Rachel Fletcher
Partner Local Grids and RPI-X@20
Ofgem
9 Milbank
London
SW1P 3GE

19 October 2009

Dear Rachel

September Update to Initial Proposals

Thank you for the opportunity to comment on the proposals set out in your letter of 21 September 2009. I can confirm that this response can be placed on Ofgem's website.

Our detailed response is set out in the attachment to this letter. However, the key points I would like to draw your attention to are:

Demand Connections

- Our connections forecast is built on robust macro-economic analysis – Ofgem are wrong to replace this with a simple run-rate based on DPCR4 activity levels
- Shared user demand connection unit costs will legitimately vary depending on connection change policy and the loading of the existing network and Ofgem need to take this into account in its analysis

HILP, CNI and Black Start

- We will not incur significant expenditure on HILP without explicit ex ante confirmation from Ofgem that the expenditure is in principle efficient
- Ofgem's proposals to only allow 95% of HILP, CNI and black start costs to be logged up has no incentive properties (as efficient costs would be disallowed) and needs to be rethought.

Rising and Lateral Mains

- We agree that the high level of uncertainty in this area suggests that a re-opener mechanism is the most appropriate way of funding this area. However, Ofgem's proposal is not entirely clear. In particular, it could be read that any re-openers would not be available until April 2012 at the earliest and

that any costs incurred in the first two years of the control above those initial allowances (which are zero in the case of EDF Energy) could not be included. It would be iniquitous for Ofgem to deny funding of the EDF Energy cases currently in the course of being determined by Ofgem. We would not regard such an approach as a sensible way of dealing with this risk and we do not believe that this is what Ofgem has in mind

- We do not believe it is practicable for DNOs to be obliged to endeavour to resolve ownership with the first two years of the DPCR5 period

BT21CN

- Ofgem's proposal to defer EDF Energy's (and other DNOs) BT21CN investment proposals by one year, purely on the basis of a resubmission by SP (whose original forecast was in any case acknowledged as front-loaded), is unjustified.

Low Loss Transformers

- Ofgem should increase our capex allowances of £12m in respect of the additional cost of low-loss transformers we routinely use

Traffic Management Act

- All permit schemes which will be legally in force at the time of the Final proposals should be included in ex ante allowances where there is sufficient information available

If you have any questions about this response, please do not hesitate to give me a call.

Yours sincerely

Paul Delamare
DPCR5 Programme Director
EDF Energy

EDF Energy's Detailed Response

1. Customer specific demand connections

Summary

Ofgem's September proposals effectively set out Ofgem's initial review of DNOs FBPQ submissions as they relate to Demand Connections; specifically LR1 & LR1a tables.

TABLE 1 – Demand Connections

	£M				
	DPCR4 Act	DPCR5 Forcast	OFGEM Adj	CHANGE	Reduction (%)
CN West	56.1	26.2	20.8	- 5.4	-21%
CN East	89.4	66.6	62.3	- 4.3	-6%
ENW	72.9	24.4	8.8	- 15.6	-64%
CE NEDL	11.0	20.0	11.0	- 9.0	-45%
CE YEDL	9.8	28.6	14.2	- 14.4	-50%
WPD S Wales	6.0	5.4	5.4	-	0%
WPD S West	10.7	7.8	7.7	- 0.1	-1%
EDFE LPN	3.4	11.0	10.5	- 0.5	-5%
EDFE SPN	22.3	48.8	42.3	- 6.5	-13%
EDFE EPN	25.4	29.1	16.8	- 12.3	-42%
SP Distribution	22.0	16.4	16.4	-	0%
SP Manweb	36.0	40.5	40.5	-	0%
SSE Hydro	16.5	16.7	16.2	- 0.5	-3%
SSE Southern	24.7	58.8	56.9	- 1.9	-3%
	406.2	400.3	329.8	- 70.5	-18%

Ofgem adjusted total (referred to as Sept Update Baseline) in the September document is an amalgam of adjustment made to shared connections schemes subdivided into two categories; these are **Low Volume High Cost (LVHC)** connections and **High Volume Low Costs (HVLC)** connections. Of the £19.3m reduction from EDF Energy FBPQs shown in table 1 above, £18.1m relates to Low Volume High Cost (LVHC) connections.

