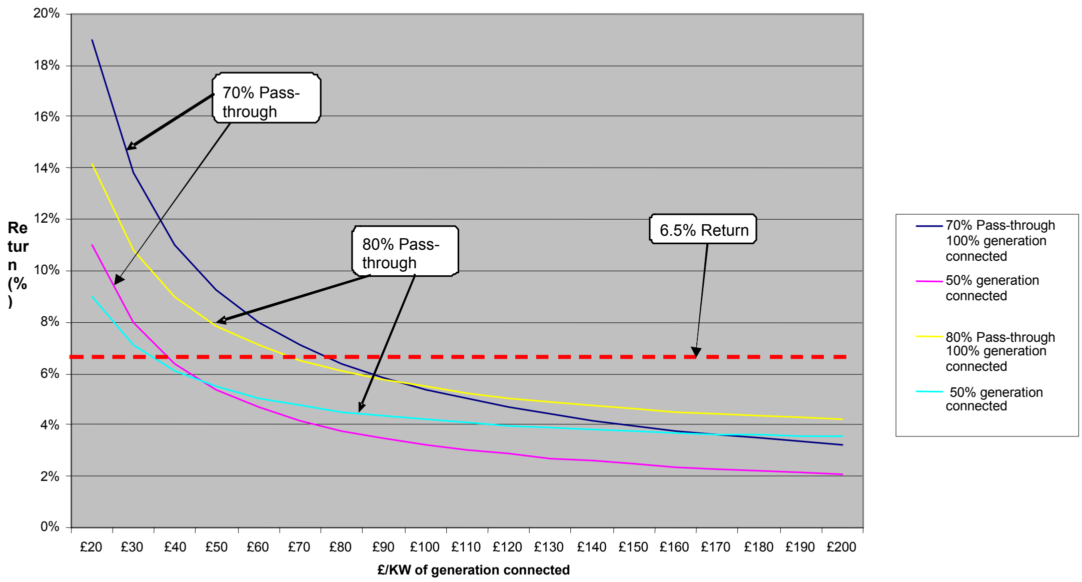
This problem is exacerbated by the considerable uncertainty about the scale, timing, and technology of DG that may be connected to networks. This is illustrated by events that have occurred since we submitted the DG business plan questionnaires last September. The government recently announced progress with the second round of off-shore wind leases. These may well be significantly larger than the schemes in the first round. A number of these second round schemes are located off the coast of the areas where EDF

Energy is the distributor. While we took some account of the potential for such schemes in our September submission, we may well have under-estimated their scale.

For example, if the large schemes off the coast of north Norfolk in the Greater Wash area progress to completion and are connected to the distribution (rather than transmission) network, then very significant costs – well in excess of £30m – could become necessary, with relatively high per KW costs. The potential for such outcomes could substantially distort the overall scheme

The balance between £/kw cost and rate of return is illustrated in the chart below[1]:

Rate of Return – according to cost of connection and Ofgem options



Clearly, there is a serious risk that a limited number of very large/expensive connections will depress overall returns below the regulatory cost of capital. For example, we estimate that connecting wind farms off the coast of north Norfolk could cost at least £30m (see above), having taken account of those costs recovered directly through a "shallow" connection charge. As previously mentioned, this risks distorting the scheme and suggests that projects above a certain size/cost threshold "collar" should fall outside the incentive and be subject to full pass-through (and the normal rate of return).

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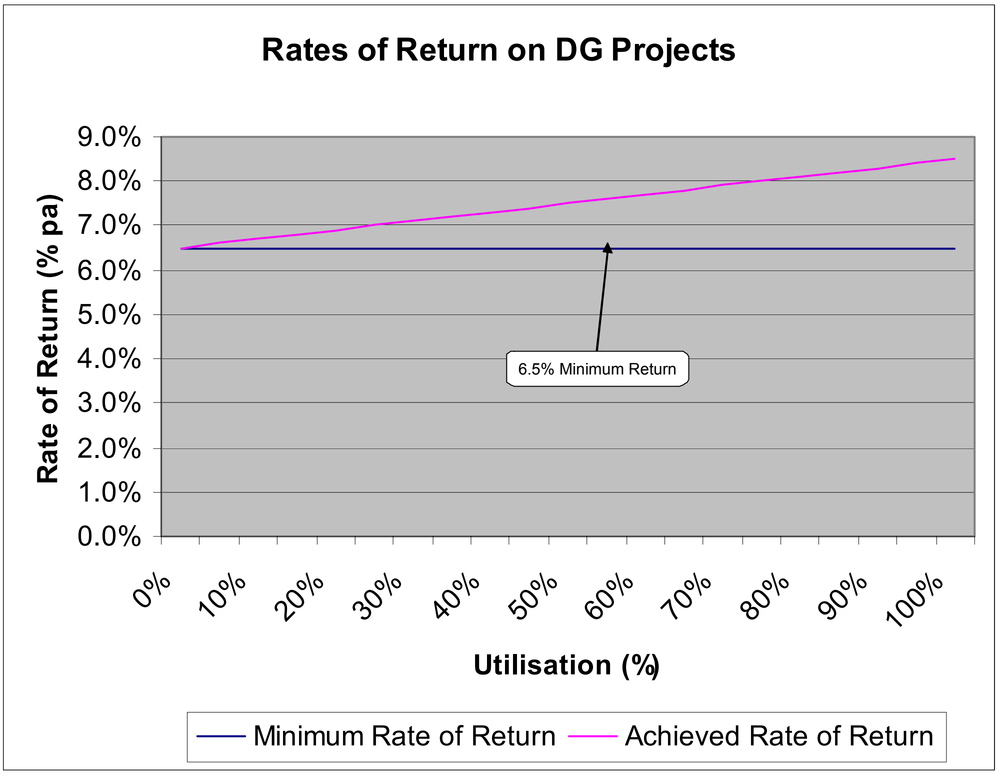
[1] Note that this chart is based on a regulatory asset base approach to the pass-through element of the hybrid scheme rather than the annuity one which seems to have been adopted in Ofgem's paper. While in general the impact of this is relatively limited for cases where no generation actually connects (which determines the minimum return that a distributor would achieve) the returns become 0.87% and 2.85% under the 70% and 80% pass-through options respectively (compared with the minimum rates of 1.4% and 3.2% that are claimed by Ofgem in its paper).

Given the consensus that costs per kW can vary widely between projects, for reasons that have nothing to do with the efficiency of the distributor carrying them out, it is questionable whether rates of return should be exposed to this kind of cost-dependent risk. Such a scheme will not offer incentives for efficiency, but will merely discourage distributors from carrying out (efficient) high cost projects.

