Response by EDF Energy to Ofgem's Initial Consultation Document on the Fifth Electricity Distribution Price Control Review for 2010 to 2015

EXECUTIVE SUMMARY

DPCR5: EDF Energy's response to Ofgem's Initial Consultation Document

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EDF Energy believes that the electricity distribution networks industry will face significant change during the next price control period and we are pleased that this is reflected in Ofgem's comprehensive initial consultation document. However, we do not believe that it will be practicable for the RPI@20 project and DPCR5 not to strongly interact.

It is our intention, during the development of our vision for both capital investment and operating expenses, that we will put safety at the heart of our plans. As part of our desire as an organisation to move to an environment of zero harm, we have launched a fundamental review of the way that we carry out our work and the way that we interact with the network.

We have introduced five clear and simple principles of safety for our staff which are designed to provide an effective way of working while mitigating the risks inherent in electrical operations. Our review of our working practices, including a reassessment of how we work on the live network, could impact on the way that we are able to deliver our work.

1. ENVIRONMENTAL ISSUES

EDF Energy supports any rational intervention that can help to address major environmental issues within our industry provided that it is based on the long-run economically efficient solution and allows DNOs to recover all associated costs. However, we believe that DNOs will face a number of challenges and will require support throughout the DPCR5 period in addressing the wider environmental issues identified. The most obvious challenges at this stage are the ability of DNOs to adjust to the impact of DG on their networks, and an increased focus on asset investment as a greater proportion of networks approach the end of life.

Ofgem should be aware that, if DNOs are to address such challenges effectively, they will need both time and funding in order to rebuild the outward facing resources that were lost though a combination of the business separation process and the historic focus on cost reduction. To be able to respond to change if and when it happens will require the development of new skills and experience in new technologies.

Distributed Generation: Impact and Incentives

The UK has made a binding commitment to achieve its share of the EU's 20% renewable energy target, but there is substantial uncertainty over how this will be achieved (as well as over other areas of energy policy). The key areas of uncertainty relate to:

- The level of renewable electricity generation needed to meet our share of the target. Given the difficulty in delivering non-electric energy usage (for example, transport) based on renewable energy, this implies that over 30% and perhaps as much as 40% of UK electricity generation will have to come from renewable sources by 2020.
- The extent to which such generation will be connected to the distribution network. While it is clear there will be an increase in distribution-connected generation, we believe that this should only occur where it is the most economically efficient outcome. For the DPCR5 period, this means that there will still be a significant role for centralised generation, and we believe that the impact of distributed generation (especially CHP) will be less significant than is generally assumed.

We agree with Ofgem that there appears to be no evidence that DG has not been able to connect. Given this lack of evidence, we question the need for new formal obligations on DNOs. We believe it is inappropriate to discuss such obligations without compelling evidence that they are required.

EDF Energy supports the very sound principle that the prices that DG pays (or is paid) for connecting to and using the distribution network should reflect the costs (or benefits) imposed by such connection and use. In achieving this objective, we note that:

- Nodal use of system pricing (provided that it takes account of assessments in accordance with ER P2/6 and ETR130) provides an approach to reflect the value that DG can provide in deferring network reinforcement. However, the need for system reinforcement is only avoided if the DG reduces the highest instantaneous annual flow of power across components in the network.
- Part of the DPCR4 mechanism has the effect of restricting how low generation use of system charging can go, thereby potentially blunting the effectiveness of the incentive. At DPCR4, Ofgem created two price controls, one for demand charges (DUoS) and another for generation (GDUoS), with the flow of funds between these two pots restricted to very limited circumstances.
- Ofgem has proposed standardisation of the agreements for connections. As many DG/DE connections (for example, for CHP or micro-generation) are also demand connections, Ofgem's standardisation proposal implies that all connections would be covered by it. We do not believe that this would be justified.

In considering incentives on the DNOs to increase the penetration of DG in their networks, we have found the DPCR4 DG incentive to be generally ineffective. This is mainly because it applies only to costs recovered through GDUoS, whereas most of our DG connections require only sole-use assets whose costs are recovered through the connection charge.

DNO Role in Managing Customer Impact

A number of issues raised in Ofgem's consultation document imply a broader DNO responsibility for customer contact. For example:

- Organising transmission access arrangements on behalf of DG
- Contracting with DG or demand in lieu of network reinforcement
- A more active role in community energy schemes
- A more pro-active role on energy efficiency
- Encouraging a more efficient use of the distribution network, for example with regard to power factor

EDF Energy has a number of observations in this area. In particular:

- We believe that the role of engaging with users on energy efficiency should continue to primarily rest with energy suppliers. They have a more developed relationship with end-users, and can potentially enhance competitive advantage through the quality of their energy efficiency advice.
- Management of power factor can avoid network investment through improved power flows. In some circumstances, this justifies investment in power factor correction equipment, but customers will often not make this investment. We believe that it would be more efficient to place an incentive on DNOs to trade-off investment in power factor correction with other network investment.
- We believe that it is possible to go further and consider more market based arrangements to incentivise connection of DG and demand-side management schemes, where these offer a lower cost solution than network reinforcement.

DNO Role in Managing Losses

We believe it is appropriate that DNOs are incentivised to manage both technical and non-technical losses. However, we also agree with Ofgem's observations about problems with the current losses incentive mechanism. We believe that a different approach to incentivising reduced losses is required, since we have no reason to believe that the current mechanism will properly reveal the underlying technical losses.

To provide incentives on technical losses, we see merit in exploring the use of a technical model or reference network. Indeed, such a model could be integrated with the load-flow models that some DNOs have developed for nodal EHV DUoS pricing (though a losses model would need to incorporate the lower voltages in some way). We also agree that it would be possible to reward specific loss-reducing initiatives.

We would not agree that reducing non-technical losses is a role only for electricity suppliers. During the DPCR4 period, we have put substantial efforts into reducing commercial losses – these reductions would not have happened had the task been left to suppliers alone. We believe it is important to maintain incentives on non-technical losses. Such a mechanism could be achieved by retaining an incentive on "found" units accepted by the relevant supplier.

Environmental Incentivisation

The consultation paper highlights the main ways that a DNO's activities have an environmental impact, but does not mention waste management. We generate many thousands of tonnes of materials excavated from the ground which currently must be sent to landfill. This practice is unsustainable and we have thus been developing techniques to improve the recycling and reuse of this material.

It is clear that there are a number of areas which should be subject to incentives (quantitative wherever practicable, qualitative where not). These would include: CO_2 from use of transport, CO_2 from buildings, waste management, employee engagement, and the reduction of sulphur hexafluoride.

Other Issues

- We do not agree that the kWh driver incentivises DNOs to deliver more (rather than less) energy. We and other DNOs have taken a number of actions to reduce the amount of energy delivered.
- Ofgem has previously made statements on the possibility of using DNOs to fund the stranded costs of meters that could result from an accelerated roll-out of smart meters. We note that Ofgem did not comment on this issue in the consultation paper. We believe that this is an omission which should be rectified as we move through the DPCR5 process.
- The scheme for Areas of Outstanding Natural Beauty has been very popular with our stakeholders and we wish to see it continue, and even extended, so long as there is customer support for it.

2. CUSTOMERS

Quality of Supply

In general, we believe that the quality of supply incentives are working well, but that there is room for improvement – especially in improving the reliability of supplies to the worst-served customers.

We agree with Ofgem that there should not be too wide a gap between average service levels and those for the worst-served. We would therefore support an appropriately funded incentive aimed at reducing this gap.

We note that Ofgem has suggested three incentive mechanisms for improving quality of supply for worst-served customers. We believe that the third of these options offers the best way forward.

Connection Issues

Ofgem notes that some customers express concern about the quality of service received from the DNOs in the provision of connections to the network. We share Ofgem's concern, and support reforms to improve this area – provided that the revenue allocation to each DNO takes due account of the actual costs of providing a connections service. These costs will vary with the number of enquiries received and the volume of projects implemented – both of which are substantially independent of the Composite Scale Variable (CSV). To introduce an incentive without accounting for these costs would be discriminatory between DNOs.

There are a number of approaches that can be taken to reduce the lead time for a new connection:

- It may be possible to develop a scheme whereby the DNO can build infrastructure ahead of need, provided that the risk of doing so is not entirely passed on to customers. In such cases, the DNO could be rewarded for making the right choices, and penalised for building assets that become stranded.
- New technology may reduce the need for major network reinforcement to accommodate new connections. In recognition of this, we propose the expansion of the RPZ scheme to include a limited amount of deployment of new technologies.

Ofgem suggests a number of additional regulatory interventions in the area of connections. In the main, these look at increasing competition in the provision of connections, but regulating the connection charges to domestic customers is also considered.

- Before embarking on further measures to support the development of competition in connections, Ofgem should assess whether the competition that has emerged so far is *effective* competition, and in particular examine whether the incentives on IDNOs could increase costs to consumers in general (for example, in order to pay for discounts given to developers).
- We do not believe that the DNO connections business should be separated. To do so would take DNOs further into competition that does not deliver benefits to the customer. Such a separation could deprive the DNOs of operational synergies, which would raise costs for consumers and could reduce operational capability during network emergencies.
- Ofgem appears to reject any suggestion that DNOs should charge a margin on connection activities, on the grounds that competition is not yet effective. However, it is difficult to see how competition will ever be effective if new entrant ICPs are forced to compete against an incumbent required to charge at cost. We ask Ofgem to reconsider its position.

- Regulating the level of connection charges for domestic customers (or other customers not protected by competition) is unnecessary and has not been shown to be justified.

An important omission is the lack of any signal that connection charging policy will be reviewed as part of the DPCR5 process. Our forecasts for the DPCR5 period indicate that an increased proportion of costs will not be recoverable by connection charges compared to the DPCR4 period, and this is in part due to the shallowing of connection charge policy introduced for DPCR4.

This is a problem because it increases the cost burden that falls on the generality of customers compared to that falling on those causing the expenditure. It used to be the case that a DNO would only make an allowance for general reinforcement if any surplus capacity (usually due to the standard sizes of plant) would be of foreseeable use – in other words, if there was a need for general (non-attributable) reinforcement anyway. However, the introduction of cost apportionment factors into DNO connection charging methodologies has taken away discretion, with the result that the costs of additional capacity always fall on the DNO, and hence on customers generally.

For example, under the current approach, a customer requiring 10MVA which requires us to install 20MVA of transformer capacity (being the DNO's standard configuration) would, under the cost apportionment rules, pay only 50% of the costs even where the DNO has no prospective need for the surplus capacity. We believe that the costs of additional capacity in such circumstances should be 100% funded by the customer.

We ask that Ofgem take a fresh look at connection charge policy as part of this review so that the generality of customers only incur non-attributable LRE costs.

Of course, increasing the proportion of connections fully funded by connectees will also have the benefit of increasing the amount of connection work which is contestable and hence should encourage the development of competition.

Communications with Customers

We agree that DNOs should be responsive to the views and needs of end-users. Indeed, in addition to the views expressed by customers via Ofgem's customer survey, we have identified a number of issues which we believe are of particular concern to our stakeholders. Our DPCR5 consultation will be open from 1 July to 28 September and details can be found at ww.edfenergy.com/dpcr5

As we, and other DNOs, take forward our own stakeholder consultation, it will be important to consider the legal basis relevant to the weight that a DNO should give to the various stakeholder responses received. Our initial view is that DNOs should assess responses in relation to their section 9 duties under the Electricity Act 1989.

Ofgem has suggested a need to set complaint-handling standards for DNOs. We note that DNOs are already under a licence obligation to prepare and publish complaint-handling procedures, and to have these in place as part of the (currently voluntary) ombudsman arrangements. DNOs should therefore be given the chance to demonstrate that they have effective complaint-handling procedures in place.

3. NETWORKS

We believe that, if the costs associated with the core operation of the distribution network are to be determined objectively, there must be explicit links between Ofgem's Long Term Electricity Networks Scenarios (LENS) project and DPCR5, since it is not appropriate to set allowances through to 2015 without agreeing on the overall strategic direction that DNOs are expected to take.

Benchmarking of DNO Costs

For this current review, Ofgem has indicated a number of potential changes to its approach in this area, including:

- A review of the approach to benchmarking DNO costs.
- A new building-block approach to modelling the component costs of a DNO.

We support both these initiatives, but caution that all forms of benchmarking and modelling are imperfect – and hence care is needed to ensure that these imperfections do not cause undue discrimination against some DNOs. Avoiding discrimination depends, in part, on the quality and consistency of data available to Ofgem on each DNO's costs. While the RRP has greatly improved the quality of reporting, there are still many anomalies which will need to be resolved. Ofgem should not hesitate to use its compliance powers where a DNO has failed to comply with the RRP rules.

Improving the data quality will not be sufficient to remove discrimination from the benchmarking process. We believe that the CSV approach as used at DPCR4 was so discriminatory that revised benchmarking is required that takes more account of the actual DNO cost drivers.

Ofgem's new building-block approach to cost assessment seems appropriate but it remains unclear how the various elements will be combined to produce a robust result. To maximise the chance of this:

- We would encourage Ofgem to be clear about how the various process elements fit together and to set these out in a detailed timetable. It is a concern that we are currently unaware of the scope and timing of any bottom-up benchmarking.
- Ofgem should take account of the degree of error inherent in each component when building a virtual DNO from building blocks. To do otherwise is likely to result in at least some of the resulting virtual DNOs being unsustainable.

Measuring Outputs

- We believe there is a need to develop sensible measures of indirect outputs (for example, to detect where the risk of network failure is changing). In deriving such measures, we would support the development of a joint definition of asset condition categories.
- We see little scope to develop new measures of direct distribution network outputs.

Managing Uncertainty

At DPCR4, Ofgem introduced the sliding scale incentive (IQI) as a means of resolving differences of view on future capex needs. The IQI has proved to be a useful tool, but Ofgem should revisit its calibration. In resetting the IQI, care will be needed to make sure that DNOs are not penalised for carrying out necessary investment. We note that under the recent gas DPCR, a company that proposes a level of capex greater than Ofgem's forecast, but which nevertheless spends at its forecast level (with such expenditure being deemed to be efficient and entering the RAV), will still receive a penalty.