EDF Energy has three concerns with regards to the methodology used by Ofgem to formulate the proposed reductions in allowed connections shared use revenue for DPCR5:

- The different application of connection charge methodologies across DNOs impacts the proportion of funding between general customers and connection customers. It is therefore flawed to imply a relative "efficiency" of DNOs from net connection charge costs alone;
- There are a number of network specific issues impacting on the proportion of customer to DNO funded costs that Ofgem have not taken into account.

Specifically the relative utilisation of Networks will vary the proportion of reinforcement required to facilitate connections over time.

- Ofgem have not taken into account the underlying regional specific factors (both in terms of the general level of economic activity and regional costs) that will impact on future connections activity.

This response provides a detailed explanation of the impact of these issues on Ofgem's cost assessment methodology for connections.

Low Volume High Cost (LVHC)

These schemes are defined as a Shared Connections Schemes (subject to the Apportionment Rule) which are HV and above (but exclude LV involving HV schemes). The methodology employed by Ofgem to determine the adjusted baseline position was as follows:

- Reference to DPCR4 expenditure
- Reference to Ofgem question NI 5062 (Major Scheme's requiring upstream reinforcement).

TABLE 2 – Low Volume High Costs (LVHC)

	£M				
	DPCR4 Act	DPCR5 Forcast	OFGEM Adj	CHANGE	Reduction (%)
CN West	21.2	12.6	12.6	-	0%
CN East	52.4	49.9	45.9	- 4.0	-8%
ENW	35.8	6.3	6.3	-	0%
CE NEDL	2.6	9.2	5.3	- 3.9	-42%
CE YEDL	2.7	14.3	5.6	- 8.7	-61%
WPD S Wales	3.6	3.0	3.0	-	0%
WPD S West	8.0	5.4	5.4	-	0%
EDFE LPN	3.1	8.5	8.5	-	0%
EDFE SPN	13.7	41.4	35.6	- 5.8	-14%
EDFE EPN	12.3	24.6	12.3	- 12.3	-50%
SP Distribution	1.3	11.1	11.1	-	0%
SP Manweb	16.9	36.4	36.4	-	0%
SSE Hydro	12.6	10.5	10.1	- 0.4	-4%
SSE Southern	15.1	42.6	40.7	- 1.9	-4%
	201.3	275.8	238.8	- 37.0	-13%

Table 2 shows the Ofgem adjusted total expenditure for DPCR5 from £275.8m to £238.8m across all Licence areas. EDF Energy accounts for almost half of this reduction with EPN bearing £12.3m of the total.

Methodology Concerns

As discussed in the response to Ofgem question NI 5062, the named schemes detailed in the Asset Plan merely provide a starting point for estimating future Capex requirements. In the EPN area, at the time of the LR1 compilation only one scheme was formally registered within our asset Plan. This identified only £1.6m of funding in the DPCR5 period.

The forecasting methodology adopted utilises other drivers in determining growth forecasts including publically available macro economic data. As discussed in the formal response, Oxera employment forecasts have been adopted as the growth driver specific to each of the EDF Energy regions as this measure demonstrates correlation to DNO investment expenditure in major schemes.

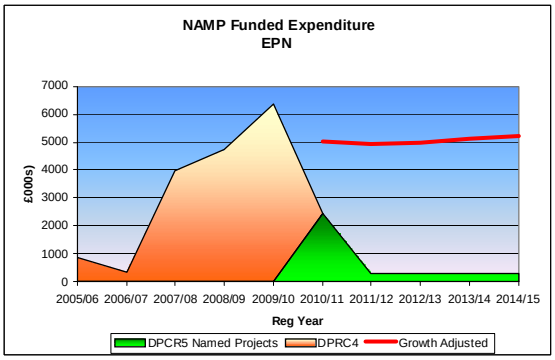
The growth forecasts indicate average expenditure levels in line with 2009/10 of circa £5.5m per annum. EDF Energy's forecast for DPCR5 is consistent with this higher level of connections activity; which Ofgem has not taken account of.

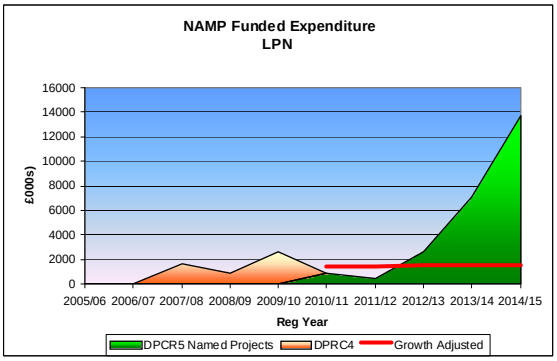
EDF Energy's FBPQ projected an average unit cost in DPCR5 of £500k for EPN. Ofgem's September proposals imply a reduced unit cost of £380k, with no explanation to why these costs have been disallowed.