An alternative approach might be to accept the difficulty of specifying some kind of automatically defined revenue allowance for projects with widely varying costs. Instead, Ofgem could provide a basic incentive for investment (i.e. a minimum rate of return equal to the cost of capital) and then focus incentives (additional returns) on ensuring that investment is fully utilised.

There are no free lunches and this type of incentive is only available at a real cost – i.e. a slightly higher rate of return. However, if it encourages distributors to focus on projects that are likely to be fully utilised, it will encourage lower costs overall. We can provide examples of such schemes, if required.

The diagram below shows the rate of return that distributors would be allowed to achieve, if they were granted a minimum of 6.5% (i.e. the cost of capital), plus an additional return of (or equivalent to) 0.1% for every 5% of utilisation, such that 100% utilisation would add 2% to the allowed rate of return. This additional return would give distributors an incentive to focus on projects likely to be of value. Although higher utilisation would give higher returns, it would also cut the charge per unit. For example, raising the rate of utilisation from 60% to 80% would cut the charge per connected kW by more than 20%, despite the higher rate of return. So it is clearly possible for connected



customers to benefit from incentives offered to distributors. Many schemes of this type are possible and EDF Energy would be willing to discuss different options with Ofgem.

<u>Future non-project specific strategic and overall DG-related costs</u>

We are also concerned about the treatment of future non-project-specific strategic and overall DG-related costs (as shown in Table 13 of the September submissions). We are unclear about the intended treatment of these costs. If they are not treated as eligible for the pass-through element of the hybrid mechanism or covered elsewhere within the framework, then there would be a significant impact on the overall return that a distributor would obtain from the investment necessary to connect additional DG.

Our modelling indicates that, based on the September information and without such pass-through or other treatment, returns for each of the three distributors in EDF Energy's area would be below (and in some cases well below) 6.5% even if all the expected generation is connected.

This arises because the items that we included in this category are very varied and may not be easily treated as pass-through. They include both operating costs and capital expenditure, <u>but do not cover cases</u> where networks are being speculatively prepared for DG ahead of the emergence of specific connection requests. Examples of the higher costs are changed business processes to manage faults, more complex network control arrangements, switchgear replacement and reinforcement resulting from the incremental effects of DG, additional planning costs, and billing and registration costs arising from the introduction of generator use of system charges.

It would be useful if Ofgem would clarify how these costs are being treated:

- Is it intended that they would be pass-through and if so how would this work for operating costs, or
- Are they being included in the incentive rate (see also the section on O&M costs below), or
- Is some other allowance being made within the price control framework?

<u>"Strategic" investments</u>

In paragraph 5.34, Ofgem's paper explores the type of incentives necessary for distributors to make "strategic" investments ahead of need in order to facilitate DG. It is important to recognise that any such investment will be competing with all other potential investments throughout the EDF Energy Group – therefore covering both regulated and unregulated businesses and a number of international markets – and so will need to have the potential to achieve a rate of return which is attractive in relation to such other investments, taking account of the risk profile (which is not likely to be low as it will be at least partially dependent on the actual full materialisation of the expected DG).

Taking account of the risk of the non-emergence of generation in such a case, our modelling indicates that the costs of connection would need to be lower than about £35/KW in Option B to achieve a 6.5% rate of return should only 50% of the expected generation actually connect to the network. In order to make a return of say 9%, connection costs under this option would have to be lower than £20/KW.

We feel that this is unlikely to be sufficient to encourage distributors to make such investments. Thus, we are supportive of the need for the incentive to distributors to manage such incentive risks to be increased. This could be done by increasing the incentive rate within the hybrid mechanism, though it should of course be recognised that, since this is itself dependent on the amount of generation that is connected, such an increase would need to be quite significant.

Treatment of O&M costs

It is important to clarify which costs are intended to be covered by the proposed supplement to the incentive rate for O&M costs. Is it limited to O&M costs for shared assets, or is it also intended to cover:

- O&M costs for the associated sole user assets (in view of the intention to remove such costs from connection charges) and
- Non-project-specific operating costs which will arise from a greater penetration of DG?

If the O&M element is not intended to cover such costs, we would welcome clarity on where within the price control regime such additional incremental costs are being covered.

Additionally the assessment of £0.5/kW to £1/kW for O&M costs seems to be based on a view of existing proportions of such costs. We believe that this range should be increased to a somewhat higher level and that the actual figure used needs to take account of the fact that this range is an average and that generation connections are likely to be complex to operate and maintain. We believe that these various factors mean that a substantial increase in the O&M component is required unless these additional costs are being covered elsewhere.

Paragraph 5.27 of Ofgem's paper states that pass-through does not include general corporate overheads or capitalised O&M – which would be "covered elsewhere". It is assumed that as far as O&M is concerned this means the proposed O&M supplement. However, it would be useful if Ofgem could clarify that this is the case and also indicate how the overheads referred to will in fact could be handled.

Legal aspects

We have previously referred to the need to ensure that a hybrid incentive scheme is soundly based on the legal and regulatory structure for connection. To be more specific, how does such a scheme relate to section 19(1) of the Electricity Act – which permits distributors to recover their reasonable costs in respect of individual section 16A applications?

Section 19(1) seems to permit a distributor to fully recover the costs of a high cost connection, if reasonable, even where its costs exceed those allowed under the scheme (i.e. the pass-through percentage plus the £/KW incentive rate is less than the costs of connection). Conversely where the costs of connection are low (i.e. the pass-through percentage plus the £/KW incentive rate is more than the costs of connection), the person seeking the connection might challenge the charges resulting from application of a formula based on average costs.

The scheme may in fact therefore be inconsistent with the law as it stands at the moment in relation to connections. It will be vital to get clarity on the legal standing of the scheme, as cost recovery is dependent on the longevity of the arrangements – which could be in excess of 15 years.

Connections for both demand and generation

Given that many connections (notably those associated with CHP schemes) will be for both demand and DG purposes, the hybrid scheme will need to be specific on the allocation of capital expenditure between these two aspects.

This is important,since that expenditure which is allocated to demand will be subject to effectively a full pass-through regime, while that which is allocated to generation will be subject to partial pass-through plus an incentive rate arrangement. Such clarity will be important to avoid future disputes and to ensure that sufficient information is available to allow distributors to fully assess the overall acceptability of the scheme.

