Northern Ireland Electricity Limited

Transmission and Distribution RP5 Price Control

Response to the Utility Regulator's Draft Determination

APPENDICES

19 July 2012

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1 Introduction

1.1 Background

As part of their preparation for RP5, NIE commissioned Frontier Economics to provide it with an independent assessment of its operating efficiency. Frontier's work was summarised in a report[1] submitted to the Utility Regulator as part of NIE's Business Plan Questionnaire submission. Frontier's conclusion was that NIE's present level of performance was consistent with the leading GB DNOs and that NIE should be regarded as efficient.

Working on behalf of the Utility Regulator, CEPA undertook a review of our work during the spring of 2011. Frontier provided CEPA with complete and open access to all our calculations to facilitate this review. As a consequence of a full audit of our work, undertaken to facilitate CEPA's understanding of our work, we identified a number of changes that should be made to our original analysis. A revised report[2] was prepared in May 2011 setting this out. Importantly, although a number of changes had been made to the analysis, our conclusion remained unchanged, i.e. that NIE's performance was consistent with the leading GB DNOs.

In April 2012 the Utility Regulator published its Draft Determination, including an appendix prepared by CEPA,[3] which summarised their analysis of the operating efficiency of NIE. In many regards CEPA followed a similar approach to Frontier. However, there were a range of important differences in approach and as a consequence CEPA identified a gap between NIE's costs and their assessment of efficient costs.

Based on the CEPA report, the Utility Regulator has indicated that it proposes to apply an "efficiency factor" of 9% in deriving "adjusted controllable opex" from a "controllable opex baseline". Its decision regarding an efficiency factor is one of many that underlie the Utility Regulator's assessment of opex. Absent any assessment of whether the CEPA approach and results are reasonable, the overall effect of all of these decisions taken by the Utility Regulator needs to be considered in assessing whether, ultimately, the proposals for controllable operational expenditures set out in the Draft Determination are reasonable or otherwise.

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1 Frontier Economics, "Econometric efficiency analysis of NIE's indirect costs and R&M costs", February 2011

2 Frontier Economics, "Econometric efficiency analysis of NIE's indirect costs and R&M costs", June 2011

3 CEPA, SKM and PKF, "NIAUR – Opex evaluation, efficiency assessment of NIE's operating expenditure", October 2011

1.2 Overview of our approach to this critique

In this report we undertake a detailed review of CEPA's analysis. We identify what we understand to be the main differences in approach between our work and CEPA's together with our view of whether the changes made by CEPA in their analysis are reasonable or otherwise. We also consider whether CEPA's approach is appropriate given the way in which their results have been embedded in the Utility Regulator's analysis. Based on this assessment we present an updated efficiency analysis. Finally, we present updated conclusions regarding NIE's efficiency with respect to its indirect expenditure, including our view on the appropriate value for an "efficiency factor".

As noted above, Frontier provided CEPA with access to all of our underlying calculations in order to facilitate the Utility Regulator's review. CEPA has told us that they are unable to provide complete access to their work since some of the data they used is confidential – we have therefore been provided with access to only those parts of CEPA's work that are not confidential. As a consequence we have been unable to replicate exactly CEPA's analysis, although our own analysis has derived similar results when we adopt all of CEPA's proposed treatments.

Since we do not have access to CEPA's analysis, we continue to use our original analysis as a basis to proceed, although where relevant we have updated our approach to take account of issues raised by CEPA. In each case we have assessed whether we agree with CEPA's proposal and, where appropriate, we have consequently proposed changes to our methodology.

We have also updated the analysis to reflect the latest data now available from Ofgem (for the year 2010/11). We follow the same procedure here, showing the results on the basis of our original approach from last year, together with results that take account of revisions identified as a result of CEPA's work.

We are therefore able to provide a review of CEPA's approach and our assessment of whether it is reasonable, together with an updated view of NIE's efficiency based on a synthesis of our original approach and where relevant the different approach of CEPA.

The remainder of this report is comprised of the following sections:

- Section 2 provides a high level **summary** of our critique and our findings.
- In Section 3 we set out a **review of the approach adopted by CEPA** in their analysis and highlight in particular areas of disagreement.
- In Section 4 we present the **consequences of our review of CEPA for our analysis**, highlighting any changes that we believe are necessary as a result of the issues raised.

- Finally, in Section 5 we provide **updated efficiency analysis** and set out our view on the efficiency factor that should be applied to NIE.

2 Summary

This section provides an overview of our views following the completion of our critique of CEPA's analysis and some additional analysis.

Our original analysis remains sound and our conclusions from the original study have not been altered by this latest review. While CEPA has identified some minor changes to the NIE cost base that should be adopted, they have little effect on our results and/or conclusions.

The CEPA analysis significantly understates NIE's efficiency. The most significant drivers of this are certain unjustified additions to the cost base and the application of a regional wage adjustment.

CEPA has added all market opening costs incurred by NIE to its benchmarking. However the role of NIE in support of market opening is considerably broader than the role played by the GB DNOs. In order to ensure consistency with the GB peer group, it is only appropriate to add a small proportion of NIE's market opening costs to its cost base, consistent with the narrow role of GB DNOs.

There is a need for consistency between the coverage of the benchmarking and the use to which that benchmarking will be put. The Utility Regulator has disallowed a number of costs from its controllable opex baseline (such as excess overtime, certain billing charges, innovation schemes and the profit element of Powerteam's costs). Since these costs are excluded from the proposed baseline, it follows that they should also be excluded from the benchmarking. Otherwise there is the possibility that the efficiency discount to be applied to NIE's baseline could be inflated by costs that are excluded from the cost base to which this efficiency discount is applied.

We do not believe that it is reasonable to apply a regional wage adjustment without also taking account of other significant differences between regions. We have not undertaken an exhaustive analysis of the possible size of further regional differences. However, previous work commissioned by NIE together with the evidence in the public domain from other regulatory reviews indicates that the sparse dispersion of NIE's customers could increase their service costs significantly, relative to a typical GB DNO. Taking account of sparsity is likely to at least offset the effect of a regional wage adjustment. Given this, we believe that our original approach to benchmarking NIE's indirect costs, which assumed that regional advantages and disadvantages broadly cancel each other out, remains reasonable.

Notwithstanding the paragraphs above, we do not believe that CEPA's estimation or application of a regional wage adjustment has been undertaken appropriately. When a more reasonable adjustment is calculated and applied to all GB DNOs the effect of the regional wage adjustment is greatly reduced.

Neither CEPA nor the Utility Regulator has placed any weight on CEPA's benchmarking of total opex, which includes R&M costs. We recognise that benchmarking direct opex is not straightforward and that the high level cost driver variables we have used do not perfectly capture all the relevant cost drivers. However the results of such benchmarking can be regarded as broadly indicative of underlying performance and the extent of NIE's outperformance in this area – particularly in the context of their sparsely populated region – should be regarded as part of a holistic assessment of NIE's performance. It seems unreasonable to reject evidence of R&M efficiency as totally unreliable, in particular given that the Utility Regulator uses similar analysis to assess capital expenditure.

Taking account of these changes we find that NIE's indirect cost efficiency score remains broadly unchanged or marginally better. This is the case when we consider our original analysis for the price control base year (2009/10, NIE's costs compared to GB DNOs' allowances) and for 2010/11 (NIE's costs compared to outturn GB DNOs' costs 2010/11). NIE is ranked 3rd in 2009/10 and is ranked 4th in 2010/11. Given this conclusion, it is our view that there is no reasonable basis to apply a positive efficiency factor to NIE (equivalently, the appropriate efficiency factor should be 0%).

3 Review of CEPA's approach

CEPA's report for the Utility Regulator provides an overview of the approach they have adopted in order to benchmark NIE's operating costs. In this section we review their approach and identify where there:

- is no disagreement or reasonable similarity in approach;
- are areas of disagreement over how to proceed; and
- is a lack of consistency between the CEPA analysis (and/or the Frontier analysis) and the way in which the Utility Regulator has used the analysis in its Draft Determination.

CEPA has told us that they are unable to provide complete access to their work since some of the data they used is confidential – we have therefore been provided with access to only those parts of CEPA's work that are not confidential. As a consequence we have been unable to replicate exactly CEPA's analysis, although our own analysis has derived similar results when we adopt all of CEPA's proposed treatments. While we cannot completely reproduce CEPA's analysis, we believe we have an acceptable level of understanding of their work to complete our review.

3.1 Areas where there is no disagreement

Both Frontier and CEPA have adopted a similar **general approach** to undertaking their benchmarking analysis. We have both applied a simple regression technique making use of a high level "scale" cost driver.

CEPA has made use of a **panel** approach (comprised of 2 years) whereas in our indirects analysis we have used a **cross section** (note that we used both panel and cross section to assess NIE's R&M efficiency). If CEPA are able to make available to us their data we would like to investigate whether significantly different results would arise from a simple cross-sectional analysis. However, prima facie, we do not presently anticipate that this is a significant area of disagreement.

Both Frontier and CEPA have used **the same sample** for comparison, i.e. the 14 GB DNOs.

CEPA has reviewed the detailed **cost mapping** that we have undertaken in order to develop an estimate of NIE's costs on a GB equivalent basis. CEPA's view is that this mapping is robust, so this provides a further area of agreement. As we describe below, there is some disagreement over certain additions to NIE's cost base that CEPA has made.

CEPA has also agreed that the adjustments made to account for **activities not included in the GB comparator data** (275kV transmission, connections and metering) are reasonable.

There is **limited disagreement over the cost driver** that should be adopted. In our work we have used the CSV. CEPA has stated a preference for MEAV, but has used CSV as a cross-check on its work. CEPA say that they are unable to provide us with the MEAV data they have used since it is confidential. However, from a review of CEPA's results, it seems clear that there is little difference between their results using CSV and using MEAV. Consequently we do not regard this, at present, as an area of significant contention.

CEPA has reported and emphasised the gap it has found between NIE's costs and the costs consistent with the upper quartile in the sample. In our work we have not discussed whether the upper quartile is the appropriate target for NIE, should it be required to bear an efficiency "catch up" target, since NIE's performance was already consistent with the upper quartile in our analysis. As we describe below, since NIE continues to perform at that level in our updated analysis, we again take no position on this question.

3.2 Areas where we disagree

CEPA has stated a preference for **analysing a different year**, i.e. 2008/9 rather than 2009/10. CEPA state that this should be preferred since at the time our work was undertaken, outturn cost data for the GB DNOs was not available for 2009/10, and they do not regard a benchmark against allowances as reasonable. We remain of the view that this approach is reasonable. However, as we describe below, we have now updated our analysis to include the year 2010/11, for which Ofgem has released GB DNO cost data.

Related to this first point, CEPA has stated that it would not have included Ofgem's allowance for **Work Force Renewal** as we did in our analysis of 2009/10. We maintain that this addition is reasonable. Work Force Renewal is clearly a recoverable indirect cost for the GB DNOs and for NIE and in order to ensure comparability it is reasonable to include all indirect costs without arbitrary deductions. CEPA note that their position on this has no impact on their own analysis.

CEPA has added all **market opening** costs to NIE's benchmarked cost base, whereas they were excluded from our analysis. We accept that it is reasonable to add a proportion of NIE's market opening costs to our analysis. However, as we discuss below, we believe that proportion is small.

CEPA has included a significant **regional wage adjustment** within its analysis, but has taken no account of **other potentially significant regional factors**. If CEPA wishes to include a regional wage adjustment it should also take account of, for example, the extra costs created by the sparsity of NIE's operating region.

Notwithstanding our observations on regional factors, we do not agree that CEPA has derived a **reasonable estimate of wage differences**. Furthermore, we do not believe that CEPA has applied its estimate of wage differences in a methodologically robust manner.

CEPA has indicated that its **analysis of total opex**, which includes R&M as well as indirects, is **less reliable** than its benchmarking of indirects alone. Consequently, the Utility Regulator has chosen to place no weight on those results. While this is not a critique of CEPA, we do not believe that the results for R&M are so unreliable as to render them wholly uninformative, in particular given NIE's very strong performance in that area. Indeed, our benchmarking is likely to understate NIE's R&M efficiency since we did not take account of the reduction in NIE's net costs arising from third party contributions[4]. Finally, CEPA do not appear to have considered the results of PB Power's benchmarking of NIE's tree cutting, which is a significant proportion of R&M. On a cost per span cut basis PB Power found NIE to be the third lowest in the GB sample and approximately half the cost of average GB practice. Taken together, we believe this provides evidence of highly efficient R&M performance that should be taken into account by the Utility Regulator.

3.3 Areas where CEPA's approach is inappropriate, given the Utility Regulator's use of the analysis

CEPA has included **Powerteam profit margin** within NIE's benchmarked cost base, an addition of £1mn. Since the Utility Regulator has indicated that it intends to discontinue allowing the recovery of this profit term in RP5, the inclusion of this cost in CEPA's benchmarking results in an inconsistency between the efficiency factor the Utility Regulator has derived and applied from CEPA's results and the cost base to which that is applied. Given the Utility Regulator's intended use of the benchmarking analysis, notwithstanding our other observations, the CEPA analysis should be rerun without this profit term. Powerteam profit was excluded from our analysis and we continue to adopt this treatment.

By applying similar logic, we have also adjusted our analysis of 2009/10 to reflect **other disallowances** the Utility Regulator is minded to make from NIE's proposed base opex. These relate to:

4 Where faults are caused by the actions of third parties, it is common practice for the utility to seek to recover the cost of rectifying the fault from that third party. NIE records this in its accounts as income from tort and received £1.14mn in 2009/10. We have confirmed with Ofgem that their accounting treatment of such income is to report costs net of income, whereas in our analysis we reported the gross cost before such income for NIE. Consequently, our analysis will underestimate NIE's efficiency.

- excess overtime (£0.7mn);
- billing charges (£0.6mn);

Since CEPA analysed 2008/09, it is not clear that these changes have a consequence for their analysis. However, we have reflected our knowledge of how the Utility Regulator intends to use this efficiency analysis in our updated work reported below.