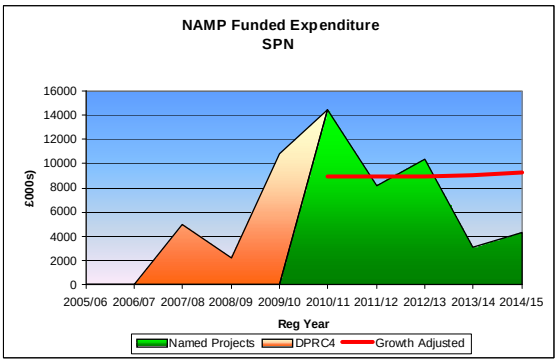
Ofgem appear to only endorse our forecast expenditure where the value of named schemes exceeds the forecasts (i.e. LPN - see NAMP funded Expenditure graph). Where this is not the case, Ofgem appear to have applied a simple expenditure "run-rate" based on DPCR4 data. This simplistic approach undermines the forecasting process in that it takes no account of the impact of the macro-economic factors which drive connections activity. The use of simple historic run rates ignores the status and the availability of capacity of our networks or the reinforcement expenditure required.

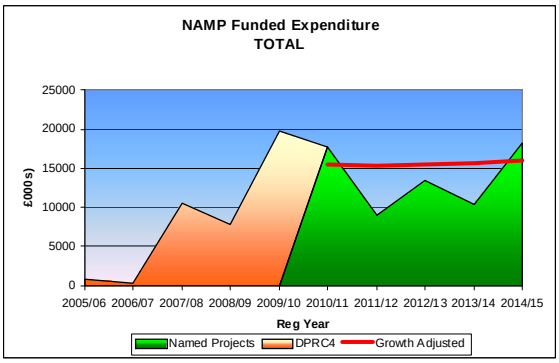
The forecasting approach is both legitimate and consistent across our three DNOs. The overall EDF Energy picture depicts a prudent and justifiable level of investment expenditure across the DPCR5 period.

We understand that there is a mismatch between our individual DNO schemes and the respective DNO specific forecasts. However, taken as a whole, there is a good fit across EDF Energy's area. The charts below demonstrate the position:









High Volume Low cost connections.

TABLE 3 – High Volume Low Costs (HVLC)

LV with LV Only	DNO SUBMISSION					OFGEM ADJUSTMENT			
Units	Units	Gross Unit Cost	Net Unit Cost (DNO Funded)	Net %age	CAPEX £m	Benchmark Gross Unit Cost	Net %age DNO funding	DPCR Baseline CAPEX £m	Change
EDFE LPN	820	2,440	610	25%	0.5	1,723	25%	0.4	-0.1
EDFE SPN	4713	2,037	530	26%	2.5	1,723	26%	2.1	-0.4
EDFE EPN	3279	1,677	457	27%	1.5	1,677	27%	1.5	0.0
					4.5			4.0	- 0.5

LV with HV	DNO SUBMISSION					OFGEM ADJUSTMENT			
Units	Units	Gross Unit Cost	Net Unit Cost (DNO Funded)	Net %age	CAPEX £m	Benchmark Gross Unit Cost	Net %age DNO funding	DPCR Baseline CAPEX £m	Change
EDFE LPN	738	6,100	2,711	44%	2.0	5,058	44%	1.7	-0.3
EDFE SPN	2357	5,389	2,079	39%	4.9	5,058	39%	4.6	-0.3
EDFE EPN	1947	3,596	1,541	43%	3.0	3,596	43%	3.0	0.0
					9.9			9.3	- 0.6
					14.4			13.2	- 1.2

The table above shows the £1.2m adjustment to the originally submitted Capex forecast.