For the DPCR5 period, there is increasing uncertainty over some areas of DNO capex – not least capex relating to upstream investment to support DG. The use of revenue drivers could be appropriate for areas such as this.

Furthermore, our forecasts show that an increasing proportion of our Load Related capex expenditure will be RAV, rather than connection charge, funded. RAV funding increases risks on the DNO because it is hard to forecast while being subject to an incentive rate (connection charge funded work always has a net zero cost and a zero incentive rate), and also because it is more at risk from unit cost increases (connection charges can more easily follow prices). Ofgem will need to bear these risks in mind when calibrating and applying its Information Quality Incentive and when devising any adjustment mechanisms for relative price effects.

Balancing Incentives

The price control regime has so far allowed companies to earn a return on capex, but not on opex. At DPCR4, we argued that this was causing a major distortion to Ofgem's benchmarking of controllable costs. We believe that our view has been entirely vindicated by the improvements in reporting that have been driven by the introduction of the Regulatory Reporting Pack. We would support an approach that equalises incentives across the main expenditure categories.

4. FINANCIAL ISSUES

Recent utility company takeovers have renewed public focus on the appropriate cost of capital for regulated utilities. A number of these deals have been at substantial premium to the value of regulated assets (the RAV). We believe that recent high premiums to RAV can be explained by the following factors:

- The use of highly leveraged structures (in holding companies) to maximise the tax-shield benefits.
- The use of high levels of index-linked debt to create equity return benefits.
- Over-optimistic assumptions about the regulatory out-performance likely to be achievable.
- A continuing belief among investors in an underlying regulator/government guarantee against financial distress.

Future Cost of Debt

The future cost of debt is subject to much uncertainty in the current credit crunch environment, and likely to be subject to volatility for at least the near-term future. While it is theoretically possible to construct effective debt-indexation or trigger mechanisms, the practical problems are formidable. The principal protection against volatility is to encourage sensible levels of gearing by appropriately remunerating equity.

In determining an appropriate estimate of the future cost of debt, it is perhaps too early to evaluate the impact of the credit crunch. Clearly, this will need to be kept under close and continuing review between now and the formulation of Ofgem's final proposals.

Use of index-linked debt creates a major problem that the regulatory framework needs to address. With such debt, cash interest is payable based on the coupon and index value of the debt, with coupons being typically 2-3% lower than those for comparable straight debt instruments. There is clearly a cash-flow benefit to this (particularly in early years), but at redemption it is the indexed value that is paid, and not the original principal.

This means that a licensee with index-linked debt should retain the cash savings on the interest payments in order to provide for the higher redemption cost. However, there is nothing in the current price control framework to ensure this, with the result that there is nothing to stop this money from being handed to shareholders as increased dividends.

Underlying Business Risk

We agree with Ofgem's view that the appropriate cost of capital for a DNO depends on the overall balance of risks and rewards contained in the price control package. The corollary of this is that the allowed cost of capital for the DNOs must be primarily driven by how the regulatory package deals with the underlying business risks that the companies face.

At this time, we believe that those risks are increasing for DNOs, not least because of the increased investment required in network assets. Investment risks are largely systemic: for example, the risk of cost overruns is systemic throughout the economy, as is the risk of increased input prices. Such systemic risks cannot be diversified by shareholders and so will increase the cost of capital.

In addition to an increase in the underlying risk of the DNO business, it is possible that DNOs will be required to manage more explicit risks (for example, by being asked to build assets ahead of need and to take the risk that such assets may be partially stranded). We are willing to consider accepting increased levels of risk provided that appropriate rewards are built into incentive arrangements, with the prospect of increasing returns on the RAV by up to 2% real.

Gearing Levels

Ofgem may want to raise the assumed gearing level for DNOs above the current 57.5%. We do not believe that it would be appropriate to make significant changes to this gearing level.

Other Financing Issues

- Financeability payments: these are not required provided that the cost of capital is set at a level that attracts equity formation. But in practice, the markets are not used to UK regulators assuming high levels of retained earnings or even rights issues, and this suggests that a more cautious approach will be needed.
- Changes to tax regime: we are broadly in favour of a symmetrical mechanism for ex-post adjustments for major changes in the tax regime, as these are likely to be mostly beyond our control. There needs to be a clear distinction between the treatment of such tax changes and real tax efficiencies.
- Return on non-operational capex: we believe it is important that Ofgem should continue to incentivise DNOs to strive for future efficiencies in their business. As recognised by Ofgem, we have reached the point of diminishing returns for these future efficiency programmes. We therefore feel that it is appropriate for Ofgem to consider allowing non-operational capex to be allowed as part of the RAV.

EDF Energy, June 2008

DETAILED RESPONSE

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DETAILED RESPONSE

Environmental issues

Question 1: Do you think that evolutionary or revolutionary changes are required to the role of the DNOs to ensure that distribution networks remain fit for purpose? If the latter, in what specific areas does this apply?

Whilst we support the Government's commitment towards producing 15% of the nation's total energy needs from renewables by 2020, there remains considerable uncertainty as to how this will be achieved; though it is now acknowledged that over 30%, and even up to 40%, of electricity would need to be generated from renewables by 2020 in order for this target to be realised.

This being the case, we believe that the key issue for DNOs is how they can respond and be in a position to facilitate the necessary changes. DNOs (and EDF Energy in particular) have already begun to make a valuable contribution through their proactive embracement of new technology and, in particular, through financial and technical support of RD&D projects focused on active network management.

However, not surprisingly, two decades of incentives primarily focused on cost reduction have left DNOs with little headroom in terms of a pool of professionally qualified electrical engineers able to respond to the anticipated changes. Going forward, there will need to be an increased emphasis on acquiring the necessary skills to effect the necessary development and deployment of new technologies. This will require new investment in terms of recruitment, training and skills development, and it is essential that new incentives are introduced for DPCR5 to make this possible.

Distributed generation

The main area of uncertainty concerns the level of distributed generation (DG) that will connect to the distribution network, and the impact this will have on the way distribution networks are designed and managed.

The Crown Estates Rounds 1, 2 and 3 leasing programme indicates that up to 33GW of offshore wind could be developed by 2020. Of this 33GW, it is likely that some 25GW will need to have been developed and be in full operation by 2020 for the overall 15% target (and the 40% from electricity target) to be achieved. Such generation would predominantly impact on the GB transmission system. However, a proportion might connect to DNOs' networks; for example, up to 50% of the Round 2 offshore wind sites might still connect to 132kV distribution networks.

Onshore wind might also make a significant contribution, and this would be likely to impact typically on DNO's 33kV and 11kV networks. The South East and East Anglia have many locations which are suitable, in terms of availability of wind resource and potential planning consent, for onshore wind installations.

With high levels of intermittent generation connected to transmission and distribution networks, storage and demand side management (DSM) might in future need to play an increasingly important system balancing role. DNOs will need to develop the capability to facilitate these processes.

In terms of other renewable electricity generation opportunities, if the economics improve, new medium-sized biomass fuelled power stations could make an increasing contribution. Such power stations would be likely to connect typically to DNOs' 33kV and 11kV networks and, again, the highly cultivated areas of South East England and East Anglia would seem to be well placed to take advantage of biomass opportunities.

In terms of the potential for other decentralised electricity generating technologies to make a significant contribution, our analysis shows that gas-fired CHP can deliver only very limited carbon savings and, even then, this benefit will begin to erode due to the significant decarbonisation of large centralised generation that will occur rapidly in coming years. Furthermore, many of the on-site renewable technologies, such as solar photovoltaic, micro-wind and biomass CHP, are relatively expensive and/or are likely to experience supply chain constraints.

However, local generation does have a role to play, and planning requirements already oblige developers to consider on-site generation. These requirements are expected to gradually increase over the DPCR5 period. In fact, by 2016, the Government has proposed that all new homes should be zero carbon. While the definition of 'zero carbon' is currently unclear, it is likely that all new developments will need to meet a proportion of energy demand through on-site generation.

Due to the housing shortage in the South and the East of England, these regions will probably see some of the highest levels of zero carbon home new-build activity, and this will impact on 11kV and especially (new) LV network design.

Transport and electric heating

With the rapid de-carbonisation of the centralised electricity generation fleet, significant opportunities exist for 'fuel switching'; that is, using low and zero carbon electricity for transport and heating.

The likely uptake of these technologies is currently very uncertain, as are the potential timescales. However, we believe that as early as DPCR5, these technologies will begin to have an impact on electricity demand and will possibly create some opportunities for electricity storage, for example hot water storage, or the storage of electricity in car batteries. From a system balancing perspective the plug-in hybrid car, which is likely to become increasingly common during the DPCR5 period and beyond, could either be very problematical (if their owners recharge the vehicle as soon as they return home from work, i.e. at times of system peak demand) or a valuable storage facility if they feed into the grid when demand is high and recharge when wind farm output exceeds system demand (which, with over 25GW of wind, it could well do at night).

Network operators will need to ensure that the networks are able to facilitate the growth in these technologies and take advantage of any benefits they offer.

Conclusions

Depending on how things develop, distribution networks could experience significantly different, and potentially far less predictable, power flows and demand profiles in future; so much so that local active network management and local system balancing are likely to become important aspects of distribution network management. These are not small changes to the DNO role and it will be necessary for DNOs to quickly evolve such that they are capable of operating their networks more actively and managing their businesses in a more complex trading market. However, although some of the active network management technologies now under development could be described as revolutionary, the required changes to network architecture will necessarily be evolutionary due to the substantial legacy network that exists today. What should be revolutionary is how DNOs and Ofgem work together within the regulatory framework to ensure that Great Britain is able to recruit, develop and retain the skills necessary to design and manage these future more complex networks and markets.

Question 2: Do you think that we have identified the key areas where DNOs can facilitate activities that have a positive impact on the environment?

In general, the document highlights the main areas in which a DNO's activities impact on the environment. However, one area that is missing is waste management. For example, in developing and maintaining our networks we generate many thousands of tonnes of materials excavated from the ground. Current legislation requires that this excavated material be sent to landfill. We believe that this practice is unsustainable and have been developing techniques to improve the recycling and reuse of this material. In our opinion, it would be appropriate for a DNO's approach to waste management to be included within any assessment of its impact on the environment.

EDF Energy has put the environment at the heart of its business operations. Launched on World Environment Day, 5 June, our plan entitled "Our Climate Commitments" (OCC) sets targets and outlines how the company will reduce its own environmental impact and help customers reduce their energy consumption in the UK. In developing ways of maintaining profitability whilst encouraging its customers to use less energy, EDF Energy is making a fundamental change in its whole approach to energy and energy services.

At the centre of OCC is a plan to cut the intensity of CO_2 emissions from our electricity production by 60%. Nationally, and based on our current generation fleet, this represents a reduction of around 12 million tonnes of CO_2 annually by 2020.

In addition to this, EDF Energy's aims include:

- Reducing the proportion of CO_2 arising from its customers' energy consumption by 15% by 2020
- Reducing the volume of materials sent to landfill by 50% by 2012
- Taking action to cut CO_2 emissions from its offices and depots by 30%, and from its transport by 20%, by 2012
- Increasing the recycling rate for its office and depot waste beyond the national average (a minimum of 65% by 2012)
- Reducing the volume of waste the company produces in its energy billing activities by 30% by 2020

Another element of the plan is inspiring all of its employees to champion its energy pledges by taking active steps at home and at work to reduce their carbon footprint and that of others by 2012.

This industry-leading initiative was followed up in 2008 with the publication of 'Our Social Commitments' (OSC) on 14 February.

Whereas OCC focused mainly on climate change, OSC covers a wide and diverse range of challenges – energy affordability, security of supply, safety, ethical procurement, employee development and community investment. Like OCC, these pledges are bold and ambitious and, taken together, like OCC, they go beyond anything yet seen in our sector.

Each of the branches within EDF Energy has collective responsibility to meet the commitments outlined above, however some are more specific. For Networks, the areas in which we are either a sole owner or a significant contributor are as follows:

Electricity distribution - climate commitments

- CO_2 from transport

- CO_2 from buildings
- Waste from our streetworks activities
- Waste from our offices and depots
- Waste to landfill
- Employee engagement

Electricity distribution - social commitments

- Delivering a safety message to our communities
- Supporting the vulnerable during power outages
- Ethical procurement

These come on top of existing arrangements to monitor electrical losses (i.e. the current regulatory mechanisms) and reporting on sulphur hexafluoride (SF_6) and fluid-filled cables.

Question 3: How do we ensure progress is made on the issues identified with the connection of DG? Should progress be facilitated through a working group or should more formal obligations be developed?

A number of cross-industry working groups are already addressing some of the perceived 'issues' with the connection of DG. Some examples are the Distributed Energy Working Group, which is addressing market and licensing issues for small-scale DG; a working group progressing helpful revisions to ER G59 and G75 for medium-scale DG; and the ENSG and its working groups, which are addressing potential technical barriers and the more strategic issues regarding the 2020 targets.

Ofgem makes a number of proposals with regard to perceived barriers to the connection of DG without citing any substantive evidence that these matters are impeding its development. Indeed, Ofgem notes that "there appears to be no evidence that DG has not been able to connect". While we would support a working group to examine the suggestions proposed, a discussion of formal obligations is inappropriate without any evidence of need.

We have found the DPCR4 DG incentive to be generally ineffective for a number of reasons:

- Firstly, it was unnecessary to incentivise DNOs to offer the minimum cost connection (which is what the incentive is designed to do), since they are already under a licence obligation to do so.
- Secondly, the incentive applies only to costs recovered through GDUoS, not through connection charges. It has been our experience that the cost of connecting DG has largely been incurred in providing sole-use assets, which are recovered wholly through connection charges. These means that, taken together with the fact that most DG connections so far have required little upstream reinforcement, there are no costs subject to incentivisation.

We do not believe that the limited take-up of the RPZ incentive scheme is the result of its design; on the contrary, it is largely due to the limited number of DG applications for connection, together with the fact that most DG connection scenarios do not lend themselves to technically innovative solutions which are cheaper than conventional upstream reinforcement. However, if there is to be a much higher penetration of DG in the future, it remains important to continue to incentivise innovation, and we would wish to see the scheme retained and/or possibly extended.