Stranded costs

In order that we can understand the risks that we are being asked to bear with the hybrid scheme, it is important to understand what happens if a generator ceases production or even, in an extreme case, goes into bankruptcy and closes down. Do the respective incentive £/kW payments cease – effectively leading to the emergence of some stranded costs that cannot be recovered – or are they spread (through generator use of system charges) over the DG community or potentially even among all connectees?

A possible route to understanding these issues would be to establish the point of time at which the £/MW flow commences and at which it ends. We believe that the former of these should be as early as possible in the connection investment process and before any substantial distributor investment has been incurred. An appropriate point could be the signing of the generator connection agreement, as this represents a commitment from the generator. As far as the end point is concerned, our view is that once the MW have been counted for the incentive arrangements, they should stay for the full 15 years, irrespective of the continuation of the actual generation schemes. This would avoid the risk of distributors being left with stranded assets and facing an exposure similar to that affecting the DG itself.

Where do the various DG costs fall?

Effectively, Ofgem's paper seeks to indicate a potential incentive-based mechanism for assessing the revenue entitlement that arises from those DG costs incurred by a distributor that are not covered in connection charges or otherwise. However it is not clear to whom such costs would be charged. To what extent would they be matched to individual generators, to classes of generators, or be shared with demand customers?

This is an issue that is perhaps being picked up by the structure of charges project, but again it will be necessary to understand the proposed approach so that any mismatches or risks can be fully understood. A possible approach (at least in the short term) would be to have site-specific generator use of system charges for EHV sites, and generic charges for generators connected at lower voltages, perhaps with some elements of the costs shared with demand customers.

This latter point would be particularly important should there be a desire to cap the level of generator charges where increasing numbers of generator connections are leading to a significant increase of costs that would lead to a large degree of volatility in the level of generator use of system charges if these were uncapped. In such circumstances, it would not be acceptable to EDF Energy for there not to be a route for such costs to be recovered, and this may most effectively be done be charging such costs to demand customers

Availability incentive

Ofgem's paragraph 5.34 also explores the possibility of an availability incentive. While the desire to have such an arrangement is understandable, the existing proposals do not seem to be acceptable. There are many issues that still need to be assessed and resolved. These include:

- The relationship with other forms of "compensation", such as contractual liabilities, guaranteed service standards, and the IIP scheme, so that the overall impact of particular events can be assessed.

- The nature of the formal cost recovery or incentive mechanism that should be associated with such a scheme. There needs to be the prospect of some upside or otherwise it will be a systemic risk that merely increases the cost of capital.

- The need to exempt existing schemes with weak connection arrangements from the scheme

General clarifications

Some further practicalities need also to be understood. Questions requiring answers include, for example:

- What are the cost implications of running the hybrid scheme, and

- How is the necessary information to operate the scheme to be collected and maintained?

The potential scale of investment in the network that will be needed to facilitate generation connections means that consideration needs to be given to the time period over which such investment is recovered. Options range from 15 or 20 years to some form of "repex" arrangement where the costs are recovered broadly in line with when they are incurred. In order to reduce the stress that such investments – the scale of which are difficult to forecast – may cause to distributor balance sheets, and to minimise any regulatory risk that may arise from the recovery of such costs over very long-term timescales, we suggest that cost recovery should be over the shortest possible time period broadly in line with when such costs are incurred.

We are also conscious of the regulatory risk that changes to the connection charge boundary could have. Such changes could have a considerable impact on the economics of the proposed incentive scheme. Since cost recovery may be over an extended time period, it will be the more important that distributors have sufficient comfort that returns will not be undermined by future amendments to such boundaries.

Innovation Funding Incentive (IFI)

We think that the IFI, if properly structured, may be a very useful mechanism to encourage distributors to give greater emphasis to the development work required to bring about network transformation. There is a clear need for such an approach, as there are currently weak incentives to invest in or take the risks inevitably linked to such innovation. This difficulty is exacerbated by the extended periods that can sometimes be involved in taking an idea through the development process to implementation.

We believe that such innovation can facilitate network transformation, hence bringing forward such customer benefits as:

- Meeting future customer expectations as to the reliability, resilience, and cost of the network,

- Identifying smarter ways to renew networks,

- Aiding the connection of larger amounts of distributed energy resources to distributor networks,

- Contributing to reducing the impact that distributors may have on the environment, and

- Improving the safety and risk management of complex systems

We have previously contended that the IFI scheme needs to be appropriately placed in the overall innovation process, which, we believe, flows through from a business need to the understanding of a potential solution and on to the development of prototypes and field trials, before culminating with large scale process trials and evaluation and finally commercial roll-out.

We are therefore pleased to see that Ofgem has recognised the importance of distributor involvement at all stages of the development cycle, by proposing to extend the scheme to the three categories of research outlined in the July discussion paper on innovation.

We are also pleased to see that the new paper considers higher pass-through proportions than previously, by suggesting 90% in the first year, reducing in equal steps to 70% in the final year of the price control period. While these suggested changes are welcome, however, we are still of the view that there is a need to further increase the pass-through proportions. The reasons for this are as follows:

- There is a mismatch between Ofgem's desire that the results emerging from this investment in innovation should be rapidly shared among all distributors, and the share of the investment that they are themselves expected to contribute.

- Current distributor investment levels in innovation (as shown in Ofgem's paragraph 5.48) are low and there is a need to kick-start the process.

- There will be a need for a sustained period of investment in innovation if the future benefits are to be delivered.

Therefore, if the intention is that the results of such innovation should be shared and the need for sustained investment at a significantly higher level than currently is recognised, then we believe that the pass-through level should be maintained at the 100% level throughout the forthcoming price control period. This would provide a suitable kick-start to this process, the results of which could be assessed as part of the next following price control review.

We also believe that it is important that Ofgem recognises that distributors' own costs need to be covered by the scheme. Examples of the tasks that will need to be undertaken include:

- The identification of the original business need and the nurturing of the idea to address the problem,
- Project management,
- The development of the safety case,
- The establishment of suitable trials,
- Implementation, and
- Review

All this will require the use of distributor resources in excess of the limited amounts that are currently dedicated to innovation. However, we recognise that there could be some concern if too much of the IFI activity were allocated to these tasks, so we propose that expenditure on them should be limited to 15% of the total resource.

In order to successfully take forward these initiatives and obtain the potential customer benefits, we believe that an annual expenditure in line with an R&D intensity of 0.5% – as was suggested in Ofgem's July discussion paper and is now repeated in the current price control paper – would be appropriate. The potential customer benefits that we have outlined indicate that this investment would over the whole programme be cost effective for customers, although it is necessary to recognise that it is in the nature of such activity that not every project will be successful.