LV with LV Only

The methodology employed by Ofgem was as follows:

- Determine the gross benchmark unit cost by calculating the median gross unit cost from all DNO returns
- Apply the benchmarked costs to DNOs, who average unit cost is greater than the benchmark, (those below the benchmark will have their average).
- Apply the net percentage (i.e. the percentage of DNO funding for a shared LV with LV schemes) to the benchmarked gross cost
- Multiply this total the forecasted units to determine the allowable baseline capex

Methodology Concerns

The concerns with the approach adopted are as follows:

- Using the gross cost (which is the total of sole use, customer funded shared use and DNO funded shared use) as the basis for the calculation masks the aspect of the unit cost which Ofgem are specifically seeking to target and control i.e. the shared use element

  Whist all DNOs are at high level operating to the same 'shallowish' connection charge methodology, DNOs apply the current rules in a manner that materially varies the customer's connection charge. For example, the value being entered as the denominator in the 'security cost apportionment factor' as 'new network capacity' can be materially impacted by the interpretation applied regarding the seasonal ratings of plant and the section of network to be considered within the calculation. A DNO which seeks to apply the connections charging methodology in the manner in which it was designed (i.e. the connecting customer pays for investment directly driven from his connection as opposed to this being funded by the wider community via use of system charges) is penalised. Those DNOs will have a proportionately lower net DNO funding percentage and will therefore attract a reduced baseline allowance. (See worked example 1)

Example 1

	Unit Cost (£)						
	Customer Funded Sole	Customer Funded Shared	DNO Funded Shared	Gross Cost	Net %age	No of Units	Allowance (£)
DNO A	500	300	300	**1,100**	27%	800	240,000
DNO B	500	100	500	**1,100**	45%	800	400,000

The example 1 on the previous page demonstrates that different interpretation of the charging methodology between two DNOs may result in a higher level of DNO funding which is rewarded by a high allowance

- Conversely, those DNOs who interpret the charging methodology in a manner where the connecting customer initially pays less (and therefore the wider community through DUoS pays more) will continue to attract higher baseline allowances
- The inclusion of the sole element detracts from the analysis of the funding of shared schemes and how the charging policy is being applied. If the sole use element is significantly lower in one DNO this may have a distorting affect by lowering the benchmarked unit cost; (see worked example 2)

Example 2

	Unit Cost (£)						
	Customer Funded Sole	Customer Funded Shared	DNO Funded Shared	Gross Cost	Net %age	No of Units	Allowance (£)
DNO A	500	300	300	**1,100**	27%	800	240,000
DNO B (equal to Median)	300	300	300	**900**	33%	800	240,000
DNO A (Adjusted)	300	300	300	**900**	27%	800	194,400

In example 2 the shared cost of the scheme is exactly the same for both DNOs however, because DNO **B** has a cheaper sole use element (which is irrelevant to the allowance calculation); its gross cost is lower. DNO B's gross cost pushes down the median for the industry. This has a compounding affect on DNO A in that its net percentage appears to be lower than DNO B therefore will receive a reduced allowance and its base line cost may be adjusted down to the benchmarked cost purely due the sole use element. Therefore DNO A will receive a reduced allowance of £45.6k despite the shared element of the scheme being exactly the same.

- The use of the median gross cost is at best arbitrary in that it ignores regional differences

- The funding of relatively low cost small scale domestic and one-off connections via use of system charges is promoted by this mechanism as these schemes attract a capex allowances. EDF Energy finds it difficult to understand the gross unit costs within this category. For example, CN West £7,447 gross unit cost for a small scale LV domestic / one off commercial scheme would mean a total gross cost approaching £8,500 after attributable overheads are applied. The average customer connections charge would be over £5,600 for an LV connection, in EDF Energy the typical customer pays nothing

LV with HV

The methodology employed by Ofgem was as follows:

- Determine the gross benchmark unit cost by calculating the upper quartile gross unit cost from all DNO returns
- Apply the benchmarked costs to DNOs, who average unit cost is greater than the benchmark, (those below the benchmark will have their average).
- Apply the net percentage (i.e. the percentage funding for a shared LV with HV schemes) to the benchmarked gross cost
- Multiply this total to the forecasted units to determine the allowable baseline capex

The concerns with the approach adopted are as follows:

- Unlike "LV with LV" works, this activity is not homogenous in nature. The variability of projects at this voltage level invalidates the use of a blanket industry wide unit cost. The level of reinforcement is highly dependent on the point of connection and the capacity availability within the network
- The use of the gross costs as a basis for comparison is questionable (as discussed above)
- The use of the upper quartile to benchmark is at best arbitrary and ignores the status and capacity available on the network