Extending the scope of RPZs to include demand side participation is sensible, but we would also support the development of funding and incentives for innovatively managing networks on an ongoing basis. We would therefore urge Ofgem to consider changes to the way the incentive works. Linking the incentive directly to DG capacity connected (or, say, DSM capacity contracted) can be a barrier to innovation since a DNO will be rewarded only when (or if) the capacity materialises. We would also urge some relaxation of the current requirement that an RPZ can be registered only where the technology has not previously been applied in Great Britain. Many promising active network management technologies have been developed as IFI (part) funded projects, and permitting field trials of these technologies, to enable them to be registered as RPZs, would provide the best assurance that these prototype technologies would be productised, commercialised and developed as marketable products and not simply 'left on the shelf'.

The development of DG continues to be very uncertain, particularly in terms of scale and location. What is important, therefore, for DPCR5 is the continued development of new commercially available products and the development of DNO capability (in terms of skills and technology) to ensure that we are ready if and when the demand materialises.

This suggests a range of funding and incentive arrangements, which perhaps take the following form:

- The IFI scheme to encourage research and development
- A scheme to encourage experimental deployment of technology, with two parts:
    - Where the technology is of specific benefit to a connectee – cost recovery from that connectee (via the connection charge or use of system charge), as per the current RPZ mechanism

— An element to encourage the experimental deployment of new (including 'smart grid') technologies – the cost of which would be recoverable from the generality of connectees – demand and generation

— Innovation here should include innovation of both technologies and commercial/contractual arrangements

- Given that funding is required to develop DNO capability, and DG will be deployed more in some DNOs' areas than others, the benefits of funding are maximised if the funded projects are 'demonstration projects', i.e. the intellectual capital is shared
- A scheme to fund the development of distribution sector skills, including an element relevant to new technologies

Question 4: Do you agree that DNOs should have stronger financial incentives to reduce their carbon footprint? Do you think that we have identified the key areas where it may be possible to do this?

We agree that DNOs should have stronger incentives to measure and reduce their environmental footprint, including their respective carbon footprints.

We believe that there are a number of areas which should be subject to an incentive (quantitative where traceable, qualitative where not):

- CO_2 from transport
- CO_2 from buildings
- Waste management
- Employee engagement
- Sulphur hexafluoride (SF_6)

Of course, there are other areas of environmental impact which should not be forgotten, and these should be embraced within any new/revised incentive arrangements for DPCR5. On the other hand, some will require more analysis before they can be embraced – for example, accounting for the energy (and carbon) cost of the production and supply chain associated with the cables and plant we use. While it would be possible, in theory, to develop a carbon accounting approach which included this aspect, because of the work and complexity involved in setting up such an approach, we suggest this is a development which should be left for subsequent reviews. In the meantime, however, we should be conscious of these carbon costs in any decision to use higher capacity plant, or prematurely retired plant and equipment, in pursuit of a low carbon agenda (for example, increasing network capacity to connect DG and/or reduce losses).

Losses

We agree with Ofgem's observations regarding problems with the current losses incentive mechanism, and that the challenge is to find a way in which cost-effective approaches to reducing losses are rewarded.

In the DPCR4 period we have put substantial efforts into reducing commercial losses. In particular, we have established a large dedicated team to detect consumption not recorded in settlements and to work with suppliers to encourage correction. We have invested just over £3m in a consumption database to assist us in this work, as well as the cost of many thousands of site visits.

The reduction of commercial losses is currently incentivised by a combination of the unit element of the revenue driver and the losses incentive. While we recognise that cutting commercial losses does not directly contribute to a reduction in carbon emissions, we believe that it has an important indirect impact by improving the allocation of wholesale electricity costs between suppliers, and ultimately, their customers.

We would not agree that the reduction of commercial losses is solely the responsibility of electricity suppliers. As Ofgem knows from its work on revenue protection, suppliers can face perverse incentives with regard to the recording of consumption in settlements. For example, a supplier has little interest in declaring unrecorded units in settlements where it is unlikely that any customer would ever pay for them. The incentive on suppliers is for these lost units to be spread over all suppliers, via the DNO's loss adjustment factor or through the GSP Group Correction mechanism. On the other hand, DNOs face very clear incentives to ensure that consumption is fully recorded in settlements.

The losses incentive has been less successful in promoting investment in the reduction of technical losses. There are a number of reasons for this:

1. The incentive to invest in equipment to reduce losses is relatively weak in comparison to the additional cost of such equipment. This is related to the short timescale over which the incentive mechanism operates compared to the useful life of most distribution assets
2. The current losses incentive is competing with strong incentives to minimise capital expenditure
3. Perhaps most importantly, the marginal impact of an investment in loss-reducing equipment is obscured by the scale and volatility of commercial losses

We believe that a different approach to incentivising reduced losses is required. Unlike Ofgem, we have no reason to believe that the underlying technical losses will become evident with the current mechanism, even in the long run, since the impact of commercial losses and settlement error will continue to dominate.

In theory, the full roll-out of smart meters, should this begin to happen during DPCR5, would reduce the error in settlements. However, in our view, the roll-out process itself will lead to further sources of errors, particularly in view of the large amount of data involved and the new IT systems that will need to be built to cope with it.

Ofgem raises a number of alternative approaches to the current method.

We see some merit in exploring the use of a technical model or reference network. Indeed, such a model could be integrated with the load flow models some DNOs have developed for nodal EHV DUoS pricing, although a losses model would need to incorporate the lower voltages in some way. Such an approach would not be without its difficulties and would probably require additional measuring equipment to be installed on the network, for example to measure utilisation, especially at the lower voltages where there is currently little systematic measurement. There would clearly be material costs to this approach and a significant timescale involved in its development.

We also agree that it would be possible to reward specific loss-reducing initiatives. Such a scheme would reward the DNOs who invested in low-loss equipment by allowing them to recover an incentive payment related to the calculated KWhs saved over the expected lifetime of the equipment. The scheme would require values such as standard lives for equipment types to be determined, and an assessment of technical factors such as asset utilisation (which will generally vary over the life of the equipment) to be developed. The latter is especially relevant to transformers. The approach is similar in principle to a reference network model but, because it is scheme based, it would be easier for Ofgem to validate the benefits. As with the current losses scheme, we would expect the capex for low-loss equipment to be included within the capital efficiency mechanism, to ensure that the most cost-effective loss reduction schemes are targeted first. However, such an approach is less satisfactory because it would not capture actions which increase losses, such as high levels of asset utilisation.

We should also be conscious of the fact that lower-loss equipment will often have a higher initial carbon cost. Given that the generation portfolio is moving inevitably towards a lower carbon footprint (including nuclear), it follows that the carbon cost of network losses will reduce significantly over time. We should therefore be conscious of the lifetime carbon cost of alternative loss reduction incentives.

For DPCR5, we believe that the most pragmatic approach would be to implement a scheme-based incentive mechanism while taking forward work which looks at establishing a more comprehensive reference model for DPCR6.

As we have noted above, EDF Energy Networks puts considerable effort into reducing commercial losses, and we believe it is important to maintain incentives on these. This could achieved by retaining an incentive on ‘found’ units accepted by the relevant supplier, authenticated by some form of auditable ‘receipt’ (from the supplier).

We agree with Ofgem that any incentive on losses is valued against an external benchmark cost of carbon. It should also be remembered that losses increase the size of network assets needed to transport them, and the additional cost this implies should also be included in the incentive rate.

Minimising the impact of day–to-day activities

The output of any investment in the network to reduce losses will not be discernible for some time. However, DNOs can have an influence on their carbon footprint in the shorter term by changing the way they carry out their day-to-day operations. As Ofgem has noted, a number of companies already measure the environmental impact of a number of these activities. One approach would be to base an incentive mechanism on a relatively small basket of measures initially, for example emissions from transport and buildings and waste to landfill. We see that the scheme development would need to be broken up into a number of stages. These are:

- Baseline performance across key metrics – the key element of work would be the agreement of relevant definitions.
- Define the incentive scheme – there are two possible approaches. If customers indicate a willingness to pay for environmental improvements, the DNOs could work with Ofgem to identify the reductions that could be delivered for that expenditure and this could be used to set a target profile for DPCR5. We would expect the target to be tonnes of CO_2 emitted. The targets would also need to take account of any changes in activity.

We would also propose that a symmetrical incentive rate (£ per tonne of CO_2) is applied around the targets. Given that there would be no track record for such a scheme, we would recommend that, initially, a relatively small amount of revenue (0.25% to 0.5%) is subject to a reward or a penalty. An alternative would be to set no target profile and to simply apply an incentive rate around the baseline level of emissions, with a similar maximum amount of revenue subject to a reward or a penalty. This approach is likely to deliver a smaller level of improvement.

- **Audit performance** – one approach would be for Ofgem to audit each company's performance. However, a simpler option may be to require each company to have its performance accredited by a suitably qualified body and for that body to submit a report to Ofgem.

Sulphur hexafluoride (SF_6)

As was noted in the Transmission Price Control Review (TPCR), it is important to incentivise reductions in emissions of this powerful greenhouse gas because it is not covered by the European Emissions Trading Scheme (EU ETS).

We agree that it would be sensible for DNOs to be subject to an explicit mechanism relating to the loss of SF_6 from their equipment. The TPCR scheme would be a sensible basis for this; however, like the transmission scheme, there are some issues which will need to be clarified in respect of reporting and auditing the data and the treatment of exceptional events.

In addition, it would be sensible to collect data for more than two years so that a robust baseline can be established before incentives are introduced. Our view is that four or five years of data are required.

In setting an SF_6 incentive we need to be conscious of the fact that there is currently no economic alternative to SF_6, which, in any case, has many significant environmental (and safety) benefits over mineral oil insulation. Mineral oil is used in much of the switchgear that DNOs will be replacing during DPCR5 and beyond. It follows that SF_6 volumes will increase, as, therefore, will volumes used for routine top-up (i.e. top-up as allowed for within the design criteria for the equipment, not due to plant defects).

Fluid-filled cables (FFCs)

In terms of asset risk management, we regard the location of FFCs (relative to source protection zones, for example) as a main part of the 'consequence' component of risk assessment and we are categorising our FFC hydraulic sections on this basis. Our current investment plans are targeting the replacement of the poorest-performing cables in the most environmentally-sensitive areas. In our stakeholder consultation we are also seeking views on whether the replacement of this technology should be at a faster rate.

We believe that there would be merit in developing a scheme to incentivise companies to reduce leakage from FFCs. We agree that, ideally, leakage should be categorised dependent on the environmental sensitivity of its location. ENA Engineering Technical Report ETR 135 provides useful guidance to such an approach. Historically, however, the data may not always have been captured at this level of granularity and this could cause difficulties in establishing an appropriate base from which to determine future targets.

Given that any oil leakage will have some form of environmental impact, an alternative would be to set an incentive scheme based on total leakage (relative to FFC population) but to put a relatively modest amount of revenue at risk. In parallel, the current reporting processes should be amended so that companies collect and report the relevant leakage data based on the environmental sensitivity of the location where the leak occurred. Since companies already collect leakage data as part of their reporting obligations to the Environment Agency, this additional burden should not be unduly onerous. This would facilitate the development of a more comprehensive scheme for DPCR6.

Question 5: How can the Long Term Development Statements be made more useful for DG and other users of the network?

We would question whether putting more information into Long Term Development Statements will have an appreciable effect beyond increasing DNOs' costs. There has been a very limited take-up of the statements from generators (what few requests we have tend to be from IDNOs), nor have we received complaints from this group that our statements are unhelpful. We are also obliged by our licence to provide data on power flows etc – an option for generators which, in our experience, is hardly ever taken up.

We also take the security implications of publishing circuit data very seriously, and would ask that Ofgem clears such publication with the relevant security services before seeking to place any additional obligations on DNOs.

One of the limitations of Long Term Development Statements as an aid to developers of DG is that, whereas planned strategic network development to accommodate new housing development and commercial growth can be described (based on well-founded RDA data), any explanation of *planned* network development to accommodate DG is severely constrained by a paucity of information from DG developers concerning their longer-term proposals. In the interim, we are developing mapping technologies which may provide better facilities for generators to undertake their own 'first pass' assessments. We believe this offers a more promising outcome than the further development of published Long Term Development Statements.

Question 6: Is the current regulatory framework constraining a DNO's ability to facilitate low/zero carbon technologies and if so, what could be done to address this?

Yes, there are a number of improvements that can be made.

Cost-reflective pricing

At DPCR4 Ofgem created two price controls – one for demand charges (DUoS) and one for generation (GDUoS) – which the flow of funds between these two 'pots' restricted to very limited circumstances (where generation assets are stranded).

The effect of this restriction is to blunt any negative GDUoS prices, because any such payments must be recovered from the GDUoS 'pot'.

Given that negative GDUoS prices arise where the presence of a generator removes or defers the need to reinforce the distribution network, and this is normally paid for by demand customers, lifting the restriction on the movement of funds between the pots would seem sensible.

Skills

Much of the focus of the last 18 years of regulation has been on reducing costs, particularly opex. While delivering significant short-term benefits to customers, this has resulted in the sector having little capacity to take on new roles and technologies.

The future of electricity production is perhaps more uncertain than it has been for many decades, particularly with regard to the role of distributed generation/energy. On the one hand, we might expect relatively modest use of distributed generation/energy on cost grounds; however, this could change because of political support/changes in technology. Demand patterns are also uncertain because of such factors as: the impact of CFLs; the anticipated continued growth in consumer electronics; potential increases in the levels of microgeneration and the expected growth in the use of electric vehicles; and improvements in energy efficiency, coupled with the potential deployment of demand management technologies.

What this means for DNOs is that they face a combination discontinuous charge (i.e. the environment in which DNOs operate changes to such an extent that the existing business model is no longer fit for purpose) and at the same time as needing to increase work in the face of ageing networks, and the growing demand for electricity in the case of EDF Energy.

The ability to respond to these challenges in a flexible manner is, therefore, a key issue for DPCR5.