4 Consequences for updating our analysis

We have updated our original efficiency analysis to take into account the issues raised by CEPA.

In this section we describe the changes we have made to our original efficiency analysis and explain how these changes compare with the methodology proposed by CEPA in their own analysis.

4.1 Base year for analysis

We still use 2009/10 as the base year of our updated efficiency analysis. We do this to preserve consistency and comparability with the results we obtained in our original analysis last year and since we believe our approach remains reasonable. However, actual cost data for 2010/11 has become available and we have extended our efficiency analysis to include 2010/11 too.

4.2 Scope of the NIE cost base

CEPA has added some additional elements to the cost base of NIE and undertaken a sensitivity analysis on the assumed proportion of Powerteam indirect costs attributable to connections.

Market opening costs

CEPA added £2.5mn to the cost base of NIE's indirect expenditures to reflect the cost of the services provided by NIE in support of retail market opening. We argue that this cost addition should only include the costs related to the services that are undertaken by both NIE and the GB DNOs in order to ensure comparability. Only Metering Point Administration Service is provided by the GB DNOs under their market opening activity. NIE's costs to provide this service were £0.13mn in 2009/10 and £0.185mn in 2010/11. We have added these amounts to the NIE's indirect expenditures in the two years for which we are updating our efficiency analysis.

Connection costs

CEPA has undertaken a sensitivity analysis around the assumed proportion of Powerteam indirect costs that can be attributed to connections. In our original analysis we estimated that approximately 20% of Powerteam indirect costs were related to connections. CEPA has used this proportion to deduct the costs related to the connections activity from the NIE's cost base. Additionally, CEPA has modelled connections costs to be 15% and 25% of Powerteam indirect costs. We still believe that the 20% share of Powerteam indirect costs attributable to

connections is robust and have not changed the approach in our updated efficiency analysis.

4.3 Relevant regional factors

Regional wage adjustments

CEPA has added £3.2mn to NIE's benchmarked cost base to reflect the Utility Regulator's view of the lower labour cost it enjoys. This amount has been calculated using the relative wage differential between Northern Ireland and the United Kingdom, over the period 2007 to 2010, and using a combination of professional categories that CEPA considers reasonably reflects NIE's labour force. The source data for this estimation is the Annual Survey of Hours and Earnings (ASHE), collected by ONS in GB and DETI in NI. CEPA has used data on mean weekly gross pay as the basis for its calculations of regional wage differences. Using this approach CEPA estimates that the wage difference between NI and UK is approximately 10% (CEPA's paper shows a correction of 0.91, the 10% is calculated as [(1/0.91)-1].

The £3.2mn adjustment reported in CEPA's paper has been applied to NIE's total opex. While we wait for the full disclosure of CEPA analysis, we have estimated that this adjustment would be around £2.4mn for indirects alone.[5]

As noted above, it is not reasonable to include a regional wage adjustment without also taking into account of other regional factors. Nevertheless, in order to assess its effect, we have updated our analysis using the following treatment for regional wage differences.

In discussion with NIE we have identified the SOC codes that correspond to the types of labour actually employed by NIE. These professional categories and SOC codes are:

- Electrical engineers – SOC 2123
- Electrical/electronics technicians - SOC 3112
- Electricians, Electrical Fitters - SOC 5241
- Lines repairers and cable jointers – SOC 5243
- Electrical/electronics engineers n.e.c. – SOC 5249
- Administrative occupations – SOC 41

5 This is the 10% wage correction on the payroll amount included within NIE's indirects. Indirects payroll has been calculated as 64% (CEPA refers to an approximate payroll share of two-thirds) of "indirect costs less connection indirect costs" (£39.9mn, see CEPA Table B.1.) less 7.5% (i.e. the adjustment to remove transmission).

- Heavy goods vehicle drivers – SOC 8211
- Labourers in Process and Plant Operations n.e.c. - SOC 9139
- Other Goods Handling and Storage Occupations - SOC 9149

In NIE's view the above set of codes are reasonably reflective of the underlying nature of work undertaken by a large proportion of the NIE workforce (approximately 68%). It is NIE's view that for the remainder of their workforce, there is no sufficiently close SOC, i.e. no relevant data obviously exists in the available national statistics. For the set of SOC that NIE regards as directly relevant, we have completed a calculation to assess differences in labour costs that arise between Northern Ireland and the UK. To complete this analysis we have used the weights presented in **Table 1**, which are based on NIE's FTEs.

We have used hourly gross pay, instead of weekly gross pay, since hourly wages are more likely to capture potentially important differences in working practices (such as differences in specified working hours).

Table 1. Weights used in calculation of regional wage differences

Professional category	SOC code	Weights (based on NIE's FTE)
Electrical engineers	2123	**19%**
Electrical/electronics technicians	3112	**3%**
Electricians, Electrical Fitters	5241	**4%**
Lines repairers and cable jointers	5243	**31%**
Electrical/electronics engineers n.e.c.	5249	**2%**
Administrative occupations	41	**5%**
Heavy goods vehicle drivers	8211	**1%**
Labourers in Process and Plant Operations n.e.c	9139	**1%**
Other Goods Handling and Storage Occupations	9149	**2%**

Source: NIE

This approach results in estimated labour differences between Northern Ireland and the UK between 2006 and 2011 of between 1.6% (mean) and 2.5% (median), i.e. the cost of this mix of labour is slightly lower in Northern Ireland. On the more conservative basis (i.e. 2.5% difference), this analysis would increase NIE's cost base by £0.6mn, instead of the approximately £2.4mn difference applied by CEPA.

Consequences for updating our analysis

While it is NIE's view that for the remainder of their work force (i.e. the remaining 32%) there is no sufficiently close SOC categories for which data is available, we have also undertaken an analysis that allocates all of NIE's work force to some SOC code. To be clear, we recognise the limits of analysis of this kind, given the potential lack of comparability between roles and responsibilities at NIE and within the SOCs, but we considered it was important to assess whether the exclusion of a proportion of the work force could influence our estimate of any regional differences in wages. Consequently, we have repeated the analysis assigning previously unassigned FTEs to the SOCs that might be at least indicative of the relevant NIE position. In order to do this, we made use of an additional SOC category, "Production Managers" (code SOC-112).

Under a full allocation approach the estimated labour differences between Northern Ireland and the UK between 2006 and 2011 are between 1.4% (mean) and 2.3% (median). Given this result, and in order to be conservative, we have made use of the larger estimated regional differences derived above in the update of our analysis presented below.

Sparsity

CEPA has not considered any other regional differences apart from differences in labour costs. This is unreasonable as there are a range of other regional factors that clearly disadvantage NIE, including for example sparsity. NIE itself commissioned a report (the NERA report January 2001) for RP3 showing that the sparsity of its network could add between £6mn and £10mn to its total costs. There is also evidence from other regulatory reviews of additional costs caused by sparsity.

- The Utility Regulator itself considered and adjustment of around£7mn on NI Water during PC10 based on the size of its water network and the relative low number of customers it serves.

- Ofgem also considered sparsity as an special factor during DPCR5, adjusting the benchmarked indirect costs of SSE Hydro by £2mn.

- Scotia Gas has recently submitted a report during RIIO-GD1 in which it shows that the sparsity of its network is a source of additional costs, estimated to be around £2.3mn.

On the basis of this review, an adjustment for sparsity on NIE's costs would be at least as large as the adjustment CEPA made to control for regional wage differences.

4.4 Issues related to how the efficiency analysis is used

Powerteam profits

CEPA has included the share of allowed Powerteam profits that are passed on to customers (50% of allowed profits) within NIE's benchmarked cost base.

It is not appropriate to include the profit element of Powerteam costs in the benchmarking analysis given the exclusion of these costs from the baseline opex. On the basis of this, we have not added any amount to the cost base of NIE's indirect expenditures to account for the share of Powerteam profits passed on to customers.

Other items excluded from the baseline by UR (excess overtime, billing charges)

The draft proposals exclude allowances for certain cost items like excess overtime and billing costs (Table 10.3 in the Draft Determination). These costs were included in our original benchmarking exercise in May 2011. As in the case of the Powerteam profits, since these costs are excluded from the proposed baseline, it follows that they should also be excluded from the benchmarking. In our updated benchmarking exercise we have excluded these costs from the cost base of NIE's indirect expenditures. We have not excluded these costs from our analysis of 2010/11 as we do not have any reference of excluded cost allowances for this year. We note that this would potentially lead to an underestimation of NIE's efficiency in that year.

4.5 Choice of cost driver

The benchmarking exercise by CEPA has used two different cost drivers, the MEAV and the CSV used by Ofgem in DPCR5. CEPA uses the MEAV as the main cost driver and the CSV as a cross-check. The results obtained by CEPA under the two cost drivers are fairly similar. In our original benchmarking exercise we used the CSV as cost driver.

CEPA has not shared with us the MEAV it has used as cost drivers in its benchmarking analysis. However, we believe that given the similar results obtained by CEPA under both cost drivers, it is acceptable to use the CSV in our updated analysis.

5 Results

In this section we provide an update to our previous analysis of indirect costs. We modify our analysis of 2009/10 in line with the discussion in Section 4. We also provide results for 2010/11, which is possible now given the latest information that has become available from Ofgem.

5.1 Updated analysis for year 2009/10

Table 2 shows the results of our updated efficiency benchmarking of NIE's indirect costs for year 2009/10. The GB cost data is still based on Ofgem allowances. We show various sensitivities starting with the results obtained in the base case of our original analysis. These sensitivities are presented incrementally, each based on a change from the previous sensitivity (except sensitivities 4 and 5 which present two alternatives for implementing a regional wage adjustment). The first sensitivity reproduces the results obtained in the base case of our original analysis. The second sensitivity shows the impact of adding the market opening costs to NIE's cost base – this impact is very limited. The third sensitivity shows the impact of excluding the actual costs of the items disallowed by the Regulator from NIE's proposed opex base. The fourth sensitivity includes the regional wage adjustment implemented by CEPA in its analysis. The fifth sensitivity is an alternative to the fourth and includes the revised regional wage adjustment described in the previous section.

Table 2. Benchmarking results for indirect costs in 2009/10

	Sensitivity	NIE "efficiency score	NIE "efficiency rank
1	Base case in May 2011	90%	4
2	As **1** plus revised market opening costs	90%	4
3	As **2** excluding disallowed items (excess overtime and billing charges)	88%	3
4	As **3** with CEPA's regional wage adjustment	93%	6
5	As **3** with revised regional wage adjustment	90%	3

Source: Frontier Economics

We have not presented results that take account of sparsity at this stage. However, an adjustment of approximately £6mn to NIE's cost base would result in an efficiency score below 90%, even using CEPA's regional wage adjustment.

5.2 Updated analysis for year 2010/11

Table 3 shows the results of the efficiency benchmarking of NIE's indirect costs for year 2010/11. In contract with 2009/10, we use actual cost data for the GB DNOs as reported by Ofgem.[6] We also present a number of sensitivities, starting with the case that mirrors our base case in our original analysis but using year 2010/11 and actual cost data for NIE and the GB DNOs. The second, third and fourth sensitivities correspond to the second, fourth and fifth sensitivities in **Table 2**

Table 3. Benchmarking results for indirect costs in 2010/11

	Sensitivity	NIE "efficiency score	NIE "efficiency rank
1	Base case in May 2011 (using year 2010/11)	92%	4
2	As **1** plus market opening costs	92%	4
3	As **2** with CEPA's regional wage adjustment	97%	7
4	As **2** with revised regional wage adjustment	93%	4

Source: Frontier Economics

We have not presented results that take account of sparsity at this stage. However, an adjustment of approximately £6mn to NIE's cost base would result in an efficiency score below 94%, even using CEPA's regional wage adjustment.

5.3 Updated assessment of the efficiency of NIE's indirect costs

Given our updated analysis, our view is that NIE's indirect costs are efficient and its performance is consistent with the upper quartile in years 2009/10 and 2010/11. This contrasts with the results obtained by CEPA.

6 Ofgem, Electricity Distribution Annual Report for 2010-11, March 2012.

Table 4. Comparison of results

Scenario	NIE "efficiency score	NIE "efficiency rank	Upper quartile
CEPA base case (CSV MEAV)	104%	9	90%
Updated benchmarking for 2009/10 (sensitivity 5 in **Table 2**)	90%	3	90%
Updated benchmarking for 2010/11 (sensitivity 4 in **Table 3**)	93%	4	94%

Source: Frontier Economics

In view of the results obtained in our updated efficiency analysis our view is that the efficiency factor that should be applied to NIE's controllable opex is zero.

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APPENDIX 4A1

REVIEW OF THE UTILITY REGULATOR'S BOTTOM UP PROJECT ASSESSMENT

APPENDIX 4A1 – REVIEW OF THE UTILITY REGULATOR'S BOTTOM UP PROJECT ASSESSMENT

Overview

Chapter 4 of NIE's Response to the Draft Determination outlines NIE's concerns with respect to the Utility Regulator's bottom up approach to determining NIE's capex allowance.

This Appendix considers general aspects of the Utility Regulator's bottom up assessment and then sets out a project-by-project review of the proposed disallowances.

Change of Licence Standards

The Utility Regulator has proposed to disallow expenditure for several network reinforcement schemes by reference to one or other of the following statements:

- "*pending technical review regarding need (probabilistic v deterministic)*";
- "*Reassess resupply issue to identify if there is a problem when a probabilistic methodology applied.*"

The network is currently planned to a deterministic network planning standard approved by the Utility Regulator under NIE's licence. The adoption of a probabilistic network planning standard would require the Utility Regulator to approve a change to NIE's licence standards. Should NIE apply for such a change, it would be necessary to demonstrate to the Utility Regulator that over a long period of time, probably several regulatory periods, that network integrity would be unaffected, that network reinforcement costs would be lower and that there would be no increase in network constraint costs.

To the best of our knowledge, no other UK or Republic of Ireland electricity utility uses a probabilistic network standard.

It is not possible for either NIE or the Utility Regulator to predict what impact a change in network planning standard would have on network reinforcement costs either in the short term or long term (or indeed on the ability of the networks to transmit or distribute electricity) and it would not be prudent for a price review allowance to be based on speculation.