2. Funding approach (CNI, black start and HILP)

Ofgem proposes that DPCR5 costs can be recovered (p1.25/p1.35)

- Directly from individual customers
- In DPCR6 via a logging up mechanism (95% of cost only)
- In DPCR5 if a combined (with CNI and black start) threshold is exceeded

We agree that the uncertainty surrounding these costs suggests that setting an ex ante allowance is impractical at this stage. However, it is difficult for us to support Ofgem's proposed use of a logging up mechanism without understanding the intended materiality threshold. We believe that in the interests of fairness the threshold should be common across the DNOs and be set at around half the average forecast spend – i.e. the threshold should be set at £5m. Given that our DPCR5 LPN HILP investment alone is anticipated to exceed £50m we would expect all of these costs to be subject to a re-opener once the required level of investment to be funded by EDF Energy (i.e. net of any possible contributions) is clarified.

In addition to the value of the re-opener issue, the other key issue we have with Ofgem's proposals is one of certainty.

Before we commit significant amounts of money in these areas we will need assurance from Ofgem that the proposals will be regarded, in principle, as efficient. This is particularly relevant to HILP where the question of efficiency could well reach into the domain of whether the investment was considered necessary at all.

We do not understand Ofgem's proposal to only allow only 95% of the costs to be logged up to "encourage efficiency". This is nonsensical as it would deny recovery of cost whether they were efficient or not. The proposal should be withdrawn.

Lastly, we do not think it likely, as Ofgem suggests that HILP costs will be recovered from individual customers. While we are actively supporting on-going discussions between Ofgem, DECC and City of London Corporation, two things have become particularly clear during the course of those discussions to date:

- City of London Corporation are very supportive of our HILP proposals and believe that the works are essential to retaining the confidence of the Financial Services Sector in maintaining a strong base in the City; and
- City of London Corporation has a concern that should the sector be asked to contribute to the HILP works, that in itself might undermine confidence as to whether the resilience of the electricity network to a 'low probability' (but nevertheless entirely credible) event is sufficient for them to continue to base their operations in the City

The majority of the proposed HILP costs will apply to EHV assets used by all connected customers attached to the relevant lower voltage circuits. In this respect the nature of the investment is no different in principle to the bulk of the general reinforcement works we propose under our City and West End Regional Development Plans. Ofgem does not dispute the principle that our investment in these works (including the 'high value' projects) should be recovered through the normal RAV mechanism and we see no rationale for treating the HILP investment works

differently. In any case, as we have previously discussed with Ofgem, it would not be practicable to charge all those customers individually (either through some form of connection charge or through a geographically specific DUoS price).

3. Black start and Emergency Batteries

Our investment to provide the necessary Black Start capability can be finalised only once the Energy Emergencies Executive Committee (E3C) has specified the required level of resilience (in terms of battery capacity and/or standby generation capacity) to be provided. This specification is anticipated early in 2010. We agree that at this stage it is not practicable to determine an ex-ante allowance but if, as we anticipate, the required level of investment will be substantially more than £5m per DNO, we would expect an allowance to be set through a specific 're-opener' provision, rather than applying a logging up approach.

4. High Impact Low Probability risks

As we comment above, we are continuing to support ongoing discussions between Ofgem, DECC and City of Corporation of London and have provided a full report and supporting presentation material to facilitate these discussions. City of London Corporation has made its position very clear (as outlined above) and both DECC and Ofgem have been asked to reconsider their positions regarding funding mechanisms and report back at the next meeting which is planned for 6 November (no earlier date mutually convenient to both Ofgem and DECC being available).

5. Rising and Lateral Mains

Funding approach

We agree that the high level of uncertainty in this area suggests that a re-opener mechanism is the most appropriate way of funding this area. However, Ofgem's proposal is not entirely clear.

In particular, it could be read that any re-openers would not be available until April 2012 at the earliest and that any costs incurred in the first two years of the control above those initial allowances (which are zero in the case of EDF Energy) could not be included. It would be iniquitous for Ofgem to deny funding of the EDF Energy cases currently in the course of being determined by Ofgem. We would not regard such an approach as a sensible way of dealing with this risk we do not believe that this is what Ofgem has in mind.

We ask Ofgem to confirm that the R&L re-opener mechanisms will encompass all relevant costs incurred in the DPCR5 period.