Registered Power Zones (RPZs)

We continue to be broadly supportive of the RPZ concept. However, we share Ofgem's view that a number of important questions remain to be resolved in regard to this. While there is an over-arching need for this initiative to be able to show that it is delivering customer benefit by encouraging the development of more cost efficient ways of connecting and operating distributed generation, care must be taken to develop a regime that is relatively simple to understand, can be cost effectively run, and provides sufficient incentive to distributors to develop, bring forward, and implement suitable demonstration projects.

Using those points as guidance, EDF Energy believes that:

- The RPZ scheme should be relatively simple and this is probably best achieved by having a single category for suitable projects.
- There are likely to be risks associated with such projects. By definition, they are going to be leading-edge projects and therefore subject to significant technology risk. In addition, Ofgem's paragraph 5.69 implies that in most cases the distributor would be expected to shoulder the exposure to potential IIP and guaranteed service penalties. There

is therefore a significant likelihood that, however well managed, the costs could exceed those expected. We do not feel that the current proposed structure or level of incentive would be sufficient to prompt action. As we have previously argued, an incentive which is entirely based on the capacity of DG connected may well be weak if it is likely to be preferable to initially trial innovative solutions on a small-scale before seeking to extend their size and scope.

- We continue to be concerned about Ofgem's desire to set a cap on the costs of the RPZ mechanism. This seems to be an unnecessary and arbitrary constraint which is unnecessary in view of the other safeguards within the scheme. At this stage, it is also not clear what projects may come forward and thus such a cap could frustrate a suitable project with large customer benefits merely because of an artificial limit

- While the attractions of the establishment of an independent expert advisory panel are understood, this may well take a significant effort to both set-up and operate. It may also be difficult to identify many organisations that are both wholly independent and also able and competent to contribute to such a panel. Distributors are likely to be discouraged from taking forward projects if a complex, bureaucratic, unwieldy, and uncertain review and approval process emerges.

Proposal: network innovation zones

We are conscious that the RPZ concept is based on innovation focused on DG. However, it is our view that this should be extended as soon as possible so that it also covers the large-scale trials that will be need to take forward the innovative ideas emerging from the IFI process. We are concerned that otherwise there will be a gap between such innovative ideas and commercial roll-out. This will inhibit the implementation of the innovation.

A Network Innovation Zone – which we recognise would need to be structured and incentivised in a different way than RPZ – would be a way of addressing this gap. We have previously explained details of this idea to Ofgem and will not elaborate them here.

EDF Energy's response to Ofgem's second DPCR4 consultation: assessing costs

Publication of data

Ofgem notes that some distributors "have objected on almost every occasion that Ofgem has proposed to publish financial information". Ofgem should have added, in our view, that such resistance is often driven by concerns about data quality and the associated risk that uncorrected data could mislead less sophisticated users. EDF Energy remains committed to a transparent price control process, provided that it is based on cost information compiled by agreed and comparable processes.

Cost benchmarking

Ofgem has described three key principles for its benchmarking analysis: they are comparability, explanatory power, and consistency. We would comment as follows:

Comparability: Clearly, this is essential for benchmarking to produce robust results. But there must be sufficient transparency in the data (and particularly in Ofgem's adjustments) for distributors to confirm that comparability has indeed been achieved. In other words, what is required is demonstrable comparability. It is now clear that many of Ofgem's "standardisation" adjustments which underpinned the benchmarking used in the last review were not robust: for example (a) the adjustment of faults costs was only partial for some companies, and (b) companies included different levels of pension costs – which were not adjusted for. Lack of demonstrable comparability flowing from implausible cost normalisation adjustments is a major concern of EDF Energy (and, we presume, of Ofgem).

Explanatory power: In describing this principle, Ofgem refers to reliance on "intuitive" factors rather than on abstract variables that "happen to provide the best fit to the data". Such an approach seems to imply a lack of verifiable objectivity, which we would regard as inappropriate. The arbitrary and unsubstantiated assertion of benchmarking parameters during the last price control review (for example, forced y-axis intercepts for fixed costs, and arbitrary weights applied to cost-drivers) did not provide a sound basis for assessing costs.

Such approaches should have no place in the current review. We agree that any cost drivers should have an intuitive explanation, but equally any intuition should be checked against and supported by objective analysis. We would therefore wish Ofgem to add a principle that benchmarking must meet certain standards of objectivity.

Consistency: We support Ofgem's attachment to this principle.

Ofgem has not made any strong commitments to a benchmarking method and may see it as a pragmatic, iterative process intended to inform higher-level decisions on costs, rather than to explicitly determine the setting of a revenue allowance. However, we would be very concerned if Ofgem became committed to any particular analysis, even if it lacks robustness, and tried to use it mechanically in a way that the quality of the data would not merit.

We remain strongly of the view that the data and understanding of cost drivers available for this review are simply not robust enough for Ofgem to contemplate using a frontier approach. In particular:

- Distributor data sets are too small to allow robust statistical analysis.
- Adding international comparators will require the addition of more explanatory variables and may not increase the robustness of results (especially under the DEA approach).
- Any benchmarking may omit key variables, so that deviations from the benchmark can never be identified with inefficiency alone.
- Rates of return based on average stock market performance are only consistent with average levels of efficiency.
- Setting cost allowances to frontier levels can spread higher risk management approaches to all companies (i.e. it can force cost reduction for its own sake, rather than efficiency improvements)
- Using (multi-year) panel data does not increase the number of independent observations, which undermines the use of statistical tests to check for robustness.
- Benchmarking total expenditure (opex and capex) will produce results that are more vulnerable to year-on-year random fluctuations and accounting changes than benchmarking of costs (opex + depreciation + return).

It is manifestly clear that distributors' regulatory accounts do not provide data that are comparable, even after several attempts to adjust them. An average cost approach using all of the data, although itself not without the risk of significant error, would at least be safer than trying to establish frontiers from a subset of the data.

CEPA's productivity study

Ofgem's paper invites comments on the CEPA total factor productivity (TFP) study. National Economic Research Associates (NERA) have examined this study on our behalf and their comments are set out in the attached report. We fully endorse NERA's views, the key points of which are as follows.

The use of TFP analysis is a step forward in calculating X factors, because it provides an objective analytical basis for setting the future cost reduction targets. But NERA's critique of the CEPA study has highlighted a number of fundamental problems with this work. The main issues are these:

- CEPA uses cost data directly from the regulatory accounts that are not a reliable basis for estimating TFP.

- CEPA's methodology is non-standard and, hence, sufficiently subjective to allow Ofgem wide leeway to interpret the results quite differently from CEPA.