In particular, a key issue for the regulatory framework is to support the rebuilding of skills to ensure that DNOs are better placed to respond to the inevitable challenge, in whatever form it takes and whenever it happens.

Research and development

The IFI scheme has been successful in reinvigorating research and development (R&D) in a sector where intensity levels had previously fallen close to zero.

However, the scheme does not include funding for the initial deployment of new technologies – with the exception of the rather narrow window provided by the RPZ scheme. Limited deployment of new technologies would help DNOs to develop skills and operational experience, and would lead to a reduction in costs if and when a more widespread roll-out became necessary.

Reactive power

A poor power factor increases electrical losses (and hence carbon emissions) because the entire electrical infrastructure (from generation through to transmission and distribution) has to supply the additional current generated by the source of the reactive power. It follows that losses will be incurred by the heating effect of this additional current on the electrical resistance of the upstream electrical infrastructure. Customers say that they want more information on how to improve their power factor. While DNOs will generally offer such advice on request, a more proactive approach towards offering such advice may not be seen as consistent with the Supplier Hub principle.

The most efficient approach to managing power factor is to invest in power factor correction equipment as close as possible to the source of the reactive power where this is economically justified. The current mechanism frustrates the achievement of this important objective because:

- It is only practicable to meter and charge the largest customers for kVArh – hence the generality of customers face no incentive
- Even where metered, suppliers may not pass on the DNOs kVArh charges
- The charge to an individual customer may not be sufficiently material to merit management time, or to justify investment in correcting power factor – particularly for those customers who do not have in-house engineering expertise

An alternative approach would be to incentivise DNOs to trade-off investment in power factor correction with other network investment.

Customer contact

The current regulatory framework has implicitly placed the responsibility for customer contact on electricity suppliers rather than electricity distributors (with the notable exceptions of connections, public safety and power outages).

A number of issues raised in the consultation document imply a broader DNO responsibility for customer contact, for example:

- Organising transmission access arrangements on behalf of DG (p2.27)
- Contracting with DG or demand in lieu of network reinforcement (p2.22)
- A more active role in community energy schemes (p2.38)
- A more proactive role in energy efficiency (p.2.41)
- Encouraging a more efficient use of the distribution network (with regard to power factor, for example) (p2.47)

Irrespective of the merits, or otherwise, of each of these areas, Ofgem needs to recognise that it will take time and funding for DNOs to rebuild the outward facing resources that were lost as a result of the business separation process and the historic focus on cost reduction.

Question 7: We have raised more detailed questions throughout the chapter. We welcome views on these issues.

1. Simplifying the connections process for distributed generation (p2.13)

We agree with Ofgem that the process/requirements set out in ER G59/1 and ER G75/1 must be proportionate and we will keep these under review as part of an ENA-managed process, beyond any modifications introduced by the current working group.

2. Standard national connection agreement (p2.12) and standard national process for DG connections (p2.13)

Since many DG connections (for CHP, micro-generation etc) are also demand connections, Ofgem's proposal for standardisation implies that it would cover all connections. We do not believe that this would be justified and the proposals do not seem to have been fully thought through. It may be more sensible to focus on establishing and communicating best practice rather than seeking standardisation.

3. Effectiveness of the current DG incentive (p2.9)

We believe that it would be wrong to judge the success of the DG incentive on the volume of DG connecting because there are so many other factors in play, such as planning consent issues.

The incentive was designed to minimise DNO expenditure on assets not included in the connection charge (i.e. assets whose cost is recovered through GDUoS). However, most DG connecting to our networks only requires the sole user element, and it is this element which can be prohibitively expensive – for example, providing a new line out to a windfarm located in a relatively remote location. On the other hand, most micro-generation systems will incur no connection costs at all.

DNOs are already under an obligation to offer the minimum cost connection scheme, so perhaps the incentive was unnecessary.

New demand connections tend to be close to existing infrastructure and so benefit from past investments. On the other hand, renewable DG must generally be sited close to its primary power source (wind, tidal etc) – areas where the benefit of past investment tends to be relatively limited. This leads to the relatively high connection costs referred to above.

At least in the absence of any firm indication of intent to develop future DG sites in a given geographic area, installing speculative network extensions ahead of need would clearly be inappropriate and would almost certainly lead to technically stranded assets. A way of redressing this issue would be to incentivise DNOs to work with research organisations and manufacturers, and invest 'ahead of need' – for example, by building spine networks onto which DG could connect. DNOs could earn higher rates of return for correctly anticipating such locations, but earn reduced rates of return where they got it wrong. In developing the necessary active network management enabling technologies to the point of commercial scale deployment, such technologies might then be available 'off the shelf', ready for deployment as and when firm indications of DG activity were received. Such technologies might then release additional network capacity and potentially reduce DG connection charges.

4. DG connection issues "where DNOs need to do more" (p2.17)

See our answer to question 3 above.

5. Extension of RPZ to include demand connections (p2.19)

As Ofgem notes, the take-up of the RPZ incentive has been disappointing. The RPZ builds on the DG incentive and so requires material non-connection chargeable costs before the incentive is relevant. As we have noted above, in our experience, costs of this type are generally not required for DG connections in our three DNO areas, so it is perhaps not surprising that there has been limited take-up of the RPZ scheme.

Nevertheless, we support the retention of some form of incentive on the deployment of technology, and would support the inclusion of demand customers within its scope. The inclusion of demand customers would allow DNOs to gain experience of technologies which enable demand side participation, for example by signalling a network constraint on an energy intensive manufacturing process.

6. Incentives on DNOs to consider non-network solutions (p2.22)

Investment in the network is driven by peak power flows on that network, so DG only avoids the need for capacity if it is guaranteed to run at this time of peak power flow (either by instruction or probabilistically, through diversity).

Nodal use of system pricing helps to reflect the value that DG can provide in deferring network reinforcement. However, unless nodal pricing is backed up by an agreement for the generator to be despatched by the DNO at times of system peak demand/network utilisation, it will not provide the optimal solution. In theory, this would mean that some otherwise economic distributed energy schemes would not go ahead.

We believe that it is possible to go further and consider more market-based arrangements to incentivise both the connection of distributed energy (DE) and demand side management (DSM), where this a lower-cost solution than network reinforcement. It would probably only be practicable – at least initially – to do this in respect of generators connected at EHV or at HV but close to EHV/HV substations.

The key features of such arrangements would be:

- The identification of trade-offs between network reinforcement and DE connections/DSM in selected 'time slots'
- Competitive auctions/tenders for DE/DSM 'time slots', including DE/DSM which is despatchable by the DNO (at times of system peak demand/network utilisation)
- Incentives for the DNO to make efficient trade-offs between DE/DSM and investment

The likely availability of DE (especially at times of system peak demand/network utilisation) would of course be an important factor. In drawing up such an arrangement, and in addition to any contractual obligation signed on to by the DE operator, account would therefore need to be taken of the guidance within ER P2/6 and ETR 130 for assessing generation availability (especially, but not only, in the case of intermittent generation). For some types of generation, and for most heat-led CHP applications, the DG will have limited availability and will therefore make only a small 'tradable' firm capacity contribution.

A precedent for such a scheme is the 'capacity output incentive' which will apply to gas distribution networks (GDNs) from 1 April 2008. This scheme combines obligations on GDNs to hold auctions for interruptible network capacity and an incentive to make efficient trade-offs between buying interruptions and reinforcing networks to accommodate peak load.

There would also seem to be scope to integrate the current RPZ arrangements with a market-based solution (i.e. integrate technical innovation with commercial innovation). For example, the DNO could auction DE 'time slots' with varying degrees of technical innovation, with additional incentives applying to capacity released through the use of innovative technologies.

7. Regulatory treatment of payments to DG/demand customers (p2.23)

Payments to generators in lieu of reinforcement should be subject to the same regulatory treatment as the costs of reinforcement itself. At present, the former would be treated as opex and the latter as capex and added to the RAV. Currently, marginal increases in opex are unfunded and marginal increases of capex are recoverable in accordance with the incentive rate derived from Ofgem's DPCR4 sliding scale incentive (now known as the Information Quality Incentive).

Elsewhere in its paper, Ofgem discusses the possibility of equalising incentives on capex and opex, which could have the effect of automatically addressing the issue of payments to generators.

8. Payments to related parties (p2.24)

Ofgem has suggested that payments made to related parties could create difficulties where the group owns DG and/or storage. We do not see any problem with a DNO making payments to a related party if appropriate regulatory controls are in place, for example:

- A published methodology for deriving such payments
- An enforceable non-discrimination rule in the making of such payments
- Reporting of all payments to Ofgem as part of the RRP process, including the reasons for selecting the relevant projects

In the interests of proportionate regulation, we would expect Ofgem to introduce the lightest regulatory touch and only resort to more onerous measures (including setting an incentive for independent DNOs free from related party generation and storage interests) should these prove necessary.

9. Roles and responsibilities (p2.28)

We support the introduction of the DNO-agency model.

Based on current levels of enquiries from DG developers, it is possible that relatively little DG will connect to our networks during the DPCR5 period; therefore, the impact of adopting the DNO-agency model is likely to be limited. However, we also note that this is a very uncertain area, and in recognition of this, we believe that the price control should include a suitable re-opener for such costs, should they prove to be material (say, cumulative costs of greater than 1% of average annual revenue). To do otherwise would significantly impact risk and hence our required return.

10. Treatment of legacy deep DG connections (p2.32)

We are unsure why Ofgem believes that past connection charging arrangements have any bearing on the future decisions of generators. Economic signals can only influence future costs, not those that are in the past. Any generator connected under a deep charging approach would face GDUoS charges in respect of any additional connections or any modification to their existing connections.

11. Current DG incentive (p2.33)

As stated above, we believe that there is a strong case for not retaining separate demand and generation controls on the basis that any negative payments to DG in lieu of reinforcement will be offsetting costs which would otherwise have naturally fallen on demand customers.

12. A more active role for DNOs in distributed energy schemers (p2.38)

Please see our response to question 1 above.

13. DNOs taking a more proactive role to promote energy efficiency (p2.41)

We believe that the role of engaging with suppliers on energy efficiency should continue to rest primarily with energy suppliers, as they have the more developed relationship with end-users. However, where an aspect of energy efficiency directly impinges on the operation of the distribution network, then it is possible to foresee a role for the DNO; principally, power factor management.

14. Appropriateness of a kWh driver (p2.42)

The kWh driver does not mean that DNOs actually deliver more energy. On the contrary, we have taken a number of actions that reduce the amount of energy delivered.

The unit driver, together with the losses incentive, has encouraged us to investigate anomalies in settlements data and have these corrected by the relevant supplier – action which helps reduce electricity consumption through the more accurate allocation of costs.

As highlighted in the consultation document, we accept that there are issues with the accuracy of the settlement system and that this raises concerns over the robustness of reported kWhs delivered. Given these concerns, it would appear sensible to remove this from the control to ensure that companies and customers are not exposed to the impact of random fluctuations in the reported levels of kWhs delivered.

The inclusion of a kWh driver, in conjunction with a customer number driver, in the price control, was to provide a mechanism to adjust revenues for variations in load-related reinforcement requirements, i.e. it was effectively a type of non-npv-neutral financeability adjustment. Looking forward, it should be replaced by volume drivers across the most uncertain aspects of capex (such as DG-related investment).

15. Metering (p2.43)

Ofgem makes no mention of the asset stranding issue associated with any accelerated roll-out of smart meters.

The rationale for allowing DNOs to recover their stranded costs in such circumstances is unambiguous. DNOs provided meters at a regulated cost of capital which did not remunerate the risk of widespread stranding as a result of politically driven technological change.

Some stranding protection was provided for prepayment meters at DPCR4 because of supplier initiatives to remove token meters. We do not see any difference in the fundamental price control logic behind stranding caused by the introduction of a more modern prepayment meter and stranding caused by the introduction of smart meters.

16. Educating customers on power factor (p2.47)

Please see our response above.

17. Proportion of technical loss reductions due to DNO action (p2.53)

EDF Energy Networks has taken a number of steps to reduce losses, both technical and non-technical.

Technical losses

There is limited scope for cost-effective network investment to reduce losses. This is due partly to the sheer scale of distribution legacy networks and also to the fact that networks have, in any case, been historically designed to take due account of the economic cost of losses.

However, while network investments aimed purely at reducing losses will rarely be economically justified (or indeed justified in terms of overall carbon cost), opportunities for reducing losses at relatively low incremental cost do exist. The following are abbreviated extracts from EDF Energy Networks' Technical Losses Reduction Strategy.

<u>Rationalisation of HV and LV cable sizes</u>

The majority of copper (variable) losses occur on 11kV and especially LV networks. Rationalisation in cable sizes has resulted in larger cross-section cables (i.e. less tapering of feeders) and hence lower losses, as well as procurement scale-economies. Larger cross-section service cables ($35mm^2$) are particularly beneficial due to the 'peaky' nature of customer demand profiles.

<u>Lower loss transformers</u>

We specify the latest laser-etched steel core technologies for our power transformers, giving lowest economically justifiable iron (fixed) losses (based on long-run DCF analysis and fully valuing the losses over the lifetime of the transformer, not just the known life of the incentive). Low loss distribution transformers are also now used for all new connections requiring a new substation or transformer replacement.

<u>LV ABC re-conductoring</u>

Variable losses on LV networks are greatly increased where load is imbalanced. Rural three- and four-wire networks are particularly susceptible. Therefore, in rolling out the LV ABC programme we have taken particular care to ensure equal distribution of connections across phases, optimising losses in the phases and minimising losses in the neutral conductor.

Voltage rationalisation

As part of our ongoing primary network development strategy, we continue to rationalise voltage levels and reduce the number of voltage step changes. We apply direct 132/11kV transformation where load density is high, for example in central London where we are also gradually eliminating intermediary voltages such as 66kV and 22kV. As well as removing high loss transformers, reducing transformation stages (and hence the number of transformers) reduces overall iron losses.