Should the Utility Regulator wish to take forward a change in the network planning standard, the proper process to follow would be:

- for NIE to bring forward a proposal for the adoption of a probabilistic network planning standard with full justification for the change including the impact on

network capacity and operability together with an assessment of the savings to be realised;

- for the Utility Regulator to consult on the proposal with stakeholders including SONI; and

- if and when it is decided to proceed, to agree and then to make the requisite licence modifications.

Such a process would take a considerable period of time, particularly the analysis to investigate the impact on network reinforcement costs against a range of probabilistic variables. In the meantime, the Price Review allowance should be based on the licence standards currently approved.

Errors

The failure on the part of the Utility Regulator to take account of information supplied by NIE has resulted in avoidable errors in setting allowances.

This has occurred in a number of load-related cases where the Utility Regulator states that firm capacity of HV substations has not or will not be exceeded and therefore no reinforcement is required. As NIE has explained, it is the circuits that supply the substations that are overloaded and which give rise to network constraints. In each of these instances, the project is required to address an existing loading issue which will be exacerbated with demand growth during the RP5 period.

For LV load-related expenditure, the Utility Regulator states that there was neither justification of need nor any historical data. That is not correct: NIE has provided the Utility Regulator with clear evidence of need including:

- details of 140 network deficiencies in town centre networks;

- details of 78 transformers that have been categorised as being at risk of overload; and

- the requirements to address voltage complaints arising due to endemic[1] growth on the network[2], based on 5 year average expenditure[3].

The need for each investment is individually outlined and costed and historic costs have been provided. It appears that the Utility Regulator has not reviewed investment requirements on a case by case basis as outlined in NIE's submission.

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[1] 'Endemic Growth' is the term used to describe the incremental growth due to existing customers acquiring additional electrical equipment such as freezers or due to property extensions as opposed to new load caused by domestic, commercial and industrial developments.

[2] The level of expenditure to address voltage complaints has not been affected by the economic downturn implying continued growth in domestic electricity consumption. Expenditure by year: 2007 - £237,648, 2008 - £314,079, 2009 - £373,250, 2010 - £297,939, 2011 - £331,606

[3] Average annual expenditure 2007 to 2011 of £0.31 million.

An increase in the cost of cut-out replacement has been disallowed on the basis that RPI will allow for inflation and that the 09/10 price should be applied. However the submission clearly explains that some cut-outs can only be replaced if a section of service cable is also replaced at additional cost and a breakdown of volumes and associated unit costs has been provided. The Utility Regulator does not appear to have taken this information into account and instead has concluded that NIE has forecast increased unit rates due to inflation.

Expenditure has been disallowed because the Utility Regulator considers that condition information has not been provided – viz *"No condition information provided or explanation of how the thresholds for investment were established. Amounts reduced accordingly."* This assertion has been used to disallow significant urgent expenditure on secondary substation asset replacement (approximately £20 million). In fact, comprehensive condition information had been provided by NIE.

Arbitrary Disallowances

Disallowances have been determined on an apparently arbitrary basis with no analysis to indicate that the proposed allowance would be adequate. This has occurred in a number of asset categories.

The proposed allowance for distribution network alterations arising from the introduction of the ESQCR is 50% of the estimated cost on the basis that *"risk assessments have not yet been completed".* The 50% disallowance appears arbitrary and the Utility Regulator has not provided any analysis to show why this sum is adequate. NIE would be very exposed if it attempted to restrict expenditure against safety-driven legislation to half of the amount estimated to be necessary.

The single largest proposed cut is against distribution asset replacement. Of the £68 million submitted by NIE for 11kV Overhead line Refurbishment, the Utility Regulator believes that £25 million should be adequate. The following comment was provided:

> *"Concerned by the increase in unit costs for RP5 v RP4. The re-engineer programme was only commenced during RP4 and we have not been provided with evidence that demonstrates that it is value for money, and this is not referenced in the "supporting" study."*

The sum of £25 million proposed is less than half of that spent during RP4 on the 11kV overhead lines in order to prevent the network from deteriorating. Once the amount required for essential tree cutting (approximately £21 million) is deducted, the balance available for replacing decayed poles and other components is grossly inadequate. The Utility Regulator has not explained how the amount of £25 million was determined and it is clearly inadequate to prevent serious network deterioration and related risks.

Our BPQ submission explained that some overhead lines were in such a poor condition that complete rebuilding associated with conductor replacement was

required, any lesser intervention being ineffective. This is not a question of whether the expenditure is value for money - the work must of course be delivered efficiently - but rather that the expenditure is unavoidable if the network is to be prevented from deteriorating into a state of disrepair which is likely to result in NIE being prosecuted for failing to comply with its statutory duties. In addition, the overhead line reengineering programme[4] commenced in 2005 and this, together with the other overhead line strategies of refurbishment and Targeted Asset Replacement[5], have been fundamental in driving the current level of overhead line network performance.

The Utility Regulator has disallowed 66% of the estimated expenditure required for LV overhead lines with no logical explanation. The Utility Regulator states:

> *"While we accept need for work on the LV network, the unit costs of work should start to reduce as the benefits of the first cycle of refurbishment are seen and the benefits of the first cycle of refurbishment should be explicitly reflected in the submission."*

No rationale has been provided as to why 33% of the estimate is considered adequate.

The following table shows the implied cycle times for distribution overhead line refurbishment post financing of tree cutting carried out in conjunction with the programmed work. The implied refurbishment cycle is over 66 years for 33kV lines and over 176 years for 11kV lines. By contrast, NIE has been operating a 15-year cycle for refurbishment since privatisation and the DNO cycle times range from 10 to 15 years.

Table 1 – Overhead Line Implied Refurbishment Cycles

	NIE Submission			Utility Regulator		
£m	**Total Submission**	**Mandatory Tree cutting**	**Balance available for pole and component replacement**	**Proposed Allowance**	**Balance available for pole and component replacement**	**Implied Refurbishment Cycle (Years)**
33kV	11.5	3.1	8.4	5	1.9	66.3
11kV	68	21	47	25	4	176.3
LV	21.4	8.1	13.3	7	0	Inadequate even to cut trees

[4] Reengineering is required when small cross section conductors are to be replaced with larger ones required by modern overhead line standards.
[5] Targeted Asset Replacement includes tree cutting and urgent replacement work such as the replacement of a broken stay.

Inconsistency

The Utility Regulator has allowed replacement of certain sections of 33kV tower line whereas other sections in similar condition have been disallowed with no apparent justification for the different treatment. For example, the Utility Regulator has only granted allowance for the Holestone to Kells section of Ballyclare-Ballymena 33kV line, whilst the sections at either end, which are in the same condition, have been disallowed.

A similar situation applies on the transmission network where the Utility Regulator suggests that some assets should be replaced but that others in a similar condition should remain in service.

Poor Asset Management Judgement

NIE had prioritised 32 Primary Transformers for replacement. The Utility Regulator said - *"No explanation provided about how the list was selected. Particular concern regarding impact of consequence score on selection. Allowance to cover all sites with a risk score greater than or equal to 20."*

The Utility Regulator has confused the concept of 'Risk' with 'Probability of Failure'[6]. The Utility Regulator states that they have "*examined the parameters involved in the calculation of the probability scores*" and "*are of the opinion that the various combinations of factors that would result in a score of 20 are significant enough to justify their inclusion for replacement during RP5*". However, there are some 52 primary transformers on the NIE system with a probability score of 20, a much higher number than NIE propose to replace. Despite this, the Utility Regulator has proposed an allowance of 69% of the amount submitted by NIE. Using the Utility Regulator criterion for replacement, a sum of £16 million would be required to replace the transformers rather than the £10 million requested by NIE. NIE agrees that a probability score of 20 or more is a cause of concern but NIE was prepared to manage the risk associated with those transformers remaining in service by closely monitoring condition until those transformers could be replaced during RP6.

The Utility Regulator has also been inconsistent in its treatment of risk. The Utility Regulator has adopted the approach referred to above (i.e. consideration of 'probability of failure' only and not 'consequences of failure') in respect of only one of the ten categories of risk table submitted by NIE.

The Utility Regulator's proposed approach to tower painting is another example of poor asset management judgement and would prevent NIE from achieving the maximum potential tower life. The Utility Regulator has suggested a 100% disallowance for tower painting both at 275kV and 110kV. It has long been accepted in the industry that deferring tower painting is a "penny wise pound foolish" approach

[6] In asset management risk assessments, 'Risk' is taken to be a function of 'Probability of Failure' and 'Consequences of Failure'

that puts the towers at risk, resulting in need for complete replacement at great expense and with severe difficulties in implementing due to outage difficulties.

Unintended Consequences

Some of the Utility Regulator proposals would have unintended consequences for constraint costs, for example;

Reduction in 110kV substation refurbishment

The reduction in allowance against 110kV switchgear replacement and overhead lines suggests upgrades will be rather piecemeal in approach. This approach is expected to have implications for wind generation constraints. One of the projects included in the plan was the full refurbishment of Dungannon Main. This substation is a key node in the export of wind power from the west of the province.

Reduction in 110kV overhead line refurbishment

The reduced allowance for 110kV conductor replacement has a direct implication on the Drumnakelly – Dungannon circuits. The extent of wind generation seeking connection has required the development of a short term line rating policy. This policy however assumes that conductor is in good condition. It is possible that in the event that the conductor on the Dungannon – Drumnakelly circuit is not replaced NIE will not be able to apply a short term rating policy to this circuit. Consequently to protect the circuit SONI would be required to constrain wind generators pre-fault.

Ballylumford – Eden – Carnmoney

The upgrade of the above circuits has been disallowed. This may have implications for the way in which SONI dispatch generation at Ballylumford. Recently the 80MW limit on Moyle exporting from Northern Ireland was lifted by National Grid, and is now based on the Connection Agreement figure of 300MW. This has resulted in the above circuits being even more at risk of overload.

Project By Project review of the Utility Regulator's proposed Disallowances

D6 Distribution Tower Lines

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Distribution Tower Lines				
6	£2,253,500	35%	£788,725	Allow Holestone to Kells (£790,000) due to issues across an number of component types. This should provide data for further assessments. No link has been demonstrated between asset condition and investment plan. No indication of why 60% shackle wear is a problem, or the % of shackle wear found on those that have failed. Fault details not provided. No description of what "priority 1" is for replacement of equipment and how this has been determined to be an appropriate threshold. How has the risk been managed where there has been no earthwire for a period of time - no explanation provided as to why this is no longer acceptable.

Comments

It is illogical to provide finance for one section of line whilst refusing others when the justification is the same. The Utility Regulator has granted an allowance for the Holestone to Kells section of line but the sections at either end, Ballyclare to Holestone and Kells to Ballymena are in the same condition yet it is proposed to disallow expenditure. The Eden to Carrick line is in a worse condition than the Holestone to Kells, but it also has been disallowed.

The Utility Regulator has stated that there is no explanation from NIE as to why 60% shackle wear is a problem. NIE engineers have considerable experience in this area and have evidence to show that following the onset of detectable deterioration these components have a very rapid wear pattern. Climbing inspection data shows that these components can move from 20% wear to >80% wear within three years and that fittings with greater than 80% wear are on the verge of failure. The evidence shows that any of these components with 60% wear or greater are likely to reach the point of failure within the five years of RP5 if not replaced; therefore a program of the complete replacement of shackles with ≥60% wear is essential.

The Utility Regulator stated in its response that NIE had given no details of the prioritisation process. The condition methodology applied to distribution tower lines is identical to that applied to transmission tower lines. As detailed in NIE Strategy Paper D1 the condition categories for tower steelwork are as follows:

- Priority 5 refers to paint covering all of the surface although the overcoat may not be intact;
- Priority 4 refers to steel members having very light surface corrosion with the majority of coating intact;
- Priority 3 refers to steel members having light pitting and roughing on the edges, with the loss of the majority of the coatings and zinc layers. Painting would not be sufficient to give increased life;
- Priority 2 refers to steel members with significant pitting, where the loss of section is clearly visible round the edges; and
- Priority 1 refers to perforated elements with severe physical damage.

One section of the earthwire on the Ballyclare/Holestone/Ballymena line failed during the Easter 2010 Ice storm at which time NIE had already plans in place to replace the earthwire during RP5. This line also has some Hardex earthwire which traverses the M2 by-pass at Ballymena. (Hardex is an obsolete earthwire with an integral communication channel, which can be used for protection.) NIE has experience of several failures of Hardex earthwire including one notable failure at Mallusk in 2003. Hardex earthwire is also installed on the Inver/Cockle Row towerline, which is also scheduled for replacement during RP5. Since the 2003 incident, NIE has had a prioritised programme of Hardex replacement, dealing with the 110kV first.

The Utility Regulator's Draft Determination implies an unacceptable level of risk being imposed by the Utility Regulator on NIE.

D7 33kV Overhead Lines

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
33kV Overhead Lines				
7	£11,552,032	43%	£4,967,374	Allow £3478k for refurbishment TAR - no reason why frequency should be 3 years rather than 5 years (trees grow at the same speed), therefore reduce amount allowed to £1483k (= £2462 / 1.66). 33kV network has more redundancy than 11kV, therefore impact on consumers less than with 11kV. An activity repeated every 3 years could not be classified as capex with a 40 year depreciation. Justification for reengineering has not been received. Would require details of circuits. (note: RP4 figures do not identify the amount of re-engineering undertaken then and the study "supporting" the 5/15/45 year programme does not mention the 45 year re-engineering) **Total = £4961k (= 43%)** The first cycle of refurb iscomplete and the benefits of it should be explicitly refelcted in the resubmission. Note: there is an overlap with requests for F&E and reactive spend approved under seperate projects. Units of tree cutting are ambiguous (km surveyed, not volume of work). Measurement of deliverables to be addressed in resubmission.