- CEPA tries to limit the applicability of the TFP estimate and to suggest a need for additional X-factors associated with catch-up, even though the estimation of X-factors does not require this additional factor and there is no objective basis for measuring it.

The consequence of these issues is that CEPA's own method appears to over-estimate TFP growth and therefore is too unreliable for direct use in setting X factors. Some of the other studies that CEPA uses to form its eventual view suffer from the same problems. We therefore suggest that Ofgem should limit any reliance on the CEPA study to those elements that do not fall foul of the criticisms listed above or, alternatively, commission new work to overcome these problems.

<u>Treatment of mergers</u>

Paragraph 6.75 of its paper seems to suggest that Ofgem is considering a move away from the previous merger policy, stated in the DPCR3 final proposals document of December 1999, and applied to all mergers before June 2002. We are unclear how the current merger policy will be applied retrospectively and therefore we require further detail on its practical application before we can suitably comment.

We are also confused by Ofgem's description of the £32m revenue reduction associated with the current merger policy. Our initial understanding, based on previous communication with Ofgem, was that the £32m represents a one-off reduction in revenue, spread over five years, and bears no relation to any expected level of savings. However, the implication in the current consultation document is that the £32m equates to the forecast merger savings.

If this is the case, Ofgem will have recovered the savings in advance of them being achieved by the company. We believe that Ofgem must clearly set out how its current merger policy applies to those companies who have merged since its implementation.

Irrespective of which policy is applied we believe there are two overarching principles that must be maintained in assessing the treatment of mergers. They are these**:**

- Companies must be allowed to maintain an appropriate share of any merger efficiency savings. Our view is that a company must be allowed to retain the <u>net benefits</u> of any merger for at least five years. This would imply that the merger savings from EDF Energy's Seeboard acquisition should not be passed to customers before the start of the next (i.e. DPCR5) period.

- Merger savings achieved to date by EDF Energy, or by other companies, must in no circumstances be double counted as a consequence of the cost assessment process.

RAV roll-forward

This issue lies at the heart of our concerns about Ofgem's potential use of a flawed benchmarking analysis.

At the last review, Ofgem/PKF made adjustments to the costs in an attempt to remove accounting and other differences in order to improve inter-distributor comparability of cost data. It has since become clear that the robustness of these adjustments differed between the distributors. Ofgem may suspect that this is because distributors did not provide PKF with the information needed to perform this task – and on this basis may believe that there is no case for the inclusion of capitalised cable fault costs in the roll forward of RAV values.

However, such an assertion would be unfair. Distributors provided information to PKF in line with their understanding of the questions being posed. The fact that these interpretations differed between the companies is not surprising, since Ofgem had not then (and has still not) put in place a robust set of regulatory accounting guidelines to act as a point of reference on which to develop a mutual understanding.

Against that background, to deny the recovery of efficiently incurred costs would be unacceptable.

Our prime concern with regard to the RAV roll-forward is that the methodology applied should result in the allowance of efficiently incurred expenditure over the whole of the current price control period. We believe the only acceptable outcome in this area is for Ofgem's approach to ensure that all legitimate costs relating to activities undertaken by the distributors during this period are fully funded and that customers pay once, and once only, for the efficient services that they have received. This is entirely consistent with Ofgem's opening paragraph in the RAV roll-forward section of its paper.

On this basis, Ofgem's assertion later in the paper that "all cable and overhead line repair costs ('fault costs') incurred [during the DPCR3 period] would not be included in the RAV", and that this "represents a consistent application of the method used in DPCR3", cannot be supported. This is because, for each of our three distribution companies, the costs relating to replacement after faults were left in capex following the PKF normalisation adjustments.

It is our understanding that this is a common and contentious issue for the majority of distributors.

Ofgem's proposal to disallow all fault-related costs from capex (and therefore from the RAV), including the cost of replacement following a fault, means that each of our three distribution companies (as well as some of the other UK distribution companies) has effectively incurred a cash cost in the current price control period that was not funded through either allowed opex or capex.

We strongly believe that the fact that only a small minority of the distributors ended up with a PKF adjustment that removed all fault-related expenditure from capex confirms that Ofgem cannot reasonably assert that there was clarity across companies on what the adjustments were seeking to achieve. It is apparent that some companies believed that they were trying to move all fault-related expenditure into opex, that some believed that they were trying to normalise fault accounting policies back to the 1994/5 position, and that still others believed that they were trying to normalise the repair element of fault costs into opex while leaving replacement costs following a fault in capex.

All we seek to achieve in this area is the ability to continue capitalising fault costs on the same basis as was the case in 1997/8 after taking account of the PKF adjustments. This would ensure that these costs are funded once, and once opnly, through capex as they are not in our companies' allowed opex.

Ofgem raises the point in its paper that some distributors have changed their accounting policies since 1997/8, so that they now capitalise a greater proportion of fault costs than they used to. In these circumstances, we would support the principle that additional capitalisation relating to these changes should not be included in the RAV, as this would result in those companies effectively being funded twice for the same expenditure. We have provided Ofgem with evidence that the accounting policies employed by our three distribution companies left fault replacement-related expenditure in capex in 1997/8. Our proposed solution to this area is that during the DPCR3 period we should continue to include, within the capex being added to the RAV, the same proportion of overall fault costs as at that earlier time.

EDF Energy's response to Ofgem's second DPCR4 consultation: financial issues

The financial ring fence

Ofgem proposes to exert a degree of control over cash distributions made by distributors in circumstances where a marked deterioration in credit rating has occurred. The mechanism would only become active once a predefined trigger had been reached. Ofgem has set out three options in relation to the level of the trigger, including: loss of investment grade rating, evidence of a potential downgrade to loss of investment grade rating, and downgrade to the minimum investment grade rating.

This proposed regime may reduce the perceived riskiness of debt, so reducing the cost of debt, but it may also increase the perceived riskiness of equity (and hence the cost of equity), which would create an incentive for higher gearing levels. The introduction of such a new regime may also increase perceptions of regulatory risk, which would raise the cost of capital generally.

A cash lock-up is a heavy-handed device which should only be invoked in the most extreme circumstances. There are market mechanisms already in place for restricting cash distributions, for example via debt covenants. (There is an increasing trend towards the use of debt covenants for debt:RAV gearings above 60–65%.)

The proposed trigger points may be reached reasonably often, and are not necessarily linked to bankruptcy, which corresponds to a D grade credit rating, several grades below investment grade. A company that falls below investment grade but remains solvent may still have access to the junk bond market, which can generally provide for its short-term debt requirements (at least).