HV OHL resilience works

HV OHL refurbishment/strengthening work involves the replacement of small cross-section conductors with modern, heavier cross-section types. Care is taken to ensure that single-phase spur connections are evenly distributed across the three phases of the main line, and in some cases single-phase spurs have been upgraded to three phase. As well as improving resilience, this also improves voltage regulation and reduces variable losses.

The above are just some of the opportunistic actions we take to cost-effectively reduce (or minimise) technical losses as part of our overall asset renewal investment.

Reactive power charges

To encourage larger commercial/industrial customers to improve their power factor, we include in our DUoS tariffs, reactive charges where the customer's power factor falls below certain thresholds. We apply the charges at two levels: (a) for pf <0.95 and (b) a higher charge where pf <0.75. Reducing reactive flows reduces upstream variable losses.

Although we take account of losses' impact in individual engineering decisions, we do not keep an overall tally of the proportion of observed losses reduction which is due to these actions. To do so would require a significant metering infrastructure to track actual changes in losses compared with distributed demand.

Non-technical losses

We have put in place extensive arrangements to identify units not entering settlement, and to encourage suppliers to take corrective action.

We believe that this is a valuable service which DNOs can and should provide to the electricity industry. By improving the quality of settlements data, cost signals to generators, suppliers and consumers is improved, thus contributing to improved allocative efficiency in the economy.

Ofgem, through its work in revenue protection activities, is aware that the current settlement arrangements do not place unambiguous incentives on suppliers to declare all units, because any error will be shared among all suppliers in a GSP area via the operation of the GSP Group Correction Factor.

However, DNOs are currently subject to very clear incentives, both through the unit driver and the losses incentive. In changing these incentives (which have their own issues – discussed elsewhere in this response), Ofgem should ensure that there remains a clear incentive on DNOs to reduce non-technical losses.

We have actively targeted the reduction of non-technical losses through a suite of activities aimed at improving the quality of data used in the industry settlement processes:

- Within our Income Management function, a dedicated team of 25 conducts analysis of available settlement data to identify suspect consumption data, together with a further 15 in our field activity service provider
- Site visits are undertaken where we suspect settlement data to be under-recording consumption. Currently, in excess of 50,000 visits are conducted each year
- We have also invested around £3m in software to help manage the data and prioritise investigations
- A programme of audits of customers' unmetered supplies inventories has been initiated, targeted at improving the accuracy of consumption data used for settlement purposes

In addition, EDF Energy Networks actively pursues revenue protection (theft) investigations with a team of 40 (within CFS) on behalf of most suppliers.

Of course, unrecorded consumption has often arisen over many years, and when this enters settlements, any prior year units will have the effect of reducing losses in the current period.

Data management incentive

If the existing incentive (the unit driver and the losses incentive) were to be withdrawn, we would propose that a new data management incentive be launched in its place. This could take the form of a pence per £kWh reward for units found and (as confirmed by suppliers) entered into settlements. The co-operation of suppliers in such a 'receipting' scheme could be promoted through changes to the DCuSA, or possibly through a new licence condition for suppliers.

18. Taking account of unmetered suppliers (p2.54)

We do not believe that moving DNOs to a common position would have any material effect on the outcome of the current losses incentive.

19. Options for incentivising losses (p2.60)

Please see our response above.

20. Incentives on SF6 (p2.66)

Please see our response above.

21. Incentives on fluid-filled cables (p2.72)

Please see our response to question 4 above.

22. Undergrounding in AONBs (p2.77)

The AONB scheme has been very popular with our stakeholders and we would be happy to see it continue, and even for it to be extended, provided there was customer support for it.

As customer willingness to pay will be established quite soon by Ofgem's survey, this should allow early confirmation of DPCR5 funding levels, thus facilitating continuity of activity.

There are a few technical improvements which could be made to the scheme:

- Firstly, to assist the AONBs we have provided a full-time project officer, a role that the AONBs strongly support. However, the costs of this activity are allocated to opex and are currently unfunded, i.e. EDF Energy's shareholders are bearing the cost.
- Secondly, the per kilometre allowance should be updated to reflect the actual cost of schemes executed in the DPCR4 period.
- Thirdly, we suggest that it would be sensible to include projects for undergrounding overhead lines which are not within but are clearly visible from AONBs.

23. Other carbon footprint activities (p2.78)

We have noted above the importance of non-technical losses management on cost allocation. Improved cost allocation will contribute to carbon reduction by ensuring that the costs fall where they are due.

We do not believe that Ofgem has omitted any other activity which can have a material impact on a DNO's carbon footprint.

24. Carbon footprint measures used by DNOs (p2.82)

Please see our answer to question 2 above.

Customers

Question 1: Do the current regulatory arrangements deliver the levels of service that customers expect?

In addition to the views being expressed by customers through Ofgem's customer survey, we have identified a number of issues which we believe are of particular concern to our stakeholders. To find out more, we have included the following questions in our DPCR5 stakeholder consultation document:

1. About EDF Energy Networks:
   Do you have any general comments you would like to make about our Planning for the Future document?
2. The Future Business Environment:

   What are your views on the assumptions we have made with regard to the key issues that we have identified for the future of the electricity industry?
3. Cost Pressures on Resources :

   Do you have any comments on how we could manage issues around the volatility of raw material prices?
4. Providing a Safe, Secure and Efficient Network:

   Do you have any general comments on our proposals contained in Section 5?

   - How we have reflected regional growth in our network development plans
   - How we are proposing to improve the resilience of the network against storms
   - What we are doing to improve network reliability and reduce customer interruptions
   - How we are going to work to minimise the level of disruption caused to the public by replacing the network
   - How we are making it easier for customers to connect to our network
   - How we are going to improve customer service
   - How we are ensuring that the public is kept safe around our network
   - Fluid-filled cable decommissioning
   - How we have improved relationships with our contractors
   - The pricing implications of our plans
5. Improving the Networks' Resilience to Storms:

   To what extent should we increase our investment to further protect your power supply?

6. Quality of Service:

   To what extent do you think we should broaden our measures of quality of service (QoS) to include additional customers, for example our remote customers?

7. Fluid-Filled Cable Decommissioning:

   To what extent should we change our investment plans for fluid-filled cable decommissioning?

8. Undergrounding Cables in Areas of Outstanding Natural Beauty:

   To what extent should we change our investment plans for the undergrounding of cables in Areas of Outstanding Natural Beauty?

9. Planning for Uncertainty :

   We believe that increasing network resilience for High Impact Low Probability events is a key issue that currently lies outside our current regulatory plans; to what extent should this be core to our DNO investment plans in future?

10. Protecting the Future of the UK Economy:

    What impact do you think the current arrangements for the provision of new electricity infrastructure is having on economic growth?

11. Protecting the Future of the UK Economy:

    What changes to the charging methodology for new connections would you like to see?

12. Building for a Sustainable Future:

    To what extent should network operators be targeted to reduce their direct impact on the environment?

13. Building for a Sustainable Future:

    To what extent should network operators be given incentives to address the skills gap and to build a sustainable industry?

14. Providing Good Value for Money

    Do you have any general comments on this section?

15. Investing for the Future – New Technologies:

    To what extent should the current funding arrangements for research into new technologies be extended to their deployment?

Our DPCR5 consultation will be open from 1 July to 28 September and further details can be obtained from www.edfenergy.com/dpcr5

Connections

Within our DNO service areas there are a number of specific geographical areas where we are encountering exceptional growth in new electricity demands, and hence an exceptional demand for new/reinforced assets. Many of these demands are the result of connection applications for large data centres, each with an electrical demand of between 25MW and 50MW.

These connections typically require costly reinforcement of higher voltage networks and, because there are multiple applicants, there is an issue with how these costs are met. In particular, the first comer is often unwilling to meet the full costs (the approach required by the Electricity Act s19 regulations), and we are being criticised for not providing higher voltage infrastructures ahead of need (something which the regulatory framework requires us not to do).

We believe that the current regulatory, and specifically connection charge, environments do not provide sufficient flexibility to respond effectively to our customers' requirements.

During the current period we have explored a number of potential routes to try to provide flexibility to customers. In particular, we have explored the option of creating an affiliate IDNO to provide a more flexible approach consistent with competing non-affiliate IDNOs and DNOs which operate outside of their service areas. However, Ofgem has not facilitated this route by seeking to put licence conditions on the relevant DNO/affiliate IDNO which have the financial effect of imposing the DNO's connection charge methodology on the affiliate.

We have also considered arrangements for the future apportionment of development costs and the appointment of a lead developer. However, none have provided customers with sufficient flexibility and reassurance that there will be no future short-term restriction of economic growth due to lack of network capacity.

We have included this issue in our stakeholder consultations because it is clearly something that stakeholders (developers, local government etc) are very concerned about.

Of course, this "queuing" issue is not new. It is, essentially, similar to the problem that the transmission companies face in respect of applications to connect renewable generators. It may be the case that EDF Energy Networks, and DNOs generally, will experience similar problems should significant numbers of windfarms seek a connection to distribution networks.

While we would not advocate speculative development in cases where there is clear evidence of future need, for example from RDA development plans, it may be possible to develop a scheme whereby a DNO can build infrastructure ahead of need provided that the risk of doing so is not entirely passed on to customers.

In such cases, the DNO could be rewarded for making the right choices, and penalised for building assets that become stranded. We would welcome the opportunity to develop such an approach with Ofgem.

Elsewhere in this response we propose the enlargement of the RPZ scheme to include a limited amount of deployment of new technologies. This would complement the proposed scheme above by incentivising DNOs to deploy technology to avoid building assets.

Question 2: Is the focus and scope of the current regulatory arrangements correct and are there any gaps that need to be addressed?

Generally yes, but we have identified a number of improvements to the quality of supply target setting process; these are set out below.

Question 3: Are DNOs customer focused enough or should they be doing more to improve communication with customers?

Our response to this question is set out below.

Question 4: Is DNOs' financial exposure set at the right level and/or do we need to change the emphasis in certain areas?

We believe that the current level is about right.

Question 5: Do you think we have identified the right issues and appropriate areas for development with the existing incentives?

Yes. Our detailed answers to the specific questions raised are shown below.

Question 6: We have raised some detailed questions throughout this chapter. We welcome views on these issues.

1. *Is a complaint handling standard required for the DNOs? (3.21 & 3.39)*

No. The DNOs should be given the chance to demonstrate that they have effective complaint handling procedures in place. DNOs are already under a licence obligation to prepare and publish complaint handling procedures, and to have them in place as part of their (currently voluntary) ombudsman arrangements. Regulation should be introduced only if these arrangements prove to be ineffective.

2. *Should the IIS provide incentives for DNOs to improve service for customers who experience a below average quality of supply? (3.25)*

This depends on customers' willingness to pay for improvements compared to the cost of achieving them.

The cost of improving quality of supply will fall on all customers, and the DNOs will bring forward improvement schemes consistent with the value of the incentives they face. Typically, this will mean that the DNOs will progress improvements that have the most favourable cost-benefit. Those customers who do not see improvements will be those served by networks where the cost of service improvement exceeds the benefit.

Since networks serving the worst-served customer group are generally the most costly in terms of per capita cost of quality improvement, customers as a whole must be willing to pay for the necessary improvements.

Some might see this as burdensome; however, we recognise that there are also issues with equality of service and, like Ofgem, we feel that there should not be too wide a gap between average and lowest-served levels. We would therefore support an incentive aimed at reducing this gap.

Option 3 offers the best way forward. To begin with, this would need to be triggered by reported performance at the HV circuit level (we note that some companies (SPN and LPN) had voluntary schemes in place during the DPCR2 period).

The remaining two options as presented by Ofgem lead to substantial costs of nuisance:

- Option 1 (tighten existing GS2 to 12 hours) is impracticable because excavation would need to take place at night time to repair underground faults (the noise this would cause would be unacceptable to the local community). However, we recognise from Ofgem's customer survey that this issue is one which customers are concerned about and appear willing to invest in. Therefore, the key task is to better quantify what DNOs can deliver for the additional levels of expenditure that customers are willing to fund.
- Option 2 (GSS based on cumulative minutes lost per customer) is also impracticable because it would require a phase-connectivity model of the sort that has previously been rejected on cost grounds (during the development of the multiple interruption GSS).

3. Is the move from longer to short duration interruptions desirable? (3.26)

The introduction of full-scale automation does not typically reduce the absolute number of interruptions (long or short), but does very significantly reduce their duration. It is therefore self-evident that customers have benefited from the move to shorter interruptions and would not want to see the situation reversed.

4. To what extent should exceptional events be removed from the IIS (3.28)

In our view, the current arrangements are working well and there is no strong driver for significant change.

We believe that the scheme can be improved by introducing a materiality threshold relating to lightning events. This would reduce the number of small-scale claims made by some DNOs.

5. Are there other ways to encourage DNOs to communicate with customers and local communities (3.31)

Apart from other engagements with our customers, for example holding meetings with parish councils to outline proposed projects to improve quality of service, our DPCR5 stakeholder consultation is, we believe, an excellent example of customer engagement. However, an important principle is that if we engage with customers and they express a strong preference for, say, a different level of service (such as High Impact Low Probability), the regulatory framework must facilitate the necessary cost recovery.

For example, we will be asking our stakeholders in London whether they would favour a higher level of network security for the more central parts of the network, recognising the important contribution that certain areas of London make to the national economy. Analysis has shown that a 'high impact low probability' event in a central business district might give rise to a level of economic loss way in excess of the cost of reinforcing the network to mitigate such an event.

As customer communication is also included within the ambit of the Electricity Distribution Customer Service Reward Scheme, perhaps a further route to encouraging DNOs to survey customers already exists.

6. Approaches to automated messaging (3.32)

As the data protection issues still exist, we cannot see a practicable way forward.

7. Incentivising unsuccessful calls (3.33)

Provided it could be measured reliably across all companies, we would support the financial incentivisation of this aspect of customer service.

8. Coverage of GGS (3.35)

We believe that the package of GSSs remains appropriate.