Comments

Although increasing the cycle time for TAR will reduce the length of 33kV network addressed on an annual basis, the km unit rate will substantially increase as the volume of timber to be cut will be greater and the percentage of sites requiring an outage will also increase. Experience gained from benchmarking with GB DNOs and from the DTI ESQCR amendment consultation in 2006, has shown that a shorter duration between TAR visits not only helps to reduce the unit rate but also improves the level of acceptance by landowners. There are no savings to be made by increasing the cycle time. DNOs typically have 3 year tree cutting cycles both at 33kV and 11kV and a 1 year cut is in place for transmission circuits.

The Utility Regulator's comment on the amount of redundancy in the 33kV network shows a lack of appreciation for the investment driver. NIE has a statutory obligation under both the existing ESR and the proposed ESQCR to maintain an adequate clearance from trees to our overhead line network. The level of network redundancy does not reduce this statutory burden on NIE in any way.

The Utility Regulator has commented that “RP4 figures do not identify the amount of re-engineering undertaken”. NIE would refer to the additional data request to the Utility Regulator dated 8/6/2011, where the proposed volumes of re-engineering and the actual/LBE for RP4 are quoted.

Our strategy paper D3 clearly set out the requirement for reengineering –

> *“It is now clear that the current refurbishment programme with a specification that results in a low volume of conductor replacement will not adequately prevent network deterioration in the medium and longer term. Reconductoring and associated redesign is now required particularly on those circuits that are showing signs of extensive conductor deterioration. [Is this not self evident?] For clarity in presenting the additional costs involved and for reporting purposes, this programme element involving reconductoring is referred to as ‘re-engineering’.”*

The benefits of completing the first cycle of refurbishment were that deterioration was arrested, dangerous decayed poles were removed and the circuits brought to a condition suitable for a further prolonged period of service and that the unit costs used for the RP5 projection are based on those established during the second cycle of refurbishment.

The Utility Regulator's Draft Determination implies an unacceptable level of risk being imposed by the Utility Regulator on NIE with safety related issues on the distribution network not being addressed.

D8 11kV Overhead lines

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
11kV Overhead Lines				
8	£68,260,248	37%	£24,996,903	Allow £25 million to include sample rebuild for 11kV resilliance. Concerned by the increase in unit costs for RP5 v RP4. The re-engineer programme was only commenced during RP4 and we have not been provided with evidence that demonstrates that it is value for money, and this is not referenced in the "supporting" study. The benefits of the first cycle of refurb should be explicitly refelcted in the resubmission.

Comments

Tree cutting on the 11kV network is mandatory and is estimated to cost £21m in RP5.

The residual sum of £4m is inadequate to carry out any worthwhile network refurbishment. Likewise it could not be used to pilot a sample circuit rebuild for 11kV resilience since a large scale pilot in a number of geographic areas, carried out during all seasons is required to establish competitive and complete unit costs.

SKM have already concluded that NIE's unit costs, on a direct basis, are efficient compared to GB best practice. Further analysis of the unit costs associated with the overhead line programme is detailed in the PB unit cost benchmarking report.

D9 LV Overhead Lines

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
LV Lines				
9	£21,411,154	33%	£7,065,681	While we accept need for work on the LV network. The unit costs of work should start to reduce as the benefits of the first cycle of refurbishment are seen and the benefits of the first cycle of refurb should be explicitly reflected in the resubmission.

Comments

The Utility Regulator has provided no rationale for the proposed reductions, nor have they provided any details of modelling or benchmarking completed to support their reductions. The comments relating to the reducing cost of the work following the first cycle of refurbishment have no relevance and do not attempt to justify the proposed disallowance. The first cycle of refurbishment will not be complete for some time. The benefits of refurbishment will also be self-evident; refurbished circuits will have deterioration arrested, dangerous decayed poles will be removed and the circuits brought to a condition suitable for a further prolonged period of service.

NIE is obliged to cut trees on the LV network, replace decayed poles and replace any defective components as on overhead lines at other voltages. This expenditure is unavoidable and without it, safety related issues on the network would be unaddressed which is unacceptable.

Strategy Paper D4 provides detailed information on the projection.

D11 LV Cutouts

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
LV Cut-outs				
11	£1,832,000	76%	£1,392,320	Increase in unit cost is not justified (capex allowance will be increased by inflation from 2009/10 therefore the 09/10 price should be applied) **Allowed value = 8000 x £175 = £1.4 million (76%)** Subject to confirmation that these are not included in Fault & Emergency or Reactive spend (note the number that fail each year)

Comments

NIE identified the volume of cut out replacement required and the reason for differential costs, some replacements requiring part of the service cable to be replaced since the cut-outs are mounted too low to the ground.

The disallowance is based on an assumption that the average unit rate has increased due to inflation whereas NIE had explained that both simple and complex cut-out replacement was required, the latter costing significantly more due to the requirement to replace a section of service cable.

NIE has now completed the survey of cut-outs referred to in our submission (section 2.1 of paper D6). This has confirmed that there are approximately 23,500 obsolete cut-outs at domestic and SME customers' premises. Given that NIE has informed the Utility Regulator of the ongoing survey at the time of our submission, it would be appropriate for the Utility Regulator to take the findings into consideration in setting the allowance.

D12 Distribution Overhead Lines Fixed Costs

The Utility Regulator Proposal

Initial Proposals

Fund Number	4			
Distribution Overhead Lines Fixed Costs				
12	£18,063,754	0%	£0	This will be inlcuded in the percentage uplift for indirect costs.

Comments

The Utility Regulator has treated this category of expenditure along with the other overhead cost categories;

- T23 Transmission Design & Consultancy
- T41 Transmission Capitalised Overheads
- D20 Distribution Design & Consultancy
- D45 Distribution Capitalised Overheads

The Utility Regulator has scaled back these indirect costs on a linear basis to its proposed level of capital expenditure resulting in a determination of 35% of that requested.

This investment provision covers for the costs directly associated with the programming and management of the 33kV, 11kV and LV overhead line refurbishment programme with regard to the provision of preconstruction design, survey, wayleaving and patrolling services necessary for preparation of the detailed work programme on the distribution overhead line network

These programme costs include for:

- Collection of asset condition information which prioritises and drives the investment programme;
- Pre construction survey and wayleaving to provide detailed work plans for each circuit;
- Vegetation management – quantification and work plan development on a per circuit basis;
- Helicopter patrolling to identify defects, hazards and supplement the work plan; and

- Provision of mobile generators on overhead line outages to mitigate customer outages.

In the Utility Regulator's calculations, it has made an error and has omitted to include one of the five classes of indirect costs - the costs associated with distribution design and project management.

Indirect costs can be classified into the 3 separate categories (as defined in Ofgem's RIGs glossary[7]):

- Closely Associated (Engineering) - these costs can be regarded as broadly linear with the quantum of work on the network i.e. the number and complexity of the projects and programmes of work.

- Closely Associated (Other) - these costs are generally non- linear with some costs being generally fixed costs and others subject to step change depending on the size and scope of the work programme.

- Business Support Costs - these costs are not directly or indirectly proportional to the level of investment or quantum of work on the network but support the networks business

Given that indirects can be fixed, variable and step in nature, it is thus not appropriate for the Utility Regulator to apply a general linear scaling back based on the level of capital investment. NIE has calculated that based on the level of capex proposed by the Utility Regulator, the level of indirects in these categories should be more than double what it has proposed. It is not possible for NIE to plan, design and deliver the programme of works within this proposed allowance.

Until a final level of capital investment has been agreed, NIE would request that the Utility Regulator revisits the issue of indirects to arrive at a sensible level based on the specific nature of these costs.

[7] Glossary of Terms - Regulatory Instructions and Guidance: Version 2 - Ref: 75d/11

D13 Primary Plant

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Primary Plant				
13	£31,156,746	33%	£10,281,726	No explanation has been provided of the how the risk scores are converted to an investment plan. We accept the need for some work here, but without NIE demonstating that they understand and control the amount of risk and manage it in a cost effective manner.

Comments

In the NIE Strategy Papers, C4, C5, C6 and C14, the investment requirements were outlined for Primary Plant (including ancillaries) at 33kV sites. The papers covered the following equipment:

- 11kV circuit breakers at primary substations
- 6.6kV circuit breakers at primary substations (Belfast only)
- 33kV indoor circuit breakers
- 33kV outdoor circuit breakers

Papers C4-C6 clearly define the issues and options associated with these categories of assets and explain the risk ranking process.

NIE's response to the Utility Regulator in November 2011 fully described how corporate strategy and the investment planning process came together to develop an investment plan.

NIE Strategy Paper C14 outlines the ancillary equipment associated with C4-C6; the Utility Regulator response makes no reference to an allowance for ancillaries; these may have been grouped with the main Primary Plant.

Acceptance of the Utility Regulator proposals would mean that assets would be required to remain on the network well beyond their normal life expectancies and would have a higher level of risk associated with them than would be prudent, increasing the risk of injury to staff, contractors and potentially members of the public. This raft of asset replacement would be pushed back creating outage difficulties and higher operating costs in the interim. This in turn would have a knock-on effect and, based on the volume of work required during RP6, RP7, etc, would create difficulty in achieving delivery of future replacement.

No rationale or justification has been provided as to why the Utility Regulator considers that 33% of NIE's estimate for this work should be adequate and clearly it is not.

Nor is the level of risk the expenditure implies acceptable.

D14 Primary Transformers

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Primary Transformers				
14	£10,071,761	69%	£6,899,156	No explanation provided about how the list was selected. Particular concern regarding impact of consequence score on selection. Allowance to cover all sites with a risk score greater than or equal to 20.

Comments

The NIE Strategy Paper 'B3 - 33/11kV & 33/6.6kV Transformers' prioritised the replacement of these assets based on a risk ranking, being the multiple of the probability of failure and the consequence of failure. The Utility Regulator's response in the initial proposals appeared to reject the use of the consequence multiplier when assessing risk which prompted NIE to seek clarification.

In the Utility Regulator's response to the question 9.17 regarding NIE's approach to risk, it confirmed its rejection of the consequence multiplier and stated that the Utility Regulator

> *'are bound by a duty to protect individuals residing in rural areas. Rural populations would score lower on NIE's consequence matrix than individuals connected to similar equipment in an urban area due to population density. We have also already raised our concerns about the priority given to "important" customers under the scoring matrix. We therefore do not believe that we can take your consequence score into account when assessing investment requests.'*

As a result the Utility Regulator granted an allowance based on an apparently arbitrary probability threshold level of 20, although it states that it

> *'examined the parameters involved in the calculation of the probability scores and we are of the opinion that the various combinations of factors that would result in a score of 20 are significant enough to justify their inclusion for replacement during RP5.'*

If the Utility Regulator's probability threshold level of 20 were applied to NIE's population of primary transformers, it would permit more units to be replaced than the number initially requested, although the capex figure granted suggests that the Utility Regulator is not aware of the impact of this decision. Of the population of 396 Primary transformers, NIE requested the replacement of 32 during RP5. However, 52 transformers in the population have a probability of failure score of 20 or above.

From this NIE must conclude that, if the Utility Regulator's judgement is to be taken at face value, since the number of transformers meeting the Utility Regulator's criteria is greater than the number requested by NIE, the full requested allowance for 32 transformers should be granted.

D15 Secondary Substations

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Secondary Substations				
15	£37,807,990	41%	£15,350,044	No condition information provided, or explanation of how the thresholds for investment were established. Amounts reduced accordingly. (based on first column in table attached to q 14) item 1 = 50% item 2 = 50% item 3 = 25% item 4 = 15% item 5 = 20% item 6 = 0% item 7 = 30% item 8 = 100% item 9 = 50%

Comments

The Utility Regulator's proposals are to reduce the NIE request in 8 of the 9 categories; in one case (11kV sectionalisers) to 0%. Only LV wall mounted boards have been fully funded. However, no rationale is provided as to why these reductions are proposed.

In the NIE Strategy Papers, C7-C15, the investment requirements were outlined for Secondary Plant (including ancillaries) at 11kV, 6.6kV and LV distribution sites. The papers covered the following equipment:-

- 11kV and 6.6kV Ring Main Units
- 11kV and 6.6kV secondary switchboards
- 11kV and 6.6kV overhead fed ground mounted transformers
- 11kV and 6.6kV H-poles
- 11kV and 6.6kV 4-Poles
- 11kV sectionalisers
- LV plant (mini-pillars, section pillars and UDBs)
- LV wall mounted boards

The Utility Regulator had requested detailed costs for each item, based on a total output of 2200 units; this was provided by NIE. The Utility Regulator also suggested that safety had not been considered as a driver for these categories; however it is clear from NIE Strategy Papers C7-C15 that safety has been considered. In these papers, NIE gives specific defect information on various plant types within this group; furthermore, both national and NIE specific fault histories are provided.

The Utility Regulator has also stated that 'no condition information was provided'. The comprehensive condition information provided in the Strategy Papers, including in some cases photographic evidence, seems to have been overlooked.

The nature of the assets in this category is that they are customer facing, in public areas and often located in the most densely populated areas. Hence, failure of this type of equipment, especially that which is oil filled, has the potential to cause serious injury or death to members of the public or to the staff who operate it. NIE has experience of secondary oil filled equipment failing catastrophically in public places and spreading debris over a wide area.

There are in excess of 8000 secondary substation switching devices on the network of which approximately 10% are between 40 and 70 years old. Of the 500 units prioritised for replacement in RP5 (6.25% of the population), approximately 400 of them are subject to operational restrictions that cannot be removed through maintenance or repair.

The Utility Regulator's Draft Determination would imply that two thirds of mini pillars and section pillars that NIE considers essential to be replaced would have to remain on the network for a further period of 5 years. Such equipment is often located in built up areas where children play and they may climb or sit on the equipment or may even interfere with it by pushing an object through an aperture caused by corrosion. If housings are corroded there is an unacceptable risk of contact with live equipment. In RP4 there were 13 reported incidents where members of the public came into contact with live equipment through interference and unless these older assets are addressed, this is likely to increase in RP5.

The risk imposed by the expenditure level proposed is unacceptable.