To avoid unnecessary rigidities in financing arrangements, we believe that the cash lock-up mechanism should only be invoked when insolvency is imminent: as evidenced, for example, by an actual downgrade below B– into any C grade credit rating.

Cost of capital proposals

Ofgem's paper sets out a number of proposals for changing the method of calculating the weighted average cost of capital (WACC). As drafted, the proposals contain errors and provide substantial room for inconsistent use of discretion.

General method: Ofgem is interested in using the "aggregate return on equity approach" proposed by Smithers & Co "alongside" the CAPM approach. We have a number of concerns about the use of the return on equity approach. These are supported by our advisers, NERA.

The concerns are as follows:

- The approach is only valid when equity betas are close to one. As NERA has argued in previous submissions we have sent to Ofgem, equity betas may well be higher than one for highly geared firms[2] and will simply provide inaccurate estimates for the majority of distributors. Therefore, the method does not "solve the ERP puzzle", as Ofgem claims, but merely hides a strong assumption about equity betas.

- The use of two measures is not transparent. While the use of measures such as the discount growth model is sensible as a cross-check, Ofgem proposes to weight the aggregate return on equity and CAPM according to the "robustness of the estimates" (i.e. to use the return on equity approach when equity betas are close to one). This is non-transparent and creates regulatory uncertainty. To avoid such uncertainty, Ofgem should calculate the cost of capital in terms of at least one standard method (for example, CAPM) and should use other methods as a cross-check on the answer. Using one method for calculation purposes imposes a necessary degree of consistency**:** the cross-checks can be used to calibrate the parameters within the method.

- The approach uses a mix of historic returns (for total equity returns) and forward-looking data (for the risk free rate). As discussed in the next sub-section, estimates of the WACC based on a mix of historical and current data are internally inconsistent and susceptible to bias.

- The allegations of "flaws" in the CAPM, which are used in the original paper by Smithers & Co to justify reformulation of the CAPM, are weak[3]. CAPM has survived the test of time and is the most widely used approach in practice. All methods of calculating the cost of capital have problems and it would be futile to abandon CAPM in a search for perfection. The advantage of CAPM is that it provides a transparent consistency check and a stable procedure (though using any other standard method would provide the same benefits if Ofgem applied it consistently).

Overall, we believe that Ofgem should follow a stable, formulaic approach that adheres to principles of transparency and internal consistency and minimises regulatory risk. NERA considers that, for the reasons described above, the aggregate return on equity approach and the use of ad hoc survey data fail to satisfy these principles.

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[2] *Ofgem's initial proposals for the cost of capital in the distribution price control review: A report for EDF Energy* (NERA, August 2003), paragraph 2.14. As stated in that report (footnote 9): "Ofgem used an equity beta of 1.0 in the 2000 distribution price control review based on a 50:50 debt:equity structure. An assumption of higher gearing than 50:50 [as currently proposed by Ofgem (see discussion below)] would then imply a beta greater than one and a return on equity higher than the aggregate market return".

[3] These "flaws" relate to an allegation that investors have under-estimated inflation over long periods of time. NERA refuted this allegation in its previous submission, *Ofgem's initial proposals for the cost of capital in the distribution price control review: A report for EDF Energy* (NERA, August 2003), paragraph 2.17.

Use of forward-looking data: Ofgem says that it intends to use forward-looking (current) data wherever possible: "Where possible, Ofgem will focus on forward-looking (or most recent) market information, though it recognises that, at least for the ERP, a longer time-frame will need to be considered".

In this context, we have supported the views of NERA in earlier papers sent to Ofgem. However, Ofgem has misquoted those views. Ofgem states:

"[NERA] argues that Ofgem should use the long-term average of an historical time series. [NERA's] report also argues that, given current market volatility, the use of historic data could under-estimate the forward-looking cost of equity".

This is an incorrect characterisation of NERA's submission and NERA will be writing directly to Ofgem to point out the error, since the two sentences quoted above suggest that NERA provided inconsistent advice. NERA did <u>not</u> argue that the problem lies in the use of historic data: it argued that the problem lies only in the use of <u>recent</u> historic data. Our view was that long-term time series should be used to overcome any potential biases due to recent market volatility or temporary structural factors. For example:

- Real risk-free rates have fallen since 1998 while also becoming more volatile. This is at least partly due to temporary increases in demand as a result of minimum funding requirements and accounting (FRS17) requirements. Long-term estimates of the real risk-free rate, consistent with the long-term equity premium, are around 3%.

- Recent falls in beta reflect transitory stock market events, not sectoral trends (see the diagram on the next page). In particular:

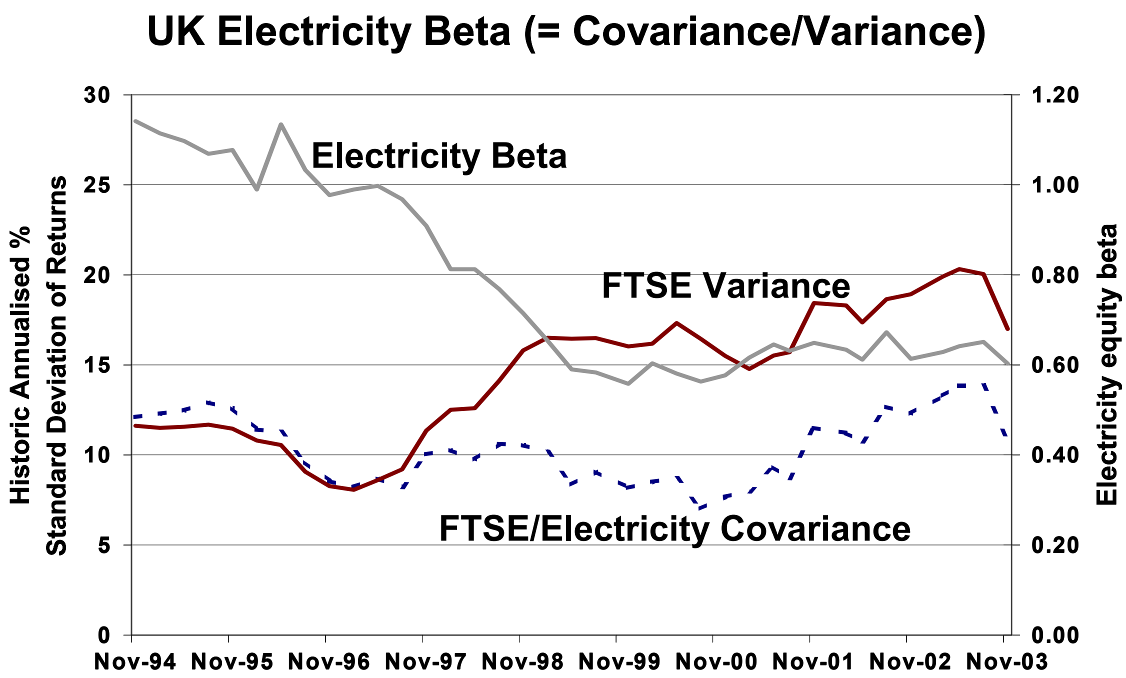
    - the fall in beta reflects a continuing rise in stock market variance due to increased global uncertainty, the stock market crash, and the war in Iraq,

    - the co-variance of electricity stocks and the FTSE rose after the last review to pre-1998 trend levels, and

    - expectations of a lower beta imply a continuation of stock market volatility.