9. Compensation levels for business customers (3.36)

It is possible that business customers incorrectly believe that the GSS scheme is intended to compensate them for economic loss rather than provide an incentive for the DNO. However, a compensation scheme would either need to be funded by customers, or customers would need to fund the DNO's costs of avoiding payment of such compensation. This would effectively amount to consumers generally providing insurance for business impacted by a supply interruption. We do not believe this would be the most efficient outcome because (a) it would be a cross-subsidy between consumers, and (b) business consumers are better placed to negotiate insurance arrangements (and/or invest in appropriate UPS systems) that reflect their particular circumstances.

In any case, if a business customer suspects negligence on the part of a DNO, the business can pursue compensation through the established legal channels.

10. Connections (3.42)

Ofgem notes that some customers express concern about the quality of service they receive from the DNOs regarding the provision of connections to the network. We share Ofgem's concern.

Clearly, the responsibility for improving connections service levels lies with the DNOs. However, we do not believe that the price control framework has supported improvements in service. In particular, Ofgem's DPCR4 approach to setting cost allowances for connections (the 'CSV' approach) paid no regard to the drivers behind connection costs (such as the volume of enquiries and the volume of projects implemented). Indeed, we understand that some companies had excluded the indirect costs associated with contestable activities from their cost forecasts and that this fact was not picked up in Ofgem's cost assessment! Therefore, any connections business that is more active than the DPCR4 cost-frontier companies (and given the relative GDP growth in the South East of England, EDF Energy Networks is firmly in this camp) will have had inadequate funding for their connections business.

Ofgem raises a number of potential measures it could introduce for connections, some of which appear disproportionate:

- Regulating the level of connection charges for domestic customers (or other customers not protected by competition) is unnecessary as they already have statutory recourse to determination. In any case, price capping these connections would only be necessary if Ofgem had evidence that prices were above efficient cost levels – we are not aware of such evidence.
- The structural separation of DNO connections businesses could deprive the DNOs of operational synergies, which would raise costs for consumers and could reduce operational capability during emergencies. The removal of economies of scope, in order to promote competition, would probably not satisfy Ofgem's statutory duty to promote such competition only where it is 'appropriate'.
- Greater incentives and/or revised licence conditions with respect to, say, provisions of quotations, might be appropriate provided that connections businesses are properly funded through the price control.

We also believe that before embarking on further measures to support the development of competition, Ofgem should assess whether the competition that has emerged so far is 'appropriate' competition. It is our belief that IDNOs, despite the imposition of relative price regulation for domestic customers, generally increase costs for consumers in order to fund discounts to developers – a problem which will not be solved simply by the DNOs introducing more cost-reflective 'IDNO' DUoS tariffs. This issue is discussed further below.

The regulation of IDNOs

This section discusses the emerging economics of the IDNO market and the reasons why Ofgem's current policy in respect of IDNOs and affiliate IDNOs is unsustainable in the longer term.

In our experience, developers choose an IDNO solution because the IDNO is able to offer them a discount compared to the connection charges that would have been levied by the local DNO had it provided the connection. So, a key question for Ofgem is how these discounts are funded.

IDNOs have a relative price cap on them in relation to domestic customers and so cannot levy DUoS prices above those of the local DNO in respect of this group of customers. However, this restriction does not apply to *non-domestic* customers, so it is possible that the discounts are funded by increased prices for this group.

An IDNO may be able to fund a discount because it has lower costs than those which the local DNO includes within its DUoS prices only (i.e. the costs included within its price control). There could be three broad reasons for this:

(1) It is more efficient than the local DNO (perhaps because of economies of scale obtained through engaging in multi-utility activity)

(2) The local DNO faces additional costs not faced by the IDNO

(3) The assets required for the IDNO connection are less than the average assets, the cost of which is included in the local DNO's DUoS charges

(1) <u>It is more efficient than the local DNO</u>

Clearly this is possible, although, given the economies of scale and scope available to the local DNO, we would not expect there to be a significant difference between DNO and IDNO.

(2) <u>The local DNO faces additional costs not faced by the IDNO</u>

There are a number of significant areas where the DNO faces additional costs which will not be faced by the IDNO in the short and medium term (if at all).

- Recovery of pension scheme deficits – new entrants will not have pension deficits.
- Administration of a connections business (largely included in DNO opex under the DPCR4 arrangements) – IDNOs are unlikely to need to process requests for connection within their sites since new premises will have just been connected.
- Underground fault repair – the local DNO has an ageing asset base which causes significant costs of repair; costs which will not be incurred by the IDNO in the short to medium term while its network is new.

- Accelerated regulatory depreciation – IDNOs are free to have longer depreciation lives, thus reducing costs in the short term.

Clearly, some of these categories are about the timing of costs rather than their absolute level; but, of course, the NPV of costs reduces them the further into the future they are deferred.

The assets required for the IDNO connection are less than the average assets, the cost of which is included in the local DNO's DUoS charges.

The local DNO's DUoS charges are set to recover the average assets required to transport electricity from the grid supply point down to the boundary between the distribution network and the sole-user connection assets. These charges are disaggregated into HV and LV by reference to the average assets required to supply each customer group.

Where the costs of an IDNO's network are lower than the DNO's HV to LV price differential, then an amount is available to fund discounts.

Discussion

Ofgem's principal statutory objective is to protect the interests of consumers through competition where appropriate, and it would be reasonable to assume that competition which raises prices for consumers could not be considered appropriate.

Referring to the above analysis, only the first of the three categories seems to have any prospect of reducing costs for consumers. The other two increase costs and could not, therefore, be said to lead to 'appropriate' competition.

It could be argued that the 'averaging problem' could be addressed by DNOs introducing 'IDNO' tariffs. However, in practice these would have limited effect since the IDNOs' assets are typically those which a DNO would class as sole user and include in connection charges.

Conclusion

In establishing its policy on affiliate IDNOs (IDNOs who are part of the same group of companies as a DNO), Ofgem expressed concern that the group would direct lower than average cost connections to its IDNO and retain higher than average cost connections in its DNO, thus raising costs for consumers overall. So, presumably, from this it is reasonable to assume that Ofgem broadly agrees with the analysis presented above.

However, the problem will not go away if the IDNO is not affiliated to an IDNO, since all IDNOs who provide discounts to developers by definition increase costs for customers, unless those discounts are funded solely through superior efficiency.

This analysis raises two important regulatory questions:

1. It is appropriate for Ofgem to promote a model that might ultimately result in higher costs for customers; and
2. Should Ofgem not reconsider its position and permit DNOs to compete on an equal basis within their distribution service areas.

11. Margins on connection charges (p3.45)

Ofgem appears to reject any change on the grounds that competition is not yet effective. However, it is difficult to see how it will ever be effective if new entrants (ICPs) are forced to compete against an incumbent required to charge at cost.

We have taken legal advice as to whether the current arrangements are consistent with the Competition Act and we are advised that the test for predatory pricing is normally where prices are substantially below cost. Nevertheless, we do not consider the current arrangements to be satisfactory and we ask Ofgem to reconsider its position.

12. Details of DNO customers research programmes (p3.7)

At EDF Energy Networks we see robust engagement with our customers as an essential component of our business practice. The extensive dialogue we carry out with a wide range of groups and organisations representing our customers helps us to improve our business performance. For example, we engage with MPs and Government ministers who are at the forefront of the UK energy policy debate. We also listen to the challenges encountered by our major energy customers, with whom we regularly discuss our current performance to ensure we understand their electricity needs and any associated issues.

We have developed relationships with our major customers in each of the regions we serve. We discuss regional development plans and work together to ensure capacity is available for new developments and is upgraded where required.

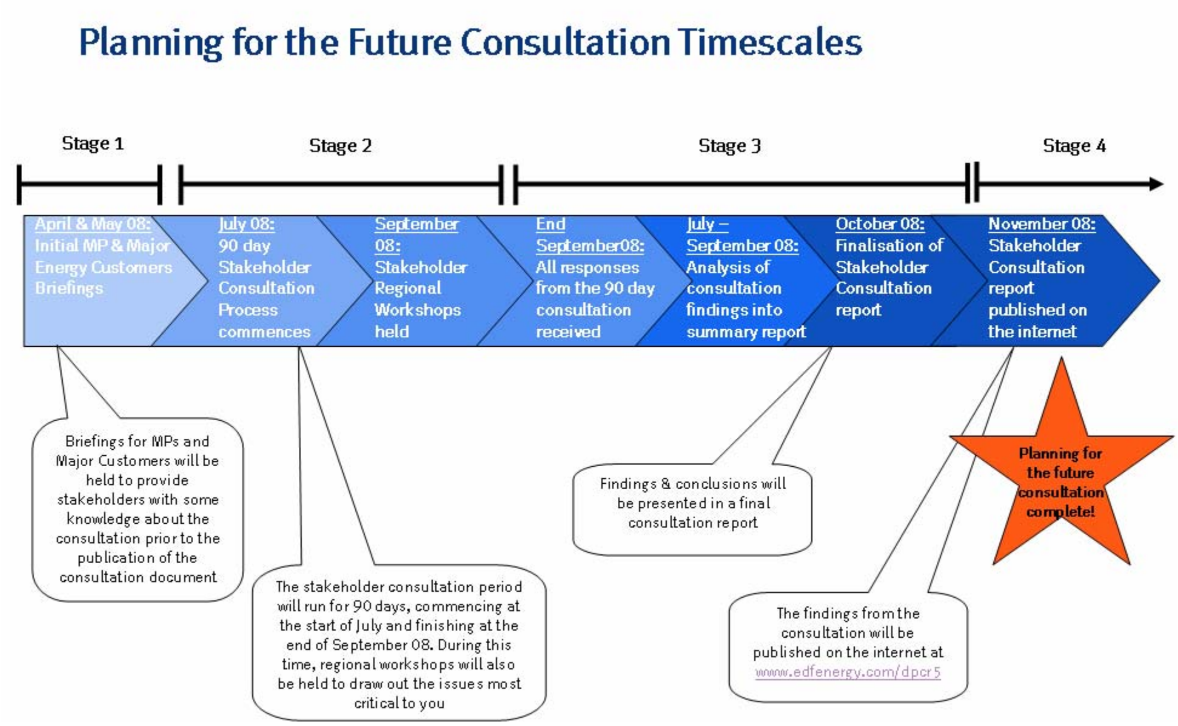
Our 90-day DPCR5 consultation period commences on 1 July. Prior to this consultation process we held targeted discussions with many key customers in an attempt to understand the issues they face. In 2006 we appointed a group of leading experts to provide a healthy, independent challenge to the development of our business approach and strategy. The Stakeholder Advisory Panel includes eminent individuals with broad experience in business, community relations and the environment.

This panel hosted a key stakeholder briefing to elicit the issues faced by our key energy customers, and we also held face-to-face meetings with politically interested parties at an MP drop-in centre at the House of Commons. Some of the initial views that were raised in our ongoing engagement and pre-consultation meetings are listed below:

- Reliability of power and network resilience if unpredictable events occur

- The effects of increasing energy demands on reliability
- Sustainability of power and sources of electricity over the next 20 years
- The reduction of our carbon footprint and promotion of distributed electricity generation
- The role of renewable and nuclear energy sources in the future
- Value for money
- The focus of future investment in the network
- Protecting our Areas of Outstanding Natural Beauty

The illustration below highlights the timescales that our consultation will follow, the results of which will be available to Ofgem in a final consultation report in November 08.



14. Other improvements to the Interruptions Incentive Scheme (App7 1.2)

We agree that it would seem sensible to combine LV service and mains interruptions in the benchmarking process. However, we are concerned that the current LV benchmarking process disadvantages LPN. The reason for this is that the restoration process for an underground cable damage fault generally requires excavation in the footpath/road to undertake the required repair. This significantly increases the time to restore customers when compared to an overhead line damage fault. Unlike all of the other companies, LPN's LV network is wholly underground and hence there is no diversity in the mix of faults used to calculate the benchmark. There are two possible options for resolving this issue:

- Option 1 – split the LV benchmarking into overhead, underground and possibly non-damage sub groups, and calculate individual benchmarks for each category. These would then be re-aggregated to produce an overall LV target
- Option 2 – derive an LPN-specific adjustment

Given Ofgem's desire to not radically alter the benchmarking methodology, our preference is option 2. This is also likely to be the simplest to implement.

With respect to the HV benchmarking methodology, our key concern is that the process disadvantages those companies who have invested in automation. This is due to the fact that, as the volume of automation on the network increases, the CML per CI also increases. The reason for this is that as automation levels increase, more customers are restored within three minutes (i.e. the long interruption is converted to a short interruption), leaving only those customers for whom a repair of the network is required within the benchmarking calculation. This impact is shown in the graph below. The graph details the year on year change on CML per CI against the volume of short interruptions due to automation.

In our opinion, it remains appropriate to include pre-arranged CIs and CMLs within the incentive scheme, as this encourages efficient work management. We would expect Ofgem to discuss with each of the DNOs their forecast requirements for planned CIs and CMLs, and the DNOs will be required to provide evidence to support their submission. Given that there are different methodologies used to calculate the respective targets, we can see merits in planned CIs and CMLs being separated from unplanned CIs and CMLs. If the planned CIs and CMLs are treated separately, consideration should also be given to applying a lower incentive rate, as customers tend to value planned interruptions differently from unplanned ones.

We agree that frontier CML performance should be rewarded. However, CI frontier performance should also be rewarded. Our view is that the frontier companies should be given an allowance for accepting a harder target than the benchmarking suggests, as this preserves incentives to maintain the current levels of service provided to customers and to seek further improvements. We continue to believe that it is appropriate for DNOs to be funded to achieve service improvements, assuming customers indicate a willingness to pay for them. However, we agree that customers should not have to pay twice for improvements. Therefore, any future allowance should be based on the movement required from the current DPCR4 targets to the new DPCR5 ones.

15. Should thresholds change (App7 1.45)

In general, we believe that the exceptional events mechanism has worked well. Ofgem's concern that the exclusion of these events could reduce companies' incentive to perform well during such events is unfounded. Notwithstanding the fact that we endeavour to provide the best levels of customer service at all times, exceptional events tend to draw the greatest public scrutiny and poor performance during such events can have significant reputational damage. However, we do believe the process can be improved and would support the introduction of a materiality threshold for lightning events.

We would also support the introduction of a maximum cap for GS payments under the normal weather standard, as this would align it with the severe weather standard.