D16 Distribution Cables

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Distribution Cables				
16	£4,948,000	35%	£1,731,800	scope is not clearly defined Holywood scheme not allowed. Items allowed are: sheath tests = £180k cables 147 & 148 = £350k monitoring (allow 50%) = £175k Leak detection = £300k - note we believe this should be an opex expense, but waiting for final policy to be defined 11 & 6.6 kV cables = 30% of £1172k (not enough information provided to allow full work) LV cables = 30% of £1247k Total = £1,730,700 = 35%

Comments

In paper E2 we have set out a strategic and modern approach to the management of our cable infrastructure. Our proposals include modest levels of cable replacement along with a number of condition monitoring and refurbishment proposals designed to maximise asset life while ensuring a safe and efficient network for customers.

Our proposal to refurbish cable circuits using modern techniques and materials will significantly reduce environmental risk and the risk of committing an environmental offence and will ensure that maximum asset life is achieved. No explanation has been given by the Utility Regulator for disallowance.

The replacement of Holywood West - Holywood East has been disallowed with an explanation from the Utility Regulator stating "scope not clearly defined". The primary driver identified in the Strategy Paper was network risk as a consequence of the exceptional depth that the cable is laid (c.4m). There is a heightened risk that failure of this cable will result in a prolonged outage to facilitate repair. The risk in this case is exacerbated particularly bearing in mind the topography of the circuit route and in the context of known problems of dielectric breakdown in mass impregnated cables of this vintage (Strategy paper E2 Section 2.2).

There is no explanation given by the Utility Regulator for the disallowance of L42T terminations. A recent assessment of the leaking L42T terminations from recovered units at Carmoney Main has identified the main cause to be cement seal failure. This results in cable fluid oil entering the termination box and causing over pressurisation. Subsequently the gaskets and seals are overstressed leading to failure and subsequent leak. In certain instances (relative to the profile of the cable route and load profile of the circuit) the box can drain of fluid which can result in live 33kV

copper connections being exposed to air, which increases the risk of flashover. This type of failure has been documented within the ENA NEDeRS.

No explanation has been given by the Utility Regulator for a 50% reduction in Condition Monitoring expenditure. Is the 50% reduction being challenged on cost or need? In the absence of a strategic replacement policy for 33kV cables this allowance is critical to asset life extension and risk mitigation.

No explanation has been given by the Utility Regulator for disallowance of the refurbishment/replacement of outdoor cable terminations. A catastrophic failure of a porcelain termination is extremely dangerous to both staff and public. The directors' enquiry into the porcelain sealing end failure at Castlereagh described shards of razor sharp porcelain being strewn over a wide spread area.

The explanation by the Utility Regulator for a 30% reduction in the allowance for 11&6.6kV cables is stated as "not enough information provided to allow full work". Total allowance from the Utility Regulator for this category is only £351k (sufficient to replace only 4.6km of cable). Details of specific areas/circuits have been given in the strategy paper including detail of condition issues.

The explanation by the Utility Regulator for a 30% reduction in the allowance for LV Cable replacement is stated as "not enough information provided to allow full work". The total allowance for this category is £347k (sufficient to replace only 4.25km of cable replacement). This does not even cover the replacement of non-conforming VB cable estimated at £516k (equivalent to 6km of replacement). VB main is now over 100 years old and does not have a metallic sheath making it non-compliant with modern day standards or ESR 1988.

The disallowances proposed are unjustified and unacceptable.

D19 Storms

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Storms				
19	£2,600,000	0%	£0	needs to align with opex, but should be managed within reactive an F&E

Comments

The Utility Regulator in its assessment appears to recognise the requirement for such costs but has disallowed the proposed expenditure on the basis that it expects them to be managed within the Reactive and F&E allowance.

This category of investment includes the cost of restoration of supplies though replacement of conductors, overhead line components, substation assets and repairs to underground cable faults from the effects of severe weather. This investment category covers for the occasions where due to the severity of the weather, NIE escalates its Incident Centre to manage such an event (smaller events are managed under the Distribution Fault and Emergency investment category).

The NIE network and the overhead network in particular is subject to adverse weather which can result in disruption to customers' supplies. Under severe wind, lightning, snow and ice conditions, faults are inevitable due to the significant dispersed overhead line network that comprises 70% of the distribution system.

NIE's escalation plan is put into effect when wind gusts are expected to reach 45 knots. The extent of damage on the network depends on a number of factors such as wind gusts, wind direction, time of year, duration etc. Experience has shown that it takes a storm with gusts in excess of 50 knots before significant numbers of faults are experienced with the majority of the damage being due to the impact of wind borne debris and falling trees. Ice accretion (build up of ice on overhead conductors) has been a significant issue over the past 2 winters. The weight of ice during ice accretion accompanied by high winds can result in overhead conductors falling. In addition the network experiences unplanned outages due to lightning which can cause damage and failure to overhead connected transformers, cable terminations and switchgear.

NIE has evidence that the network is being subjected to more severe weather events and storms are happening more often. During RP3, NIE experienced 18 storm escalations compared to 38 in RP4. NIE experienced three 'exceptional' weather events during RP4:

- the March 2010 ice storm;

- the January 2009 wind storm; and

- the ice accretion in December 2011.

The investment level proposed for RP5 is based on the average cost of escalated storm events from 2003 to 2009 (year of submission). It excludes the costs of 'Exceptional' weather events such as the Easter Ice Storm of 2010. NIE has proposed a 'Force Majeure' condition should apply in these situations and that costs of these events would be recovered outside the regulatory settlement for RP5.

The Utility Regulator's proposal is not acceptable as the Reactive and F&E allowance is again based on historic run-rate expenditure to cover reactive asset replacement and normal day to day fault and emergency activity. The Utility Regulator has made a token allowance within R&M for approx 60% of what was requested based on run rate.

The Utility Regulator has not recognised the significant costs associated with NIE's storm response costs. In addition, the Utility Regulator has appeared not to have recognised the potential impact of 'Exceptional weather events' resulting in a significant burden of risk on NIE to manage within a capped allowance.

D20 Distribution Design & Consultancy

The Utility Regulator Proposal

Initial Proposals

Fund Number	4			
Distribution Design & Consultancy				
20	£6,676,389	0%	£0	included within percentage uplift for indirect costs

Comments

The Utility Regulator has treated this category of expenditure along with the other overhead cost categories;

- T23 Transmission Design & Consultancy
- T41 Transmission Capitalised Overheads
- D12 Distribution Overhead Lines Fixed Costs
- D45 Distribution Capitalised Overheads

The Utility Regulator has scaled back these indirect costs on a linear basis to its proposed level of capital expenditure resulting in a determination of 35% of that requested.

This investment category covers for the direct cost associated with Distribution substation design and project management of capital projects and for certain projects, the use of specialised substation design consultancy.

The majority of NIE's design capability is in-house and is apportioned directly to the respective capital projects. In addition to NIE's internal design capability, NIE utilises the services of a number of specialised design consultants for production of high level and detailed substation designs.

The investment level proposed is based on the current RP4 period outturn costs with allowance made for the increased capital programme on distribution substation projects in RP5. In the Utility Regulator's calculations, it has made an error and has omitted to include one of the five classes of indirect costs - the costs associated with distribution design and project management - and thus their analysis is flawed.

Indirect costs can be classified into the 3 separate categories (as defined in Ofgem's RIGs glossary[8]):

[8] Glossary of Terms - Regulatory Instructions and Guidance: Version 2 - Ref: 75d/11

- Closely Associated (Engineering) - these costs can be regarded as broadly linear with the quantum of work on the network i.e. the number and complexity of the projects and programmes of work.

- Closely Associated (Other) - these costs are generally non- linear with some costs being generally fixed costs and others subject to step change depending on the size and scope of the work programme.

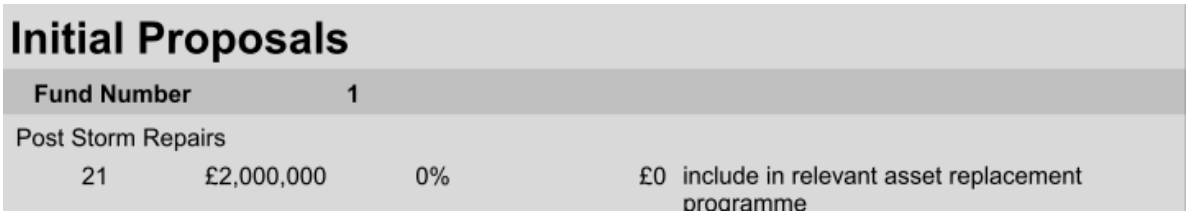
- Business Support Costs - these costs are not directly or indirectly proportional to the level of investment or quantum of work on the network but support the networks business

Given that indirects can be fixed, variable and step in nature, it is thus not appropriate for the Utility Regulator to apply a general linear scaling back based on the level of capital investment. NIE has calculated that based on the level of proposed capex by the Utility Regulator, the level of indirects in these categories should be more than double what it has proposed. It is not possible for NIE to plan, design and deliver the programme of works within this proposed allowance.

Until a final level of capital investment has been agreed, NIE would request that the Utility Regulator revisits the issue of indirects to arrive at a sensible level based on the specific nature of these costs.

D21 Post Storm Repairs

The Utility Regulator Proposal



Initial Proposals

Fund Number	1			
Post Storm Repairs				
21	£2,000,000	0%	£0	include in relevant asset replacement programme

Comments

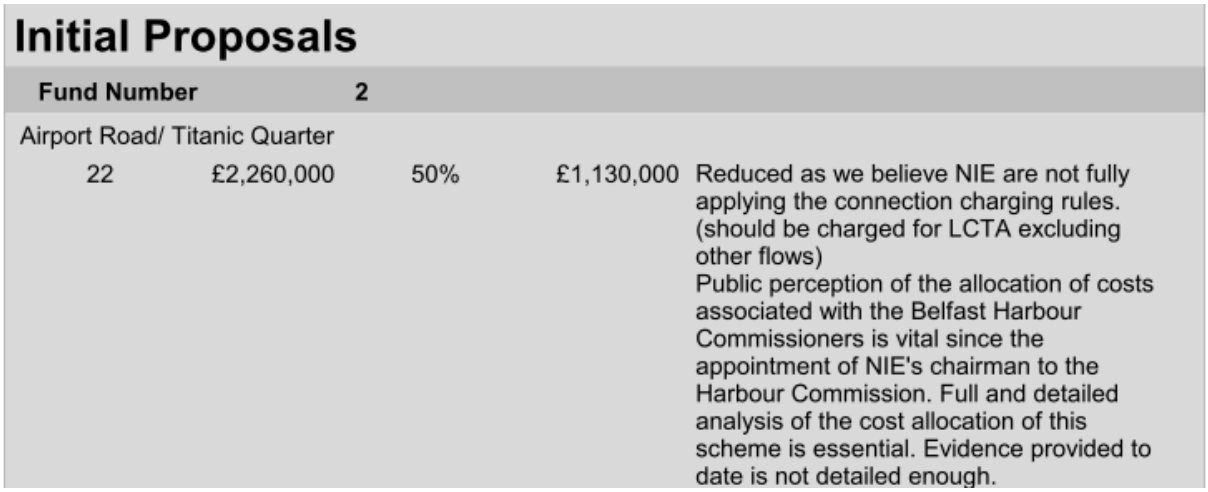
Expenditure of £2m on Post Storm Repairs is required to ensure compliance with statutory obligations.

The work needs to be completed in parallel with the refurbishment programmes since the intensity of this work is substantially different to that carried out under the overhead line asset replacement programmes.

The Utility Regulator has not recognised the legitimacy of such costs and the fact that post storm repairs have a significantly higher work content than refurbishment.

D22 Airport Road

The Utility Regulator Proposal



Initial Proposals

Fund Number				
Airport Road/ Titanic Quarter				
22	£2,260,000	50%	£1,130,000	Reduced as we believe NIE are not fully applying the connection charging rules. (should be charged for LCTA excluding other flows) Public perception of the allocation of costs associated with the Belfast Harbour Commissioners is vital since the appointment of NIE's chairman to the Harbour Commission. Full and detailed analysis of the cost allocation of this scheme is essential. Evidence provided to date is not detailed enough.

Comments

NIE does not accept that the Utility Regulator's proposals will lead to a satisfactory solution to the overloading issues that need to be addressed in the centre and east Belfast networks. Conversely, we believe they will lead to nugatory network expenditure and frustration for connection applicants.

Taking the Utility Regulator's approach, NIE would be required to continue adding demand until an application was received that had the potential to "break the camel's back". At that point, irrespective of the size of the demand that applicant would be required to fund all of the deep reinforcement. Clearly, unless the proposed increased demand was associated with a facility that was sufficiently significant to fund the reinforcement this will lead to a major impediment to development within the area. One also needs to be mindful that present connection charging arrangements require NIE to make connection offers that limit charges to one voltage level up. This means that customers that connect new or additional demand to the LV network cannot be charged for 33kV reinforcement. Similarly customers that connect new or additional demand to the 11kV network cannot be charged for transmission reinforcement.

Smaller prospective customers may accept the connection charges associated with an LV connection and possibly even for 11kV assets needed to make the connection. However the consequences of this are that:

- the network will become loaded above firm relatively quickly; and secondly
- the distribution network will develop in a piecemeal fashion that will be less than optimmal when the network is reinforced by a new transmission substation in due course.

NIE is strongly of the view that the proposed development is optimum and there is sufficient justification to proceed as soon as possible to address the various loading

issues that are present in the network between Rosebank, Mountpottinger and Knock Main substations.

However, if the Utility Regulator considers it necessary to allow connection applications to be made and to be addressed or to wait until system loading is unacceptably high with the consequential less than optimum distribution development, then we would suggest that this project be moved from Fund 2 to the NIE Pot 3 /Utility Regulator Fund 3 for specific approval by the Utility Regulator before proceeding.

D24 Cookstown 33kV network reinforcement

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Cookstown 33kV system reinforcement				
24	£2,340,000	0%	£0	No explanation provided of reasons for "endemic" load growth. Firm capacity not exceeded (Table on P16 of A2) In current climate of falling demand, specific local increases must be clearly substantiated.