We also consider that mixing historical data and spot-price data is internally inconsistent and can cause biases due to the inverse relationship between the equity risk premium (ERP) and the cost of debt. In times of high market volatility, ERP rises to reflect higher required equity returns, but yields on risk-free assets and the cost of strong corporate debt fall as investors reallocate their portfolios towards less risky government and corporate bonds. So, combining historical data for the ERP with spot-price data for the cost of debt will produce inconsistent estimates of the cost of debt and equity and a biased (under-) estimate of the overall cost of capital.

Diagram (see second bullet on previous page): Constituent Parts of Equity Betas for the Electricity Sector



For all these reasons, we believe that forward-looking CAPM parameters should be estimated as <u>long-term</u> historical averages of the relevant time series, rather than by reference to current spot-levels.

Ofgem is currently proposing to use a combination of longer term ERP and the most recent market information for other factors, despite having been informed that this process is inconsistent and biased.

Cost of historic debt: Ofgem proposes to make no adjustment for historic debt costs. Its paper says**:**

"Ofgem indicated in the July document that it did not intend to make adjustment for the cost of historic debt **...** Ofgem will estimate the cost of capital based on an efficiently financed company **…** In Ofgem's view, an efficiently financed company is one that takes a balanced approach to the management of its borrowings, which diversifies its risks cost-effectively (especially its refinancing, interest rate, inflation, and duration risks) and which aims at achieving a broadly stable real interest cost over time".

Previously, Ofgem justified its refusal to accommodate embedded debt costs on the basis that real interest rates have recently been stable. It appears that Ofgem no longer holds this view of recent interest rates[4]. Instead, Ofgem now relies on an argument that firms operating efficiently should have taken steps to mitigate the effects of any movements in interest rates or the cost of debt.

Ofgem claims that "consumers should only have to pay for efficient financing costs incurred by companies". However, even an efficient firm with a diversified debt maturity profile (as required for higher rating levels by credit agencies) will incur ex-ante hedging costs or, if real interest rates should fall, ex-post refinancing costs and/or a higher cost of debt. Ofgem should make allowance for the effect of falling real interest rates on an efficient, diversified debt portfolio, either through an adjustment to long-term average interest rates, or through an explicit adjustment for refinancing costs.

Pre-tax or post-tax approach: Ofgem proposes to switch from a pre-tax approach to a post-tax approach. This entails a different treatment of the allowance for tax. Ofgem's proposals raise number of concerns and offer a number of choices**:**

- **Gearing and the level of the allowance for tax:** Ofgem is proposing to calculate a tax allowance based on the higher of (1) the company's actual gearing or (2) Ofgem's assumed "optimal gearing". Assuming that higher gearing lowers tax, this rule means that the allowance for companies with gearing (debt**:**RAV) less than Ofgem's optimal level will not cover the whole of their tax costs. On the other hand, companies with gearing above Ofgem's optimal level will only receive an allowance equal to their expected costs.

This rule offers complex incentives. Companies with lower gearing than Ofgem's optimum will not recover the full cost of tax, but may have a lower (post-tax) cost of capital than Ofgem allows**:** the net effect is ambiguous.[5]

However, companies with higher gearing than Ofgem's optimum will pass through their (lower) tax costs, but Ofgem will not recognise their higher post-tax cost of capital, and so they will be penalised.

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[4] In December 2003, NERA gave a presentation to Ofgem which showed that real interest rates have in fact fallen by approximately 58% since November 1998, and by 65% since June 2000. Volatility has also increased, with the risk free rate (as represented by real yields on index-linked gilts) varying between 1.7% and 2.5% since 1999. See *Distribution price control review 2005: Regulatory principles and financial issues* (NERA, 3 December 2003).

[5] The Modigliani-Miller rule about the weighted average cost of capital being unaffected by gearing applies to *pre*-tax WACC.

Overall, the rule probably provides a new incentive to adopt Ofgem's optimal gearing. However, distributors would need an explicit allowance for the transaction costs of achieving Ofgem's "optimal gearing" (i.e. the costs of issuing new debt or equity). Without that, Ofgem would be basing the revenue allowance on a scenario that cannot be achieved at a cost that lies within the revenue allowance.

- **Basis for revenue allowance for tax:** Ofgem can include tax as a company-specific line item in costs, or as a company-specific adjustment in the calculation of post-tax WACC. Ofgem prefers the former, because it allows the use of a common post-tax WACC for all companies, rather than a company-specific post-tax WACC. Ofgem says that this method is potentially more transparent and less complex. In practice, both methods require information about company-specific tax payments or rates and, if Ofgem mimics Ofwat's calculation of the post-tax WACC, neither method requires a <u>common</u> industry tax rate. Hence, the difference lies in presentation, rather than methodology.

It is in customers' interests to give companies an incentive to seek out tax benefits where these do not put future financial security at risk. Ofgem proposes to set a fixed allowance for tax, but as yet has said little about how this allowance would be estimated (and hence whether it would offer any long-term incentives for tax minimisation). Ofgem should provide further details without delay.

Gearing and credit weighting: Ofgem intends to assume a level of gearing "consistent with companies maintaining a credit weighting that is comfortably within the investment grade category". Ofgem also asks for submissions on whether the assumed debt:RAV gearing should be raised above 50%, given that average gearing is currently close to 70% and yet all distributors (with one exception) have credit ratings of BBB+ or better.

As NERA explained in its presentation to Ofgem (footnote, previous page), an efficient and prudent capital structure should be consistent with a single-A credit rating. This is because recent experience has shown that long-term debt markets can be closed, or at least prohibitively expensive, for energy firms graded at BBB+. Ofgem should not therefore assume a scenario in which a small change can push distributors into a position where they might not have access to low cost debt. A credit rating of A allows firms a buffer of one grade (i.e. it allows distributors to drop to an A– rating) before they reach this level.