16. Changes to telephony survey (App7 1.6)

We accept that there is a certain degree of duplication in the current survey and support the proposed simplification. In principle, the new questions look sensible, but we agree that it would be wise to trial them in DPCR4.

17. AoNBs (App7 1.75)

Our views on the development of the AoNB scheme are covered in the environment section above.

Networks

Question 1: Have we captured all the key lessons learnt from DPCR4 regarding cost assessment?

In part.

While all forms of cost benchmarking/modelling are imperfect, the approach used at DPCR4 discriminated against some companies:

1. The composite scale variable (CSV) did not reflect the main cost drivers for DNOs; in particular, it did not capture the indirect costs of delivering large CAPEX programmes, nor did it capture the costs of operating a busy connections business.
2. The controllable cost benchmarking was only based on one year's data.
3. There was no meaningful bottom-up analysis, and what was done was not used.
4. Ofgem made unsubstantiated assertions about future frontier shift.
5. Controllable costs were not submitted on a consistent basis or properly normalised by Ofgem (for example, some DNOs did not declare connections indirect costs relating to contestable connections activity – a major flaw in the calculations)
6. Allowances for regional costs were inadequate and were not based on the evidence
7. Ofgem's consultants had insufficient time and budgets to properly review DNO capex programmes (and the consultants sometimes appeared to make asymmetric adjustments to their modelled outcomes)

Of these, the main outstanding areas of concern are in respect of 5 and 7 above, i.e.:

While the RRP has greatly improved the quality of reporting, there are still many anomalies which need to be resolved. Ofgem should not hesitate to use its compliance powers where a DNO has failed to comply with the RRP rules.

We remain concerned about the amount of technical resource Ofgem retains in-house, and we not aware that Ofgem has appointed consultants.

Question 2: Is our approach to cost assessment appropriate?

In principle, yes; however, it is described at a high level and it is currently unclear how the various elements will be combined to produce a robust result. For example, Ofgem has indicated it will use a range of techniques (which we support), for example:

- Regression
- DEA
- Panel data
- Bottom-up

We are concerned about how Ofgem will blend the results coming from these techniques to produce a credible result. We are aware that CEPA are doing work for Ofgem in this area and it would be useful to know when the results of their work will be published.

We would encourage Ofgem to be clear about how the various process elements fit together and set these out in a detailed timetable (for example, we are unaware of the scope and timing of any bottom-up benchmarking).

Question 3: Are there alternative approaches to cost assessment that we should be considering?

No.

Question 4: How might our approach to benchmarking be improved?

We have noted the deficiencies of the DPCR4 work above, and it is clearly important that Ofgem addresses these. The key aspects to get right are:

- Normalising costs of any DNO not complying with the RRP rules
- Identifying appropriate cost drivers
- Having a robust and transparent process for using the output of the various econometric techniques used

Question 5: Have we captured all the key issues for "networks"?

We continue to believe that there must be explicit links between the Long Term Electricity Networks Scenarios (LENS) project and DPCR5 since it is not appropriate to set allowances through to 2015 without agreeing on the overall strategic direction DNOs are expected to take. For example, where LENS identifies a range of plausible strategic outcomes, but the choice is currently not clear, the price control should strive to provide DNOs with a suitable degree of flexibility.

Question 6: Is our building block approach to forecasting appropriate?

Yes. However, an important question is how Ofgem will avoid creating an unsustainable 'virtual DNO' when combining its analysis on the respective building blocks. Clearly such a combination should take account of the degree of error inherent within each building block.

Within the proposed building-block approach to forecasting future network requirements it is important that Ofgem does not lose the comparator data developed through the annual RRP submissions. We therefore do not believe that it is appropriate to change the format of data collected during the current price control review process. We consider it more appropriate to change the data submission requirements and definitions as a result of the lessons learned in the current distribution review for future data submissions beyond DPCR4.

Question 7: What is the scope for developing additional outputs measures and how can these be incorporated into the price control?

Ofgem already collects information on the direct outputs of a distribution network, i.e. those which are immediately visible to customers. We believe there is little scope for development here.

Ofgem should also collect information on the indirect outputs, i.e. those with a less immediate effect on customers; for example, those areas that can provide a proxy for network risk.

One of the weaknesses of the DNO regulatory framework is that price controls are set without reference to the underlying asset risk, and this can seriously undermine the benefits of benchmarking and peer comparison – in developing capex modelling, for example.

The main categories of information that provide a proxy for asset risks are:

- Asset utilisation
- Asset condition
- Asset age

We would support the development of a joint definition of asset condition categories and also asset useful lives. Investment plans could then show, for each company, the impact of these measures over time. This could form the basis of a longer-term regulatory approach to network investment which would increase certainty and reduce risk.

It is also possible to develop measures which act as proxies for the discharge of CO_2 and or other greenhouse gases into the atmosphere. We cover these in our answers to Ofgem’s environmental questions.

There may be other outputs which Ofgem needs to collect in order to support improved drivers for cost benchmarking. Ofgem and the DNOs should review the improved benchmarking that we expect to be a feature of DPCR5, and put in place RRP arrangements to capture these in a robust manner.

Question 8: What is the best way for DNOs to gain stakeholder input to their forecast business plans and how should Ofgem facilitate/incentivise this?

We believe that the approach Ofgem has taken is a good one.

We see little point in DNOs being responsible for customer willingness to pay analysis. This should be, as it is, a collaborative exercise between the regulator and the industry. In this way, both sides can be suitably confident in the results of the analysis. Where DNOs can play a more independent role is to engage with the various interest groups within their particular areas.

It will be important to give consideration to the legal basis relevant to the weight a DNO gives to the various stakeholder respondees. Our initial view is that DNOs should assess responses in relation to their section 9 duties (of the Electricity Act 1989) to:

- Develop and maintain an efficient, co-ordinated, and economical system of electricity distribution; and
- Facilitate competition in the supply and generation of electricity.

Of course, these duties are not the same as those on Ofgem (primarily to protect the interests on consumers wherever appropriate by promoting effective competition), nor are they the same as the duty on the Competition Commission to protect the public interest. It is therefore possible that both Ofgem and the Competition Commission will validly draw different conclusions from the stakeholder process to those drawn by the DNOs.

It would be helpful if Ofgem set out its views on the above.

Question 9: Is the IQI and capex rolling incentive the best way to ensure realistic forecasts and efficient investment?

The sliding scale incentive introduced at DPCR4 (now known as the IQI) was a valuable tool for resolving differences of opinion on future capex needs.

We believe that Ofgem should revisit the calibration of the IQI. At the GDPCR, a company which proposed a level of capex greater than Ofgem's forecast but nevertheless spent at its forecast level (and such expenditure was deemed to be efficient and entered the RAV), would still receive a penalty. For example, a GDN which bid £125m against Ofgem's forecast of, say, £100m, and then spent efficiently, would face a penalty of £5.94m. Ofgem's GDPCR matrix is reproduced below for ease of reference.

GDN:Ofgem ratio	100	105	110	115	120	125	130	135	140
Efficiency incentive	40.0%	37.5%	35.0%	32.5%	30.0%	27.5%	25.0%	22.5%	20.0%
Additional income	2.50	1.97	1.38	0.72	0.00	-0.78	-1.63	-2.53	-3.50
Allowed expenditure	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Actual expenditure									
70	14.50	13.69	12.75	11.69	10.50	9.19	7.75	6.19	4.50
80	10.50	9.94	9.25	8.44	7.50	6.44	5.25	3.94	2.50
90	6.50	6.19	5.75	5.19	4.50	3.69	2.75	1.69	0.50
100	2.50	2.44	2.25	1.94	1.50	0.94	0.25	-0.56	-1.50
105	0.50	0.56	0.50	0.31	0.00	-0.44	-1.00	-1.69	-2.50
110	-1.50	-1.31	-1.25	-1.31	-1.50	-1.81	-2.25	-2.81	-3.50
115	-3.50	-3.19	-3.00	-2.94	-3.00	-3.19	-3.50	-3.94	-4.50
120	-5.50	-5.06	-4.75	-4.56	-4.50	-4.56	-4.75	-5.06	-5.50
125	-7.50	-6.94	-6.50	-6.19	-6.00	-5.94	-6.00	-6.19	-6.50
130	-9.50	-8.81	-8.25	-7.81	-7.50	-7.31	-7.25	-7.31	-7.50
135	-11.50	-10.69	-10.00	-9.44	-9.00	-8.69	-8.50	-8.44	-8.50
140	-13.50	-12.56	-11.75	-11.06	-10.50	-10.06	-9.75	-9.56	-9.50

This problem was also a feature of the DPCR4 IQI, although the penalty would have been considerably lower at £3.8m.

The practical effect of this problem is that the IQI values Ofgem's estimate above that of the company's, even if Ofgem turns out to be wrong. While it may not be possible to remove the problem altogether, Ofgem should minimise it by returning to the calibration used at DPCR4.

Ofgem has also stated that it wants to put more focus on the DNOs' own plans – an approach which would seem to make use of the IQI more challenging. Presumably Ofgem's forecasts will themselves mirror the choices a DNO has made (for example, as a result of the stakeholder consultation).

The IQI and capex rolling incentive provide symmetrical incentives. Given the inherent riskiness of cost benchmarking (and the risk involved in delivering further efficiency improvements), extending these approaches to some operating costs would seem to be appropriate.

Ofgem's comment that it may apply the results of the building blocks to other areas is strange because it must estimate the costs of such areas in order to develop allowances; in which case, it will have all the components necessary to include in the IQI – its forecasts, the DNOs' forecasts and an incentive rate.

Finally, we believe that it is essential that Ofgem produces the IQI calibration matrix as part of its policy paper on 15 December 2008. This paper should also provide the criteria to enable any future changes to the IQI calibration matrix during the Business Plan Review process in 2009.

Question 10: How might the IQI and capex rolling incentive be improved or what additional measures could supplement them?

Our response to this question is included in our answers to Q9 and Q11.

Question 11: Should we aim to equalise incentives on network investment and business costs and how could this be achieved?

We agree that price controls to date have provided DNOs with an incentive to maximise costs entering the RAV.

At DPCR4 we said to Ofgem that this was causing a major distortion to its benchmarking of controllable costs. We believe that our view has been entirely vindicated by the improvements in reporting we have seen driven by the introduction of the Regulatory Reporting Pack (RRP).

We would support an approach which equalised incentives across the main expenditure categories.

The key features of such an arrangement would be:

- Costs traditionally labelled as capex, opex and indirects would be subject to one overarching target
- A single incentive rate would be applied to these grouped costs
- The incentive would be symmetrical, meaning that a proportion of overspends would be recoverable, irrespective of the original cost type – this would help deal with the risk of inappropriate controllable cost allowance of the type we currently face in DPCR4.
- Costs subject to more complex revenue drivers would be treated separately, for example any volume-driven capex such as that concerned with the costs of connecting DG, undertaking NTR work etc)
- Costs will be added to the RAV as a proportion of the group costs, the proportion for each DNO being set in relation to its ability to maintain an appropriate level of gearing consistent with comfortably maintaining investment grade credit rating and its ability to pay dividends.

Question 12: Is the timetable realistic?

Broadly, yes.

We would ask Ofgem to be clearer on the joint working groups it intends to set up, as currently there are important areas of policy development where it is unclear how progress will be achieved. This is particularly true in the environmental area.

It would also be beneficial to publish a more detailed timetable as this would help the DNOs to prepare.

1. Delivery challenges (p4.11)

Ofgem is right to recognise the delivery challenges that DNOs will face in DPCR5.

Regulation has been good at reducing costs, particularly overheads, and extending the life of existing network assets. However, it has been less good at preparing for the time when change is required (for example, the move to more decentralised generation) and when the pent-up need for asset replacement/reinforcement must be addressed.

2. Use of revenue drivers (p4.17)

The use of revenue drivers could be appropriate for areas of great uncertainty, for example in respect of upstream investment to support DG connections. However, we do not agree that it is necessary to use such an approach for new demand connections, since the costs of these is largely covered by connection charges.

A. Financial issues

The impact of recent corporate transactions (5.11)

Ofgem has questioned whether recent premiums to RAV are evidence of an overall regulatory package that is too generous, or whether the winning bidders have overpaid.

It is clearly very important that Ofgem understands this issue in order to avoid an inappropriate response that could damage confidence in the sector.

We believe that these premiums can be explained by the following factors:

- The use of highly leveraged structures (in holding companies) to maximise the tax-shield benefits
- The use of high levels of index-linked debt to (inappropriately – see below) create short-term equity return benefits
- Over-optimistic assumptions about regulatory out-performance, which in turn may come from misplaced assumptions about the benefits of control
- A continuing belief among investors of a regulator/government guarantee (i.e. investors and their advisors believe that a financial structure acceptable to Ofgem will continue to be 'financed' by Ofgem in the future)

<u>UUE</u>

The sale of UUE needs to be understood.

Firstly, there is the question of what the premium actually was. United Utilities cited 45% but the acquirers, Colonial, referred to 32%.

The difference can be explained by the choice of enterprise value, with UU choosing a 'fair' value approach (to make the sale look good) and Colonial taking a more sensible approach and using the nominal value of debt included within the transaction. The UU approach overstates the value of the deal because the cash consideration would not have reflected the 'fair market price' of the debt, but rather its nominal value (because the cash consideration itself reflected the market price of UUE).

We believe that the 32% premium can be explained by approximately:

- 10% – non-core business and excluded revenue
- 9% – benefit of index-linked funding
- 13% – price control out-performance

However, we also believe that the acquirers have over-estimated price control out-performance because that is how winning bids are put together. The bidders may well have looked at the historical track of out-performance thinking that this could be continued indefinitely. However, as we note elsewhere in this response, the sources of material regulatory out-performance are becoming harder to find:

- Quality of service – customers seem happy with current levels
- Opex – further efficiencies are hard to find and expensive/risky to deliver
- Capex – the IQI constrains outperformance

<u>IRR of infrastructure funds</u>

Of course, if the regulatory package was actually too generous, we would find that infrastructure funds would be earning higher returns than Ofgem assumed in its DPCR4 cost of capital calculation. But, when we examine the performance of these funds, we find that their target IRR is not sufficiently high to justify the premiums to RAV seen.