Comments

NIE is concerned that there is a misunderstanding of the risk being addressed as the Utility Regulator's Draft Determination makes reference to p16 of NIE's January 2011 submission as justification of their position. This section of NIE's submission refers solely to the utilisation of NIE's 33/11kV transformers.

The issue, as clearly set out in NIE's submission (January 2011) and subsequent response to further Utility Regulator questions, was not a concern about transformer overloading but a concern that the 33kV network supplying the town of Cookstown was operating at 99% of its firm capacity[9]. This is a critical network supplying almost 20,000 customers in the Cookstown area and with growth in the area forecast to take the network over firm early in RP5, NIE made provision for capital investment in the submission.

Analysis shows the demand[10] at Cookstown having increased by approximately 3.4% since 2010 which is broadly in line with NIE's forecast. Based on this recent peak demand data, the Cookstown 33kV network is now operating at 103% of firm rating. If demand continues to grow at present rates it is predicted that the network will be over firm by 111% for a significant period of the year by the end of RP5.

[9] Based on 2009/10 system load
[10] Based on 2011/12 system load

D25 Roslea 33/11kV Substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Rosela 33/11kV substation				
25	£700,000	0%	£0	This scheme is not required until RP6. Can be targeted for first phase of any smart meter rollout, demand side management programme or smart grid trial.

Comments

Our original submission confirmed that the 11kV network in the border area around Newtownbutler is already operating at statutory limits during normal system configuration and that resupply within NIE's licence standard can only be achieved by dropping 1MW of customer load for the duration of repairs. I.e. the network is already operating overfirm.

Our paper A2 – 33kV Distribution Network said –

> *"The rural villages of Donagh, Roslea, Newtownbutler and Magheraveely are situated in the south east of County Fermanagh, close to the border with the Republic of Ireland. The 11kV network supplying customers in this area is experiencing poor voltage levels under normal system operating conditions. Resupply availability is inadequate at peak load times."*

In aiming to minimise investment requirements in RP5, NIE has already planned to defer part of the necessary investment until year 1 of RP6. However, the investment planned in RP5 includes an element of 11kV line rebuild and reconfiguration of the network at Lisnaskea to provide an interim improvement and will enable 11kV network reinforcement associated with the new substation proposal to be undertaken. This will provide an interim improvement in voltage levels to ensure compliance with statutory regulations.

It is proposed to manage the risk in two stages, the first stage (£700k) being necessary in RP5. Without intervention, and with only marginal increases in demand on any of the 11kV circuits in the area, NIE will be in breach of licence standards.

The Utility Regulator has proposed to manage this issue by targeting the area for the first phase of any smart meter rollout, demand side management programme or smart grid trial. It is not clear to what extent this suggestion has been considered fully in light of the particular issues presented in this area.

In NIE's view this suggestion is impractical both in terms of the load profile and the extent of deficiencies experienced by this network. The load profiles of the 11kV rural circuits in this area are relatively flat and therefore the use of such schemes targeted at peak reduction would have minimal impact on the network issues experienced.

D26 Castlederg Additional 33/11kV Transformer

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Castlederg 33/11kV substation				
26	£1,160,000	0%	£0	No explanation provided of reasons for "endemic" load growth. Firm capacity not exceeded (Table on P16 of A2) In current climate of falling demand, specific local increases must be clearly substantiated.

Comments

The issue, as clearly set out in NIE's submission (January 2011) and subsequent response to further Utility Regulator questions, was not a concern about transformer overloading but the fact that Castlederg is a single 33/11kV transformer substation with limited resupply capacity through the 11kV network.

NIE has previously demonstrated that in the event of an outage on the 33/11kV transformer or 33kV circuit, full resupply to Castlederg is not possible through the 11kV network. Based on recent demand data[11], the peak load is now 162% of firm rating (11kV resupply capability) and is over firm for a significant period of the year.

At present overload is only avoided by dropping 1MW of load for the duration of an outage as permitted by the Licence standards. Consequently, should the existing transformer fail, a significant section of Castlederg town will be off supply until the transformer is repaired or replaced.

[11] 2011/12 winter demand

D31 Dungannon Main – Granville 33kV line reinforcement

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Granville 33kV reinforcement				
31	£310,000	0%	£0	Firm capacity is adequate. Reassess resupply issue to identify if there is a problem when a probabalistic methodology applied. Should be reassessed and included in logging up at end of RP5 if necessary. Local load growth is not justified (exceedingly optimistic assumptions).

Comments

NIE is concerned that there may be a misunderstanding of the risk being addressed, as clearly set out in NIE's submission (January 2011) and subsequent response to further Utility Regulator questions. Moreover, our latest assessment suggests that this risk is actually greater than was indicated in our earlier submission due to voltage issues.

NIE has previously demonstrated that the peak load under N-1 conditions was already at 102% of the thermal rating[12] of the resupplying conductor and firm capacity was not adequate. However, our more recent analysis into the limitation imposed by statutory voltage levels[13] under N-1 conditions now shows the peak demand to already be 138% of firm capacity and over-firm for a significant period of the year.

[12] based on 2009/10 peak demand.
[13] based on 2011/12 peak demand

D33 Gallaghers/Ahoghill 33kV Network Reinforcement

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Gallaghers 33kV reinforcement				
33	£270,000	0%	£0	Firm capacity is adequate. Reassess resupply issue to identify if there is a problem when a probabalistic methodology applied. Should be reassessed and included in logging up at end of RP5 if necessary. Local load growth is not justified (exceedingly optimistic assumptions regarding occupancy of 1400 recently built dwellings and the construction of a further 1700 dwellings in Ahoghill during RP5). New dwellings could be targeted for phase 1 of smart meter roll out

Comments

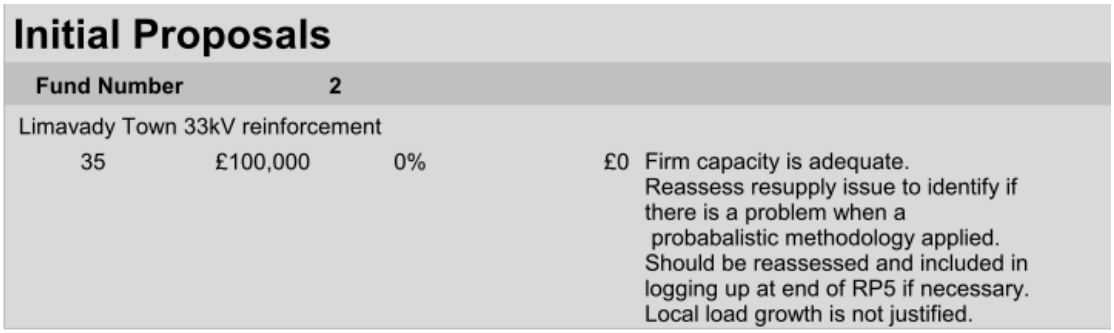
NIE is concerned that there may be a misunderstanding of the risk being addressed, as clearly set out in NIE's submission (January 2011) and subsequent response to further Utility Regulator questions. Moreover, our latest assessment suggests that this risk is actually greater than was indicated in our earlier submission.

The network deficiencies are based on the limited 33kV network firm capacity associated with the 33kV overhead line ring supply Gallaghers and Ahoghill substations going into an overfirm situation with summer loading in 2010. The peak load under N-1 conditions is already at 110% of firm rating and the network is over firm for a considerable percentage of the year (based on 2010/11 system load).

The recently recorded 2012 maximum demand at Ahoghill substation indicates load growth is higher that NIE's 2010 forecast. Demand at Ahoghill substation has increased by almost 3.7% above the 2010 peak demand.

D35 Limavady Town 33kV Line Up-grade

The Utility Regulator Proposal



Initial Proposals

Fund Number	2			
Limavady Town 33kV reinforcement				
35	£100,000	0%	£0	Firm capacity is adequate. Reassess resupply issue to identify if there is a problem when a probabalistic methodology applied. Should be reassessed and included in logging up at end of RP5 if necessary. Local load growth is not justified.

Comments

The network deficiency affects the single 33kV overhead line supplying Limavady Town primary substation which is currently overloaded during periods of peak demand under normal operating conditions.

Limavady town is normally supplied by a single circuit with a changeover system providing resupply. NIE previously stated that this circuit is 92% loaded under normal operating conditions (not resupply conditions) but more recent data taking into consideration the continuous heavy load on the conductor shows that under normal operating conditions, at peak load the circuit is 102% loaded. During Spring and Autumn conditions the loading is 103% of firm capacity under normal system operation. Permanent transfers of load to neighbouring networks are not possible without causing these networks to operate outside firm capacity.

D36 33/11kV Transformer Up-Grades

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
33/11kV Transformers				
36	£4,462,000	12%	£535,440	4 out of 14 allowed (those overloaded in 2010/11) Ballyfodrin, Moypark, Glenavy West, Claudy Central Total cost = £531k = 12%

Comments

The Utility Regulator has reduced provision for this investment from £4,462,000 to £531,000 based on transformer replacement to sites where the firm rating was already exceeded in 2009/10.

An up-to-date review of load against transformer firm rating[14] now shows that the Drumcairne Central and Omagh West substations listed in our submission are already operating above firm capacity indicating that NIE's initial forecast was conservative.

The updated forecast of demand in year 3 of RP5 against transformer rating now shows two further substations listed in our submission as operating above firm capacity, i.e. Poyntzpass and Coleraine West. This forecast also identifies 3 additional sites being overloaded by year 3 of RP5 which were not identified in NIE's original submission.

The two substation sites included in NIE's submission where it was intended replacing the transformers and redeploying the recovered units, i.e. Kilrea Central and Brookhill Central are still forecast as being over firm by 2015/16.

Furthermore there is a misunderstanding by the Utility Regulator of NIE's programme for efficiently managing transformer assets.

The Utility Regulator's Initial Proposal allowance is based on NIE's estimated costs submitted in January 2011 which were calculated assuming redeployment of relatively young transformers from other identified sites in our submission. As these other sites have now been disallowed, the opportunity for transformer redeployment is no longer available. Consequently, the revised estimated cost for undertaking the proposed transformer replacements with new units would be £1,055,000 and not the £531,000 proposed by the Utility Regulator. However, for the avoidance of doubt, all

[14] Based on 2011/12 winter load.

transformers identified by NIE must be changed and not the limited number chosen by the Utility Regulator. It is not acceptable to ignore forecast demand growth.

NIE has already excluded transformers which were forecast to be over firm in the final year of RP5. As it can take up to two years to complete a transformer change from the inception of the project, not allowing investment during RP5 for those transformers which become overloaded in the middle of the period will result in the transformer changes being delayed until the middle of RP6. This will result in a prolonged period of risk to a significant number of customers which is unacceptable to NIE.

Pre-construction expenditure allowances should be made for those transformers that are overfirm loading later in the period. The NIE demand forecast cannot be set aside particularly since it has been shown to be conservative.

D37 11kV Network Load Related Expenditure

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
11kV Load related				
37	£1,740,000	50%	£870,000	50% allowed as the timing of the need has not been justifed, or the factors giving rise to the need explained. This overlaps with the TAR/ Refurb/Re-engineer items, as those totals were not reduced by the km of line being surveyed and upgraded here. Details of schemes requried in the resubmisison.

Comments

This investment is broadly in line with the expenditure levels in RP3 & RP4 of £2.2m and £2m respectively.

Factors giving rise to the investment need have been previously explained as has the fact that all 17 network reinforcement schemes that have been prioritised are required in RP5 to address problematic areas currently identified in the 11kV network risk register.

It is unclear how the Utility Regulator could make the assumption that asset replacement can be considered to be an alternative to 11kV Load related investment. Asset Replacement investment addresses the physical resilience of the 11kV overhead line network; it does not enhance the electrical capacity of the network which is the intent of 11kV load related investment.

While re-engineering does involve upgrade in conductor capacity and therefore provides a load related benefit, there is no overlap between the circuitry being addressed by the re-engineering and 11kV load related programmes in RP5.

Of the seventeen 11kV load related schemes included by NIE in its submission, only 1 of these requires upgrade of 25mm conductor, 8km in total. This proposal (on circuits 24/39 & 55/21 from Dungiven Central & Claudy Central respectively) was not included within NIE's submission for re-engineering. Therefore, it is clear that none of the 11kV load related proposals detailed in paper 1/LR/A3 can be considered to overlap with Refurbishment or Re-engineering programmes and any double counting of TAR expenditure on this single circuit would be de-minimis.

The expenditure level proposed by NIE is based on historical expenditure as previously explained and details of the networks requiring reinforcement have already been provided.

D38 Low Voltage Network Reinforcement

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
LV Load related				
38	£4,840,000	50%	£2,420,000	Overlaps with many other programmes. No historical data or justification of need.

Comments

Notwithstanding the Utility Regulator's comments, NIE has provided the Utility Regulator with historical costs and data and clear evidence of need including:

- the requirements to address voltage complaints arising due to endemic growth on the network[15], based on 5 year average expenditure[16];
- details of 140 network deficiencies in town centre networks; and
- details of 78 transformers that have been categorised as being at risk of overload.

The need for each investment is individually outlined and costed. The expenditure level proposed by NIE is based on historical expenditure levels. The number of complaints has not reduced but conversely is increasing.

The proposed investment of £1.5m for Voltage Complaints was based on the present average annual expenditure of £0.31m. As this expenditure is based on an average requirement and therefore relatively fixed, a broad-brushed 50% cut in overall funding results in a 72% cut in allowance for Town Centre Networks and Overloaded GM Distribution Transformers.

This investment proposal for Town Centre Networks of £2.75m is net of the 40% efficiency gain anticipated by monitoring and reconfiguration and by taking opportunities to carry out works in conjunction with the connection of new large customers or in conjunction with third party schemes. A 72% cut in the investment stream will result in addressing only 16% of the known network deficiencies. This will result in overloading of LV circuits and transformers leading to multiple losses of supplies if fuses rupture due to overload. In addition extra demand increases voltage drop on LV circuits leading to additional voltage complaints and can leave less

[15] The level of expenditure to address voltage complaints has not been affected by the economic downturn implying continued growth in domestic electricity consumption. Expenditure by year: 2007 - £237,648, 2008 - £314,079, 2009 - £373,250, 2010 - £297,939, 2011 - £331,606

[16] Average annual expenditure 2007 to 2011 of £0.31M.

capacity for resupply purposes which is required for substation maintenance and in the event of a fault.