Establishing ownership

We do not believe it is practicable for DNOs to be obliged to endeavour to resolve ownership with the first two years of the DPCR5 period.

There are many thousands of R&L systems within our DNOs area (mostly in LPN) and each case would have to be determined on the evidence of ownership available. Ofgem is already familiar with the complexity of the issues arising from the current determination cases before it and should realise the impracticality of repeating that process hundreds, if not thousands, of times over within a two year window.

Inspections and maintenance costs

We are concerned that these costs will be assessed using regression models which do not have the number of R&L systems as a driver.

The number of R&L systems we inspect is set out below:

	No of R&L systems
EPN	205,393
LPN	282,544
SPN	177,655

Since R&Ls systems are essential an urban issue it would be unfair to benchmark these costs against DNOs which do not incur them. This strongly suggests that R&L inspection costs be treated as an additional urbanity factor and excluded from the benchmarking.

6. BT21CN

We find Ofgem's proposal to defer EDF Energy's (and other DNOs') BT21CN investment proposals by one year, purely on the basis of a resubmission by Scottish Power (whose original forecast was in any case acknowledged as front-loaded), a purely arbitrary decision. Notwithstanding BT's 'August' update, there remains considerable uncertainty over BT's commitments even before (and certainly after) 2018. EDF Energy's forecast is not front-loaded; it is optimised in terms both of scope and timing and Ofgem's assumption that the overall investment programme can simply be moved back by one year is clearly lacking any objective rigour.

For the sake of what would amount to a minimal npv benefit for customers, the effect of deferring our programme by one year would considerably increase the risk of a scenario wherein EDF Energy had been unable to make adequate provision for its major inter-tripping circuits.

7. Flooding

We are please that Ofgem has accepted our proposals in full.

8. Technical losses

We have explained at some length in (and since) our FBPQ submission that we have explored the economic viability of procuring (even) lower loss transformers and installing (even) larger cross-section LV cables, but that our investigations have revealed that our current specifications and network designs are already the lowest loss options that can be economically justified. We nevertheless indicated that we would welcome an initiative to establish a benchmark position for equipment efficiency among the DNOs. To do this it would be necessary to understand the efficiency of plant, especially transformers, currently purchased by DNOs in order to establish an efficient 'base case'.

This suggestion was not followed up by Ofgem, yet we note that four companies, CN, ENW, SP and SSE, have been granted allowances for additional investment to reduce technical losses. We also note that no 'unit-cost' adjustments have been made to EDF Energy's capex allowances to reflect the fact that we are already pursuing low loss options.

It would clearly be illogical for some companies to be granted additional allowances (for example to bridge the gap between their and EDF Energy's specifications) without also granting EDF Energy an appropriate allowance to continue with our current policy.

We described in our NL11 submission, and the accompanying narrative, the level of losses we believe our current policy will save over the DPCR5 period. Across our three licensed areas we estimated that this saving would amount to 36,159MWh.

Taking table 11 of the September update we note that Ofgem propose to allow £15.6m of incremental expenditure across seven licensed areas to save 45,936MWh of losses in total. It follows that on a pro-rata basis, a £12.3m overall positive adjustment should be made to our DPCR5 capex allowances to maintain equity with the enhanced allowances granted to the above companies in terms of the losses benefit derived. We believe this figure is consistent with the premium we are currently paying for pursuing low loss plant specifications and network design options.

9. Discretionary expenditure

We were disappointed by Ofgem's disallowance of EDF Energy's discretionary investment proposals which we feel had considerable merit in terms of supporting field trials of active (or smart grid) technologies that will need to be further developed and in future selectively deployed to allow distribution networks to support the UK Low Carbon Transition Plan and Renewable Energy Strategy. Indeed we felt that our proposals were considerably more in the spirit of cost-effectively advancing relevant network technologies than some other discretionary proposals we had noted.

However, we do acknowledge that our proposals would be well suited to funding through the proposed Low Carbon Network Fund. Whilst this mechanism will result in less than 100% ex ante funding of the proposed investment, we would support that approach provided it is universally applied to all DNOs' discretionary proposals and based on the merit of those proposals in terms of their potential (above and beyond that which will in any case accrue from a mandated smart metering programme) to enhance the capability of networks to support a low carbon energy strategy.