Ofgem assesses that a debt:RAV gearing of 60–65% is consistent with an A– rating. This assessment is consistent with studies that NERA has undertaken in the water industry. Given this assessment, NERA would advocate a gearing in the range of 55–60%, which is likely to be consistent with a "central A" rating as discussed above.

Financial indicators: Ofgem will undertake financial modelling to check the financial position of distributors under the proposed price controls to ensure that they are able to maintain access to finance on reasonable terms. Ofgem intends to use central case forecasts for its financial modelling**:**

“The projections will be used to calculate certain key financial indicators. These will be assessed, and companies’ revenue requirements will be adjusted where necessary, to ensure that each company is able to maintain an appropriate level and trend of these indicators if outturn results are in line with the forecasts assumed”.

Rather than carry out central case modelling, NERA believes that modelling should reflect downside risks against minimum financial ratios. An essential consistency check for all price control decisions is to ensure that the cost of debt assumed in the calculation of the WACC is consistent with the projected financial ratios for a <u>range</u> of economic scenarios.

If Ofgem does decide to proceed with central case projections as the basis for setting prices, rather than a wide range of scenarios, then the thresholds should not be those applying in a situation of relative certainty. Ofgem should adopt threshold levels for financial ratios that are some way above minimum levels needed for the chosen credit rating, to allow for the likelihood that the outturn will be worse than the central case, and also for the consequences (for example, default or bankruptcy) in such an eventuality.

Conclusion on the cost of capital: Ofgem has set out some good intentions, but does not put them into practice when describing proposed methods. Ofgem’s proposals still amount to a highly subjective and selective approach to calculating the WACC, which is likely to allow inconsistencies in the use of discretion. We strongly recommend a more formulaic approach to the WACC calculation, if only as a check on consistency. We can see the value of using alternative methods for calibrating this formula, but we do not believe that Ofgem should use differing results to justify a subjective interpretation of all available data. Such an approach would not be conducive to transparency and, in this crucial area, financial markets will be sensitive to any biases or risks to long-term returns.

[pension issues

follows]

Treatment of pension costs

Allocation between price-controlled and other activities: Ofgem's paper proposes to make allowance for only the network monopoly part of the overall business. This applies to present employees as well as those who left in the past and would now be classed under non-distribution services.

The cost of pension obligations caused by past employees in formerly bundled activities (for example, distribution and supply) derives from statutory obligations that companies cannot reduce or avoid, and which are not imposed on other companies. These obligations could not have been costlessly transferred to any competitive business unbundled from distribution, since such a business would not be able to recover such costs in a competitive market.

These pension costs can therefore be likened to a sunk or stranded cost. As with other such costs, we believe that Ofgem needs to make allowance for their recovery by the most efficient means. Efficiency would normally dictate that companies recover sunk or stranded costs through charges for services whose demand is less price sensitive – which means through network charges rather than supply prices.

In practice, supply businesses will be unable to raise their charges (or margins) to cover additional, sunk pension costs. Ofgem may believe that it is under no obligation to provide a means of cost recovery for these cost items, and that it is legitimate for shareholders to bear the costs. However, a regulatory decision based explicitly on the presumption that costs will not be recovered may be contrary to Ofgem's duties under the Electricity Act and it may place trustees of pension funds in a position that is contrary to their duties.

Past over or under provision: Since Ofgem did not provide any explicit guidance in relation to pension provision in previous reviews, it now proposes to make an assumption about the level of employer contributions that were allowed. Ofgem has suggested three options for this assumption:

- "An allowance equal to the same percentage of total actual salary costs incurred in the period as the accounting charge for pension costs in the base year for the relevant price control review bore to actual salary costs in that year,
- An amount equal to the contributions actually made, or
- An amount equal to the average level of contributions actually made by all companies".

Ofgem would then compare this retrospectively defined allowance with actual contributions, and carry forward any net difference as an adjustment to future contributions (in order to prevent double counting of past shortfalls against the allowance, or to reimburse past contributions above the allowance).

The retrospective re-definition of regulation implied by the first and third of these rules is non-transparent, subjective, and harmful to incentives. Moreover, the first rule would produce biased figures if contributions in the base year were not typical or sustainable, for example because of a short-term pensions holiday. The only objective assumption Ofgem can make now is the second option – an allowance for the contributions actually made – since this is most likely to reflect the contribution that companies would have assumed they would be allowed.

Ofgem says that it wishes to adopt this treatment in subsequent reviews, in which case we would want Ofgem to record the allowance explicitly, to avoid the need for similar retrospective guesswork in the future. However, Ofgem does not normally adjust future allowances for opex in the light of differences between past allowances and actual costs, in order to preserve incentives to cost reduction. Pension costs are no different from any other kind of opex, in that reductions now can lead to higher costs later. Hence, Ofgem should explain why this special treatment is desirable in the particular case of pension contributions.

Early retirement deficiency costs: Ofgem maintains that "the treatment of these costs was not separately defined in the past". However, we have previously pointed out that Ofgem explicitly chose <u>not</u> to include them in 1995, a fact that Ofgem seems to have failed to take on board.

Ofgem proposes to "exclude the impact of early retirement deficiency costs resulting from redundancy and re-organisation which have been offset by the use of surpluses, rather than being funded by increased contributions". In practice, there is little difference to shareholders whether redundancy costs are paid out of pension surpluses or out of increased contributions, since shareholders have ultimate ownership of any pension surpluses or deficits, just as they are required to meet contributions into the pension fund.

Therefore Ofgem's distinction between the source of redundancy payments appears spurious**:** either redundancy costs are allowed for or they are not.

Ofgem acknowledges that these costs have not been recovered and that consumers have benefited from them, but claims to be unware "of any commitment or basis for expectation that these costs could subsequently be recovered from consumers as part of the next price control review. Ofgem would be prepared to consider any evidence that the affected companies or other interested parties can provide to clarify this issue".

Excluding efficient costs on the basis that Ofgem did not explicitly announce that those costs would be recoverable is simply regulatory opportunism. Ofgem has offered few, if any, commitments to the recovery of costs in general and demanding evidence of such a commitment for pension costs is unreasonable. Ofgem needs to provide for the recovery of these costs – like any costs – if it wishes to retain any incentive for companies to undertake similar efficiency restructuring in the future.

Stewardship: Ofgem should not introduce a further test that it cannot hope to measure objectively. At the least, it should set out a detailed interpretation of what, in its opinion, constitutes acceptable stewardship practice.

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