Similarly the investment proposal for Overloaded GM Distribution Transformers of £0.54m is net of 55% efficiency gain through careful load management of the remaining transformers. I.e. it is proposed to upgrade 35 transformers of the 78 transformers presently identified as being at risk of overload. A 72% cut in this investment stream will result in addressing less than 10% of the known transformer overload risks. This will result in continual overload of GM distribution transformers leading to reduced asset life, equipment damage & multiple losses of supplies or even catastrophic failure of this equipment with danger to NIE staff and the public.

There is no overlap between the LV Load Related programme and the proposed programme for undergrounding landlocked networks.

Paper D4, LV Distribution Wood Pole Overhead Lines, proposes investment to underground the following:-

- direct access LV overhead lines where there is a concentration of poles that have a high level of decay (£0.57M investment proposed for undergrounding direct access LV overhead lines).

- landlocked networks (overhead lines and underground cables) which are characterised by routes that extend across significant areas of mature private development i.e. private gardens (£1.68M investment proposed for undergrounding landlocked LV overhead lines).

While the programme to underground direct access LV overhead lines may provide upgrade in capacity and therefore provide a perceived load related benefit, given the low investment level proposed under this programme (£0.57M), there is only a very low probability of overlap between the circuitry being addressed by the undergrounding and the LV load related programmes in RP5.

Therefore, it is very unlikely that the LV load related proposals detailed in paper 1/LR/A4 can be considered to overlap with overhead line asset replacement programmes (TAR, refurbishment or undergrounding of landlocked networks or direct access overhead lines).

D43 ESQCR – Distribution

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
ESQCR - Distribution				
43	£23,000,000	40%	£9,200,000	Fitting of safety signs and anti-climbing devices should be added to unit rates for TAR work (as it will not be possible to accurately report on this seperately). Open to discussion of the impact of this on Fund 1 as part of resubmission. 50% of network alterations approved as risk assessments have not yet been completed. We would need to be satisfied that this is the most cost effective method of risk mitigation before approval of this magnitude of spend could be approved. (total approved for placeholder = £33,658k)

Comments

NIE has been careful to ensure that only those costs which are directly attributable to ESQCR have been included in this request.

As detailed in NIE Strategy Paper F1 – Electricity Safety, Quality and Continuity Regulations, separate programmes for safety signs etc are required to ensure delivery within the timescales.

In determining the extent of remedial works, NIE has targeted the top 10% of high risk poles (approximately 1% of the network).

Approval of only 50% of network alterations on the basis that surveys have not yet been completed is not an appropriate way to proceed. The figure of 50% cannot be defended. The NIE estimate was based on trial patrols and this is the best information available.

Our Strategy paper F1 – ESQCR explained:

> *"Recent trial ESQCR patrols have indicated that:*
>
> - *All LV poles and 65% of the HV poles require safety signs;*
> - *Half of the urban LV overhead network, (which is presently open wire un-insulated conductor) could be accessible from housing or associated structures and provision needs to be made for this extent of network to be protected or altered; and*

- *10% of 11kV and 5% of 33kV poles are high risk with poles and pole mounted transformers in school playgrounds.*

The urban network will be addressed by replacing LV open wire uninsulated conductor with aerial bundled insulated conductor where possible, otherwise diversions or line raising may be required."

The nature of the remedial action proposed by NIE is identical to that adopted by DNOs.

D45 Distribution Capitalised Overheads

The Utility Regulator Proposal

Initial Proposals

Fund Number	4		
Distribution Capitalised Overheads			
45	£23,568,000	0%	£0 to be included in % uplift

Comments

The Utility Regulator has treated this category of expenditure along with the other overhead cost categories;

- T23 Transmission Design & Consultancy
- T41 Transmission Capitalised Overheads
- D12 Distribution Overhead Lines Fixed Costs
- D20 Distribution Design & Consultancy

The Utility Regulator has scaled back these indirect costs on a linear basis to its proposed level of capital expenditure resulting in a determination of 35% of that requested.

This category covers the allocation of overheads associated with cost areas and departments involved in the delivery of capital projects. The proportion of overheads capitalised is based on the activity levels within these areas between work which is capital in nature and that which is revenue in nature.

International Accounting Standard 16 'Property, Plant and Equipment' (IAS 16) states that the cost of an asset will include any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The overheads identified directly relate to capital projects and therefore it is appropriate that these costs are capitalised.

The following cost areas / departments have been identified as being involved in delivering the capital program and therefore it is appropriate that a proportion of the costs associated with these departments is capitalised.

- NIE Powerteam Managed Services / Supply Chain costs. The services provided come under the following main headings – Outage Management, Technical Engineers, Asset Solutions and Safety. Supply chain costs relate to the departments involved in the purchasing of materials & services and the stores and logistics functions.

- Connections department – work carried out by this department includes new connection work, which is capital in nature and recoverable alterations to connections which is treated as R&M.

- Networks department – work carried out by this department includes programmed planning / control, strategic supply chain, metering revenue, contract and asset management associated with both the capital and maintenance programmes.

Technology department – work carried out by this department includes the introduction of new network IT systems which will enhance the efficiency of the business and the maintenance of existing network IT systems. The proportion of overheads which iscapitalised is based on the activity levels within the areas between capex and R&M. In the Utility Regulator's calculations, it has made an error and has omitted to include one of the five classes of indirect costs - the costs associated with distribution design and project management.

Indirect costs can be classified into the 3 separate categories (as defined in Ofgem's RIGs glossary[17]):

- Closely Associated (Engineering) - these costs can be regarded as broadly linear with the quantum of work on the network i.e. the number and complexity of the projects and programmes of work.

- Closely Associated (Other) - these costs are generally non- linear with some costs being generally fixed costs and others subject to step change depending on the size and scope of the work programme.

- Business Support Costs - these costs are not directly or indirectly proportional to the level of investment or quantum of work on the network but support the networks business

Given that indirects can be fixed, variable and step in nature, it is thus not appropriate for the Utility Regulator to apply a general linear scaling back based on the level of capital investment. NIE has calculated that based on the level of capex proposed by the Utility Regulator, the level of indirects in these categories should be more than double what has been proposed. It is not possible for NIE to plan, design and deliver the programme of works within this proposed allowance.

Until a final level of capital investment has been agreed, NIE would request that the Utility Regulator revisits the issue of indirects to arrive at a sensible level based on the specific nature of these costs.

[17] Glossary of Terms - Regulatory Instructions and Guidance: Version 2 - Ref: 75d/11

D48 11kV Network Performance

The Utility Regulator Proposal

Initial Proposals

Fund Number	2		
11kV Network Performance			
48	£9,000,000	0%	£0 no improvement requried

Comments

The NIE submission included a minimum sum that would have permitted network performance improvements for worst served customers by the provision of remote control facilities and fault flow information.

The Utility Regulator's Draft Determination considers that no improvement is required yet DNO customers' who already enjoy better network performance than NIE customers will see further improvements under the DNO investment plans and incentivisation arrangements. Unless there is investment to improve network performance, NIE customers will therefore see network performance deteriorate, relative to GB customers.

The Utility Regulator supports its determination through referring to research into customers attitudes towards standards of service that utilities in Northern Ireland provide. Rather than basing regulatory policy solely on the general body of customer opinion, we would urge the Utility Regulator to consider separately the specific needs of rural customers and the factors that differentiate them from the general body of customer opinion. In this regard, the Utility Regulator and DETI have statutory obligations under the Energy (Northern Ireland) Order 2003[18] to have regard to the interests of individuals residing in rural areas.

The need for NIE's proposed investment is in fact borne out by the conclusions of consumer research that the Utility Regulator undertook in 2010. The research showed that utility consumers in Northern Ireland (both domestic & business consumers) consider the time taken to restore supply and the notice given for planned interruptions as the most important network issue. The research highlighted that any interruption was viewed as having an impact on consumers and the longer the interruption the greater the impact. This research, weighted 72% towards urban

[18] By virtue of article 12(3) of the Energy (Northern Ireland) Order 2003, the Utility Regulator and DETI are required to have regard for the interests of (a) individuals who are disabled or chronically sick; (b) individuals of pensionable age; (c) individuals with low incomes; and (d) individuals residing in rural areas.

consumers and 28% towards rural customers, also emphasised the difference in experiences between rural and urban consumers with rural consumers more likely to have experienced power outages, compared to their urban counterparts. NIE's proposals target a reduction in outage durations for rural customers.

As a result, NIE considers there to be a continued need to improve quality of supply for rural customers. The proposed investment for RP5 will significantly improve quality of service for the customers targeted, as well as allow overall quality of service to keep pace with continuing improvements in GB.

D49 Smart Grid

The Utility Regulators Proposal

Initial Proposals

Fund Number	2		
Smart Grid			
49	£9,350,000	0%	£0 any further specific approvals will be under fund 3. no funding available here

Comments

In deferring expenditure from RP5 into RP6, NIE is dependent on having better monitoring facilities available for high risk age expired equipment. The company is also dependent on the adoption of Smart solutions to reduce investment requirements in the future.

It such equipment is not to be financed, it will not be possible to defer replacement from RP5 into RP6 and future investment requirements will be higher than necessary.

The NIE Strategy paper F5, Smart Technologies, explained how NIE is leveraging benefit by cooperating in consortiums rather than by solely financing research and development.

The paper further identifies areas where Smart technologies will be of benefit to NIE including:

- Dynamic ratings of overhead lines;
- Dynamic Transformer Ratings;
- Demand Side Response;
- Customer Heat Storage;
- Electric Vehicle Charging;
- Carbon Reduction Initiatives;
- Active Network Management;
- Active Voltage Control; and
- On-line Condition Monitoring.

NIE must keep abreast of such developments and engage in pilots to become familiar with the application of the technology.

The approach adopted by NIE is already showing a reduction in capex requirements for RP5 (subject to being allowed the Smart technology finance) and will show further benefits in the future as the technologies mature. Without the funding, NIE will not be able to make progress in the areas listed above.

NIE has taken the application of Smart technology into consideration in the preparation of its submission as follows:

- Some £8 million of transformer replacement is being deferred until RP6 by the adoption of on-line monitoring techniques at a cost of £3 million to manage the risks associated with these deferred replacements.

- The installation of on-line partial discharge monitoring equipment at a cost of £350k will allow deferral of approximately £1 million investment otherwise required to replace 3 circuits.

NIE strongly disagrees with the Utility Regulator's provisional decision to deny funding both for the deployment of Smart technology to offset asset replacement in RP5 and also to develop the techniques for future deployment.

D50 Distribution Substation Flooding

The Utility Regulator Proposal

Distribution Substation Flooding Enforcement				
50	£2,075,000	15%	£311,250	sites with historic flooding allowed Lurgan west Maydown Newry North Newry south sprucefield Other sites do not appear to be within the flood risk areas based on the mapping provided. (simply close to them) More specific information provided at an appropriate scale is required for any logging up to be allowed. (ref to height of flood AOD and substation level AOD to establish need) No site specific costs provided therefore allowance prorata 5 out of 35 =

Comments

In the NIE Strategy Paper, C14 – Primary and Secondary Distribution Substation, Ancillary Systems, the investment requirements were outlined for Flood Mitigation works at Primary Distribution substations. The paper outlined the results of an exercise carried out by an external consultant (Total Flood Solutions) which identified 35 'at risk' sites and proposed mitigations for those sites. Mitigations ranged from permanent flood barriers, to the provision of temporary flood control devices. Total Flood Solutions determined risk and mitigation using available information from the NI Rivers Agency, in line with an electricity industry standard, ETR 138[19]. From the list of 35 'at risk' sites, 15 have been identified as being 'at high risk'. All 35 sites were also reviewed to determine the consequences if they were to be subject to flooding; this led to consequence ratings. The risk rating was combined with the consequence rating to provide an overall risk rating, identifying the 15 most vulnerable sites; these sites were to be addressed under our proposals.

The proposed allowance covers only 3 of the 15 requested sites, i.e. those sites that have already suffered flooding. Therefore under the Utility Regulator's proposals, finance has not been provided for 12 sites that have been identified as 'at high risk' and with high consequence ratings. This is unacceptable and indefensible.

The impact of this decision is significant; 'at high risk' sites have a greater than 1 in 75 chance of a major flood event, based on ETR 138. This event could compromise the substation integrity, potentially causing significant electrical damage. The identified consequence ratings highlight that these sites also supply either large

[19] The Energy Networks Association (ENA) created a task force containing representatives from Industry, BERR, Ofgem, Environment Agencies and the Met Office. Engineering Technical Report (ETR) 138 was produced which identified a systematic approach to ensure the resilience of electricity supplies against flood risk.

numbers of customers, or individual customers who are heavily reliant on a secure supply (e.g. Hospitals and airports).

Given that the overall risk is clearly outlined and the necessary flood mitigation work as recommended in the Total Flood Solutions report, this expenditure is unavoidable.

D55 Network IT

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Non Network IT and Telecoms				
55	£15,275,000	50%	£7,637,500	Concern that the provision of IT services to powerteam via the RAB is a cross-subsidy. This is already included within the capex rates that have been benchmarked and cannot be included twice. Assume that at least 50% of these costs are attributable to power team.

Comments

The Utility Regulator is proposing to allow only 50% of the submission for Non Network Capex on the basis that 'the provision of IT services to Powerteam via the RAB is a cross subsidy'. It is proposed that only £7.638m of the £15.275m submission will be allowed.

£15.054m of the submission relates specifically to IT capex, and £0.221m is associated with other non-network expenditure, including Renewables.