<u>The index-linked debt problem</u>

There is a major problem with the use of index-linked debt that the regulatory framework needs to address.

With index-linked debt, cash interest is payable based on the coupon and index value of the debt, with coupons typically 2-3% lower than those for comparable straight debt instruments. There is clearly a cash-flow benefit to this (particularly in early years), but at redemption it is the indexed value that is paid, and not the original principle.

This means that a licensee with index-linked debt should retain the cash savings on interest payments in order to provide for the higher redemption cost. However, there is nothing in the current price control framework to ensure this, with the result that there is nothing to stop this money from being handed to shareholders as increased dividends.

The financial ring fence is designed to prevent a DNO from essentially paying dividends out of its capital. However, in this case, its purpose is being defeated.

The requirement to maintain investment grade credit rating ought to be a further check against a DNO paying dividend out of capital. However, this is not likely to be effective if redemption dates are many years (and price control periods) into the future; and, of course, the ‘experts’ get things wrong (as has been amply exemplified by the fact that the current sub-prime crisis has come as a surprise to them).

We strongly believe that, as a minimum, Ofgem should strengthen the financial ring fence to require DNOs to build up a fund to cover the redemption cost of embedded debt.

Question 1: Should Ofgem use its traditional approach to calculate the cost of capital or should other approaches be considered in order to provide the necessary incentives to invest?

The primary incentives to invest are a guaranteed recovery of efficiently incurred costs and an appropriate cost of capital.

<u>Risk</u>

We agree with Ofgem's statement that "conceptually, the appropriate cost of capital for a DNO depends on the overall balance of risks and rewards contained in the price control package". It means that the cost of capital is primarily driven by how the regulatory package deals with the underlying business risks. Therefore, it is possible to adjust the risk to revenues within the price control to determine the level of riskiness and thus determine an appropriate cost of capital.

For example, we foresee that the DPCR5 package could include new risks:

- Changes in government energy policy which subsidise DG/DE (such as feed-in tariffs)
- Building assets ahead of need, for example providing advanced infrastructure to facilitate future major new development which is described in RDA development plans
- The use of new technology which as yet has no proven track record of reliability (or longevity), for example technologies to develop more actively managed networks to facilitate the connection of DG
- New environmental incentives
- Funding of skills development
- Risks associated with an enlarged role (DNO agency, for example)
- Relative price effects (materials, contractors etc)

In the GDPCR Ofgem informed its cost of capital decision by assessing the relative riskiness of the GDNs against that of transmission, and Ofgem has said that it will carry out an exercise to compare the DNOs with the GDNs. Clearly, given the above statements, this should only be done once the DPCR5 framework has been established.

At times of rising levels of investment, the risk profile of a DNO will change. During such periods, project delivery/cost risk will be increasing in size relative to operating risk. Indeed, because operating risk tends to be quite stable over time, heightened levels of investment will increase overall levels of DNO risk.

Investment risks are largely systematic, for example the risk of cost overruns is systematic through the economy, as is the risk of increased input prices. Systematic risks cannot be diversified by shareholders and so will increase the cost of capital.

Ofgem correctly recognised the relationship between rising investment levels and the cost of capital in its DPCR4 final proposals paper, which said:

"Consistent with this focus on investment, the cost of capital falls within the upper half of the range presented in the March 2004 Policy Document"

We would expect Ofgem to take a similar view at DPCR5, especially if its approach to financeability/regulatory depreciation puts pressure on dividend flow (investors cannot rely on capital growth alone because regulatory risk cannot be eliminated – e.g. new taxes on utilities, changes to the regulatory contract as indicated by Ofgem's RPI at 20 project etc), or even requires the formation of new equity through rights issues.

There are additional tools at Ofgem's disposal which seek to either reduce risk or reward investment. Mechanisms to reduce risk, primarily cost-overrun risk, include pass-through mechanisms, volume drivers, building contingency into allowances, and a re-opener trigger mechanism. The main tool for rewarding investment is to allow higher returns for particular risks, for example the risk of delivering a large one-off project such as Heathrow Terminal 5.

We do not have any particular projects which could justify a bespoke rate of return.

An appropriate cost of capital is also one that would include a buffer to allow for the risk of unpredictable changes to underlying financial market trends within the control period.

EDF Energy Networks is prepared to consider increased levels of risk provided that appropriate rewards are achievable. We are therefore looking for incentive arrangements which have the effect of increasing returns on the RAV.

Cost of debt

It is perhaps too early to say how the credit crunch will impact on the cost of debt. Clearly, this will need to be kept under review right until the final proposals in later 2009.

Cost of equity

Ofgem intends to use its ‘aggregated return on equity’ approach because of the limited market data available on the DNOs, which implicitly assumes a beta of one. It also implicitly assumes that DNO gearing levels are at the market average.

Ofgem may want to raise assumed gearing levels for the DNOs, above the current 57.5%. If so, it needs to be remembered that the cost of equity is not independent of gearing (the well known analysis carried out by Modigliani and Miller in the late 1950s does not depend on the use of CAPM or any other modelling approach).

Gearing

If Ofgem retains its approach of using a notional balance sheet it will need to ensure consistency of assumptions between reviews. For example, if its DPCR4 modelling showed notional gearing rising across the period from 57.5% to, say, 62.5%, it cannot assume an opening DPCR5 gearing of 57.5%. There are two ways of addressing this:

- Reflecting this increased gearing in the cost of capital – by increasing the cost of equity; or
- Ensuring that a company had the same levels of gearing at the start and end of the period, if necessary by assuming a notional sale of equity (and due recompense for the cost of such sales).

Overall, Ofgem says that an efficient DNO should be able to earn the cost of capital. But, as the cost of capital is derived from averagely efficient companies, the cost of capital available to efficient DNOs should be somewhat higher.

Question 2: In particular, should measures to protect DNOs from debt market volatility be considered, such as indexation of the cost of debt, or the use of re-openers at “trigger” levels of interest rates?

The principal protection against such volatility is to encourage sensible levels of gearing and the formation of additional equity.

While it is theoretically possible to construct debt indexation or trigger mechanisms, the practical problems are formidable – in deciding what types/terms of debt to include in the index, for example. We do not, therefore, support the introduction of such mechanisms and we note that both the CC and CAA have recently come to the same conclusion.

We comment on the possible measures Ofgem could introduce below:

- Debt indexation – the BAA was right to point out that there is no good reference price for the cost of debt: choosing one is liable to create perverse incentives to match Ofgem choice rather then peruse the most efficient solution.

We also note that the CC also recommended an additional 15bps to cover debt commitment, agency and arrangement fees. However, as this amount was applied to all debt costs and not just new debt, it had the effect of providing a limited buffer against market volatility.

- Debt triggers
- Embedded debt – we support Ofgem's use of long run market indicators, which implicitly allows for the cost of some historic debt.
- Split rate of return – this is only sensible if DNOs have a limited number of very large projects with unusual risk profiles (we are not aware of any).
- Equity injections: we believe that assuming equity injections has merits provided that the cost of capital is right. We note that Ofgem believes that equity is interested in RAV growth – but of course, this means profitable RAV growth and not growth per se.

  We also believe that equity (and indeed the ratings agencies) will need a period of adjustment to any new arrangements since assumed rights issues have not been a feature of GB price controls before. In adopting this approach, Ofgem should make only cautious assumptions regarding the scale of any equity injections.

  Ofgem states that the "evidence clearly shows" that utility rights issues do not require a discount to the share price. However, the UU issues indicated a substantial cost.

The regulatory cost of capital, although based on historic market data, should nonetheless include an amount to reflect the risk of short-term volatility. Normally, regulators implicitly do this by selecting a cost of capital towards the upper end of the range of the modelled estimates. We see no reason for changing this practice, particularly as by the time the DPCR5 final proposals are being developed, the extent, impact and duration of recent turbulence should be clearer.

Question 3: Should Ofgem make financeability adjustments or is this a matter for DNOs once the cost of capital is set?

In theory, we do not think that financeability payments are valid provided that the cost of capital is set at a level that attracts equity formation. However, in practice, the markets are not used to UK regulators assuming high levels of retained earnings or even rights issues (as they are in the US, for example), which suggests that a more cautious approach is needed for DPCR5 – for example, one in which a blend of financeability adjustments and equity formation incentive are made.

Question 4: Is it appropriate for Ofgem to be making commitments on investment and its financeability over the longer term?

Yes.

At the moment, we are facing constraints in the market for the manufacture of distribution equipment in the face of a need not only to renew networks right across the developed world, but also to supply the growing networks in the emerging economies of Asia and South America.

It is becoming increasingly important for Ofgem to make commitments for future price controls because of the long-term nature of the issues the electricity distribution sector faces. For example:

- If Great Britain is unable to make commitments to manufacturers, and other countries are, this would lead to a loss of efficiency in procurement compared to those other countries
- the funding of skills development and recruitment
- the need for advance booking of factory capacity for major plant items
- technological change in response to increased amounts of distributed generation and possibly demand side participation (DSP)
- investment in research, development and deployment of new technologies

We have for some time been concerned by the relatively short-term approach Ofgem has been taking – an approach which has (with some notable but small scale exceptions) largely focused on the next price control period only. For this reason we (via the Government's Energy Policy Review) encouraged Ofgem to undertake a long-term modelling exercise so that it could gain a better understanding of the long-term issues facing the sector. Ofgem's LENS project could make a contribution towards this objective, although it will stop short of recommending network development strategies or new DNO business models.

Question 5: Should a mechanism for ex-post adjustments for major changes in the tax regime be introduced and, if so, how?

We are broadly in favour of a symmetrical mechanism for ex-post adjustments for major changes in the tax regime, as these are likely to be mostly beyond our control (i.e. such costs would be passed through to customers in a competitive market). However, a clear definition of 'major change' would need to be agreed with Ofgem – probably with reference to some materiality threshold.

Furthermore, there needs to be a clear distinction between the treatment of 'major changes to the tax regime' and tax efficiencies. The inappropriate capture of tax efficiencies would, of course, destroy incentives for efficient tax management.

Question 6: Do respondents support the publication of a fully populated financial model?

Yes, in principle.

Question 7: Should we calculate the DNOs' allowed revenues in a way that creates a smooth revenue profile over the course of the price control period and seek to reflect the level of costs expected in the last year of the control in order to reduce price changes from one control to another?

Yes; our revenue is equivalent to distribution prices, so having smooth revenue profile has benefits in avoiding large price shocks to customers.

We believe that DNO revenues should be smoothed

Electricity suppliers incorporate distribution charges into their products and find it difficult to deal with significant price changes.

We therefore not only support the smoothing of base price-controlled revenues, but also the use of rolling incentive mechanisms, which also has a dampening effect on volatility.

Question 8: What factors should we take into account when determining the level of gearing to assume?

We do not believe that it would be appropriate to make any significant changes to the level of notional gearing used at DPCR4. Although higher levels of gearing can reduce the WACC (via the tax shield), they also increase the risk of financial distress.

Our customers value having resilient energy infrastructures and we believe that this implicitly means resilience to both physical (engineering) and financial shocks, for example those which could arise from severe weather and terrorism.

We note that some utilities have been able to put in place very highly geared financing structures yet still obtain an investment grade credit rating at the licensee level. We do not regard such arrangements as enduring, as perhaps the difficulties faced by the BAA illustrate. We also do not believe that regulators should place such key matters of public interest effectively into the hands of the credit rating agencies, which have no remit to protect customers' interests or the public interest. We note that in the current credit crisis, the rating agencies were slow to identify the underlying risk of repackaged debt.

We note that other regulators share our view. The Civil Aviation Authority (CAA), in its recent price control determination for Heathrow and Gatwick, and endorsing the view taken by the Competition Commission, used 60% gearing as the right balance between efficiency and resilience.

Question 9: Do respondents agree with the proposed treatment of net debt and gearing in ex post adjustments to tax allowances?

We are keen to work with Ofgem to discuss the details and would encourage it to establish a tax managers working group.

One area we would like to have clarified is what Ofgem means when it says “we also intend eliminating the benefits of any group tax effects”. We presume this simply means putting the tax position of each DNO on to a stand alone, but we would welcome Ofgem’s confirmation of this.

Question 10: What are acceptable alternative approaches to calculating RAV additions; and, following recent market transactions, does RAV continue to reflect the underlying enterprise value of the business?

RAV represent the underlying business value of a price controlled entity; statutory accounts do not.

Since the RAV is merely a repository of unrecovered costs, we see no reason why it should have any bearing on the market price at which investors buy and sell a DNO’s shares. Recent transactions will reflect the motives of those involved, which have nothing to do with how costs enter the RAV.

Of course, there has long been a potential issue regarding the divergence between regulatory and statutory assumptions; nowhere is this more pronounced than regulatory depreciation whereby price controls assume 20 years, whereas statutory accounts have asset lives of 60 plus years. At some point this could cause a write down in statutory accounts.

We believe that it is important that Ofgem continues to incentivise DNOs to strive for future efficiencies in their business. As recognised by Ofgem, we have reached the point of diminishing returns for these future efficiency programmes. We therefore feel it is appropriate for Ofgem to consider allowing non-operational capex to be allowed as part of the RAV.

Process and timetable

Question 1: Do you agree with the range of consultation approaches we intend to use throughout DPCR5?

Yes, on the basis that there is a 'September update', or equivalent communication, to the DNOs.

Question 2: Do you believe that we should utilise a consumer orientated challenge group to inform DPCR5?

No, because the views of this group are unlikely to be representative of consumers generally. Considerable effort is needed, as Ofgem knows, in its willingness to pay work in order to achieve a robust outcome. The creation of a challenge group seems to undermine this.

Question 4: Are there any other ways in which we should look to consult with interested parties?

No.

Question 5: Do you agree with our approach to publish specific impact assessments for key "important" decisions?

Yes.

Question 6: Are there any other key milestones that you believe we should consider for DPCR5?

The high level milestones are appropriate but further clarity is needed on lower level activity.

EDF Energy, June 2008