10. Traffic Management Act (TMA)

EDF Energy recognises that there has been benefit in Ofgem attempting to achieve consistency between the DNOs' TMA submissions. However, given the unique conditions within each DNOs operating area and the different ways that noticing schemes are implemented across the country, we do not believe it will be possible to fully normalise these submissions.

EDF Energy continues to be disappointed with Ofgem's decision to include permitting costs and additional expenditure from the London Code of Practice under a reopener and not within the ex-ante allowance. As stated in our response to the August Initial Proposals Paper, we will start to incur permitting related costs from January 2010 onwards. Kent County Council has already had a permit scheme approved by the Secretary of State and additionally, the permit schemes are likely to be in place within 18 London Boroughs from early 2010 onwards. Therefore, at the start of DPCR5 a significant proportion of EDF Energy's network (approximately 30% of our customers) will be covered by active permit schemes and the remainder of our network will be subject to permit schemes by 2011. Consequently, unlike the remainder of the DNOs we will be bearing significant costs in the early years of DPCR5 until the reopener mechanism becomes active.

We also believe there are a number of issues with Ofgem's proposed approach to the reopener mechanism. Ofgem's position is that the reopener will not take into account increases in work volumes. Our concern is that Ofgem are setting the

baseline volumes for notices (and hence work volumes) but we will be exposed to the full impact of any error in this forecast. This is unacceptable. Given that Ofgem have, in general, agreed with our work volumes we would expect our forecast of works to be used in the derivation of the base allowances.

We understand Ofgem's desire to have a mechanistic approach to setting TMA. However, the approach cannot be wholly mechanistic, as operating environment factors will differ across DNOs. For example, the percentage of traffic sensitive streets in the LPN area is twice that of either our EPN or SPN area. A simple comparison of permit scheme costs per job would not reveal these differences. It is therefore important that the information template to support the reopener is sufficiently detailed to capture these relevant differences and these factors are considered when Ofgem determines the level of efficient costs.

The proposal for the reopener application window is unclear. The current proposal could be interpreted as either the window closes in March 2012 or opens in March 2012. If it is the latter there is no indication of how long the window would be open for. It is also unclear why 12 months of cost data is required when the equivalent reopener in the GDPCR requires six months of cost data. If the requirement for actual cost data is aligned with the gas regime then submitting a reopener application by March 2012 is practicable. If 12 months of cost data is required then the application window should be kept open until March 2013.

Lastly, we wish to comment on the approach taken for excluding the TMA administration costs and calculating the proportion of capex load related TMA costs which are outside the price control. Ofgem has moved the TMA administration costs under the Group 2 indirect costs. The robustness of this approach is debatable. At Initial Proposals, the cost driver for this analysis was Modern Equivalent Asset Value (MEAV). However, Ofgem's own statistical analysis demonstrated that this model was mis-specified. The addition of TMA administration costs, which are driven by work volume not asst values, is likely to further increase this mis-specification. We understand that the driver has now been revised to include direct costs. This should ameliorate this issue; however, it is vital that the weights are appropriately set on each element of the driver.

Ofgem's current TMA model includes permit, notification and inspection penalties, as well as overstays fines, when calculating the costs which are attributable to sole use assets. We do not think this approach is appropriate since connection charges are entitled to include only *reasonable* expenses which are incurred in providing lines and plant to be defrayed by the person requiring connection (see Section 19 of the Electricity Act), has recognised that it would be prohibitively expensive for an efficient DNO to have no failures. Given that the customer is not responsible for the

failure we can see no justification for including these costs in connection charges, as any future connected customers will effectively pay twice, once in its connection charge and once in its ongoing use of system charge. We believe that these charges should be wholly funded through use of system charges.

11. Transmission Exit Charges

While we remain unconvinced of the need for Ofgem to create an incentive on exit charges, we are confident that EDF Energy's requests to NGET for additional transmission capacity will pass any reasonable test of need. As should now be apparent to Ofgem through its own modelling and in particular, our submitted output measures, EDF Energy's 132kV and EHV networks are very highly utilised. Our 'LI' output measures illustrate that load related reinforcements are executed only when an unacceptable risk of security falling outside of ER P2/6 recommended levels of system security is identified.

EDF Energy's policy is to seek the viability of additional NGET transmission capacity (including new exit points) only where it is apparent from our studies that it is unlikely that such capacity could be economically sourced from our existing 132kV and/or EHV networks. Options for additional NGET capacity vis-à-vis potential distribution network reinforcements are carefully explored through regular Joint Planning Liaison meetings with NGET. While greater transparency of NGET's capital costs (which are visible to Ofgem but less so to DNOs) would help ensure that the least overall (npv) cost and/or highest incremental benefit / cost solution is adopted on all occasions, we have no reason to believe that at any time a less than optimal solution has been adopted by EDF Energy.

The table published on page 93 of Ofgem's Initial Proposal document 94/09 includes a number of discrepancies from EDF Energy's final submission and answers to Ofgem's supplementary questions:

- The figures do not take account of our 15 July update paper
- The figures quoted for incentivised costs for SPN match neither those submitted by EDF Energy Networks in June or in our 15 July Update
- The figures include the assumption that all of the costs of schemes already committed to by EDF Energy Networks, where National Grid have placed contracts and construction works are underway are fully controllable by EDF Energy Networks[1]

[1] The figures from other DNOs, particularly for the early yeas of the DPCR suggest that either there is no-reinforcement work under way elsewhere in the country or other DNO's figures are on a different basis.

We have not seen any confirmation from Ofgem that they have recognised these errors and have therefore included our answers again for clarity.

EDF Energy Networks (EPN)

The list in the Initial Proposals s comprised of the following schemes identified in EDF Energy Network' June FBPQ Initial Submission: Bramford, Norwich, Tilbury and Wymondly. Of these four only the costs at Wymondly remain in negotiation. Of the remaining three:

- Bramford was committed to in 2006, and the project is under construction with the first phase nearing completion. The structure of the scheme is a result of National Grid's inability to deliver to their original commitment but our ability to influence the costs at this time is minimal because contacts have been placed and the termination costs would be similar to, or higher than, the completion costs
- Norwich was committed to in 2007, and the project is under construction with the first phase nearing completion. Our ability to influence the costs at this time is minimal because contacts have been placed and the termination costs would be similar to, or higher than, the completion costs
- Tilbury was identified in our submission of 15 July as replacement rather then reinforcement – there is no increase in capacity taking place

Removing Bramford, Norwich and Tilbury from the list results in more realistic view of the costs that EDF Energy Networks may have influence over and could be incentivised on:

£m	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Exit Charges	0.0	1.1	1.1	1.1	1.1	4.4

EDF Energy Networks (LPN)

Ofgem's Initial Proposals include the following schemes identified in EDF Energy Network' June FBPQ Initial Submission: Barking West, Barking C, Hackney, New Cross, West Ham and Willesden. Of these six; only New Cross, West Ham and Willesden are still being discussed with National Grid:

- Barking West was identified in June FBPQ submission of 15 July as National Grid initiated and was committed to in 2009.
- Barking C was identified in our submission of 15 July as refurbishment rather then reinforcement – there is no increase in capacity taking place.

- The new GSP at Hackney is being built for the Olympics. This scheme was committed to in 2006, and the project is under construction and nearing completion. Our ability to influence the costs at this time is minimal because contacts have been placed and the termination costs would be similar to, or higher than, the completion costs.

Removing Barking C and Hackney from the list results in more realistic view of the costs that EDF Energy Networks may have influence over and could be incentivised on:

£m	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Exit Charges	0.0	0.0	0.9	1.2	3.9	6.0

EDF Energy Networks (SPN)

The set of figures contained in Ofgems Initial Proposals does not match those submitted by EDF Energy Network either in June or in the 15 July Update. The forecast supplied in June was:

£m	2010/11	2011/12	2012/13	2013/14	2014/15	Total
3rd August IPs	0	0	0	3.8	4.3	8.1

This list is comprised of the following schemes identified in EDF Energy Network' June FBPQ Initial Submission: Bolney, Canterbury, Hurst and Kemsley. Of these four; Bolney, Canterbury and Kemsley are still being discussed with National Grid.

- Hurst was identified in our submission of 15 July, requesting that this scheme be removed from the list of proposed schemes because of changes to the design strategy.

Removing Hurst from the list results in a more realistic view of the costs that EDF Energy Networks may have influence over and could be incentivised on:

£m	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Exit Charges	0.0	0.0	0.0	3.1	3.1	6.2

12. Bad debts

We have already provided confirmation to Ofgem of the cost incurred

Paul Delamare
DPCR5 Programme Director