As set out in the NIE opex submission, Powerteam bears its own outsourced IT and Telecoms service charges including desktop, infrastructure, service management and telecoms service charges. However, the non-network capex submission relates to investment required to upgrade or replace NIE T&D IT and Telecoms assets. These are assets which may be utilised by NIE Powerteam employees but only to the extent that they are required to in undertaking activities relating to NIE's T&D business.

As an example, the RP5 submission includes £0.66m investment in the Maximo Asset Management application. This system is used by Powerteam employees to manage maintenance activities and update transformer records on behalf of T&D. However, it would not be appropriate to suggest that this constitutes the provision of an IT service to NIE Powerteam or that any proportion of the costs of upgrading and enhancing the application should be considered a Powerteam cost.

The non-network capex investment included in the NIE submission does not therefore represent the provision of IT services to NIE Powerteam and the Utility Regulator's position on this is erroneous.

On this basis, the full £15.054m of IT non-network capex should be considered as NIE T&D expenditure and therefore allowed.

T6 Transmission Plant Switch house

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Transmission Plant Switch Houses				
6	£2,500,000	90%	£2,250,000	Need accepted. Reporter to verify that scope is delivered. 10% challenge on costs (as costs not benchmarked).

Comments

The Utility Regulator has not provided any reason to establish that NIE's costs would be above a benchmark while all the evidence is that they would be below a benchmark.

T8 Tandragee 110kV Substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Tandragee 110kV Substation				
8	£3,206,000	50%	£1,603,000	Needs to align with implementation of the n-s and renewables develoment. 50% RP5 the remainder RP6.

Comments

NIE Strategy Paper C3 – Castlereagh, Kells and Tandragee, outlines the need to refurbish the 110kV open bus bar meshes at these three sites and describes how this critical work has already been delayed due to the catastrophic failure of oil filled equipment which prevented safe access to the sites.

Kells and Castlereagh 110kV asset replacement has been allowed yet Tandragee, which has the same justification, has been cut to 50% due to an unjustified assertion that it should be aligned with the North South interconnector and renewables development.

Tandragee 110kV substation asset replacement is justified in NIE Strategy Paper C3 as the completion of urgent asset replacement work. The need for similar asset replacement within Kells and Castlereagh 110kV substations, which utilise the same type of equipment of a similar age and condition, outlined in the same strategy paper, was fully accepted.

As previously mentioned, this work has already been delayed due to the catastrophic failure of 110kV equipment on the Tandragee site which prevented safe access. This cause for the delay has now been addressed permitting the replacement to proceed. The need for replacement is based on the poor condition of the existing high voltage equipment and support structures and does not result from the proposed North South Interconnector project.

T10 110kV Switchgear Replacement

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
110kV Switchgear Replacement				
10	£6,350,000	50%	£3,175,000	First phase of work will produce spares that can be used for those defered to RP6

Comments

In the Utility Regulator's response, an assumption has been made that spares recovered from those breakers removed from the system can yield up a sufficient supply of parts necessary to keep the remaining population operating on the system for longer.

The Utility Regulator ignores the fact that NIE has already taken this approach into account when setting the requested numbers. In this category, the least risk option was to replace 20 circuit breakers during RP5 but a higher risk option was chosen. This higher risk option proposes to change only 16 breakers of the initial 20 giving cause for concern and to manage the risk of keeping the remaining 4 operating for a further five years by a more intensive inspection, monitoring and maintenance regime. This approach recognised that 'some spares may be salvaged', considering that 16 breakers may yield up sufficient useable spares for the remaining 4.

The assumption by the Utility Regulator that replacing 50% of the population would yield sufficient spares for the remaining 50% is flawed. This is an approach to asset management that is completely inappropriate in a developed economy. Generally the parts that need replacing, such as turbulators, interrupter heads and porcelains, tend to be the same parts that are affected across the entire population and therefore the majority of recovered spares are not reusable. In addition, manufacturing support is no longer available for this equipment, which makes it impossible to gain certification of primary components once refurbished as the original drawings and technical performance requirements are no longer available.

T11 275kV Plant Ancillaries

The Utility Regulator Proposal

275kV Plant Ancillaries				
11	£5,565,754	47%	£2,615,904	No fault history provided. Individual items from list allowed: Defective catenaries to be replaced at 3 substations - £100,000 50% = Protection replacement at 7 substations - £2,191,500 Asbestos removal at 1 substation - £100,000 Standby generator replacement at 5 substations - £118,330 Transformer bunding at 1 substation - £400,000 DC standby system replacement at 6 substations - £340,184 FMJL & Reyrolle CT replacement (5 of 3-phase sets) at Ballylumford - £264,000 Drainage upgrade at 2 substations - £200,000

Comments

The overall allowance for T11 is 47% of the NIE request. This figure is based on 100% allowances for specific categories as requested, and zero allowances for other categories. Only one category (transformer bunding) has been partially allowed (50%). No allowances have been made for:

- Concrete A-frame refurbishment
- Substation security replacement
- Substation earthing
- Substation ac services
- Drainage

In the above categories, a clear need exists and has been documented in NIE Strategy Paper C2. This work is required to ensure the integrity of the backbone 275kV network, and specific examples highlight the critical nature of this investment:

- Concrete A-frame refurbishment is necessary, as some of these structures are in poor condition, and present both a network and safety risk.
- Substation security. Our 275kV substations are critical components of the commercial and industrial infrastructure of Northern Ireland; some are identified as ‘Key Sites’ under the Centre for Protection of National

Infrastructure. Existing security measures are in disrepair, and have been identified as in need of immediate investment by an external consultant.

- Substation a.c. supplies are critical to the substation infrastructure. This equipment is ageing, and non-compliant when measured against current standards. Given the relatively low value, but high criticality of this equipment, disallowing this spend disproportionately favours cost over risk.

NIE has provided specific and precise information on the need for investment under category T11. Failure to deliver this investment will leave a critical part of the network vulnerable to a range of potential failures, each of which could impact significantly on the network as a whole.

The majority of this work is an integral part of other proposed refurbishment work at transmission sites during RP5 and has been costed accordingly. Failure to approve this work will result in projects not being completed, which will result in costly temporary repairs/modifications needing to be carried out. This will result in a reduced level of equipment performance and costly, inefficient follow up work in the future. In addition, it may not be possible to apply new site ratings until all works have been completed, which will result in an increased number of network operational restrictions.

The level of safety and operational risk implied by the reduced expenditure is unacceptable.

T12 110kV Plant Ancillaries

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
110kV Plant Ancillaries				
12	£7,017,279	47%	£3,298,121	as per 275kV

Comments

There has been no examination of the specific need for investment at 110kV; the supporting information provided by NIE in paper C2 appears not to have been considered. The determination of need for investment in 110kV ancillaries has been made purely on an arbitrary cross-over from the 275kV decision. This approach provides no engineering rationale whatsoever.

As for 275kV Plant Ancillaries, the level of safety and operational risk implied by the reduced expenditure is unacceptable and should not be imposed on NIE.

T13 275/110kV Transformer Replacement

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
275kV/110kV Transformer Replacement				
13	£7,807,575	66%	£5,153,000	Castlereagh and Tandragee allowed No explanation of transition from risk scoring to investment plan provided

Comments

The Draft Determination makes allowances for 2 out of the 3 transformer replacements proposed.

NIE Strategy Paper B1- 275/110kV Transformers, outlines the need to replace three aged 275/110kV interbus transformers during RP5 based on their condition, known degradation based on DGA test results and the long term effects of increased and cyclic loading. The three units prioritised for replacement in RP5 are Castlereagh IBTX1, Tandragee IBTX3 and Coolkeeragh IBTX1.

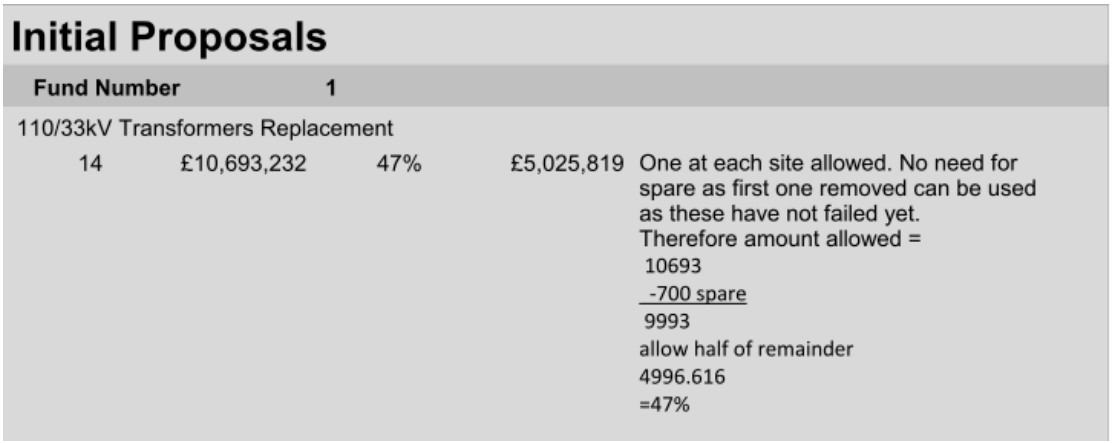
During the review period the Utility Regulator requested NIE oil analysis results for consideration. The results provided clearly demonstrated an increasing trend of gases and other compounds consistent with advanced levels of insulation degradation. The difference in risk scoring between the disallowed Coolkeeragh transformer and the permitted Tandragee transformer is marginal (a difference of 2 in a risk score of 342). However although the Tandragee IBTX3 is the younger transformer, the levels of acetylene (C_2H_2) in the oil have continued to rise which indicates arcing within the main tank. At the time of the submission, the level of C_2H_2 had increased to 47ppm, a level which indicates a serious condition within the main transformer tank with the potential to cause catastrophic failure. The transformer has since been taken off the system due to high acetylene levels and may not return to service.

The tap changer selectors associated with the Coolkeeragh IBTX1 are also continuing to display an increasing gas trend, due to age related degradation. The Coolkeeragh transformer is 4 yrs older and has a higher consequence of failure as its loss would seriously reduce the security of supply to the north west of the province, particularly in the future with high levels of wind generation coming on line.

The Draft Determination would impose an unacceptable level of operational risk and perhaps safety risk on NIE.

T14 110/33kV Transformer Replacement

The Utility Regulator Proposal



Initial Proposals

Fund Number	1			
110/33kV Transformers Replacement				
14	£10,693,232	47%	£5,025,819	One at each site allowed. No need for spare as first one removed can be used as these have not failed yet. Therefore amount allowed = 10693 -700 spare 9993 allow half of remainder 4996.616 =47%

Comments

NIE Strategy Paper B2 - 110/33kV Transformers, outlines the need to replace aged 110/33kV transformers within RP5 based on their condition and known degradation, based on test results. The least risk option for NIE is to replace ten aged transformers, based on their poor condition but it is proposed to change only eight of these ten transformers and to manage the risk of retaining the other two units on the system for a further five years. This strategy would require the purchase of one strategic spare unit and to increase the level of condition monitoring combined with a more intensive programme of maintenance.

Apart from the safety risks of the strategy proposed by the Utility Regulator, it is unrealistic to move transformers of this size, age and condition twice and expect them to operate satisfactorily thereafter. In addition, due to the different types of transformers it would be extremely difficult to install a recovered transformer on another site whilst maintaining safety clearances and oil containment facilities. As the transformers have been highlighted for replacement on condition, they are unfit for reuse otherwise they would not be considered for replacement in the first instance.

Permitting assets to run to failure, as is being suggested for this category, could leave NIE in breach of Licence Standards and legislation, as such failures could be catastrophic in nature and result in injury to staff, contractors or members of the public and extensive damage to the local environment. Customers could also be severely inconvenienced. NIE has experience of the catastrophic failure of major transformers and the consequences could not be deemed acceptable as part of a responsible asset management strategy. Such events are difficult to accept when they are unexpected and would be totally unacceptable as the inevitable outcome of a defined strategy.

Again the Utility Regulator should not consider that it can impose such direct and unacceptable safety and operational risks on NIE.

T15 22kV Reactor Replacement

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
22kV Reactor replacement				
15	£3,669,880	62%	£2,275,326	allow one at each site, and NO spare. = 3* 650k + 3* 105k =62%

Comments

The same safety arguments that were made for 110/33kV transformers failing in service can be made for reactors, as can the argument regarding their successful movement as a strategic spare.

The same unacceptable risks are associated with the Utility Regulator's draft proposals.

T16 Transmission Transformer Refurbishment

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Transmission Transformer Refurbishment				
16	£1,152,000	33%	£380,160	No failure history or detail of condition assessment provided

Comments

The proposed allowance in this category has been cut back to 33% based on there being 'no failure history or detail of condition assessment provided'.

NIE Strategy Paper B6 – Transmission Transformer Refurbishment outlines a requirement to refurbish major transformer components as an alternative to full replacement of the unit, where the main transformer is in acceptable condition. This work is required in conjunction with the proposed replacement programmes to manage the ongoing risk associated with transformer assets.

Strategy Paper B6, provided with NIE's submission, describes in detail the types of failure modes and potential failure modes which have historically affected NIE's transmission transformers and their ancillary systems. The paper further provides a list of those units in each category that currently require attention, based on a detailed assessment.

Appendix 1 within the Strategy Paper describes those techniques used to make the condition assessments and further describes the historic failures and items with a recorded poor condition that have impacted this equipment in the past.

The above assertion does not bear scrutiny nor is the proposed 66% allowance acceptable.

Initial Proposals

Fund Number	1			
275kV Overhead Line Asset Replacement				
17	£8,971,405	43%	£3,857,704	Unit rates for tree cutting required to allow monitoring Suspension insulators = 50% Tension insulators = 100% Spacers = 50% Tower painting = 0% Colour and no. Plates = 20% Foundation assessment = 20% Condition Assessment = 0% (indirect cost) Vegetation = 100% - subject to confirmation of unit cost and volume to be delivered

Comments

The allowances appear arbitrary and are completely unsupported by analysis or justification.

Since NIE is required to comply with statutory obligations and to live with the level of risk it decides is manageable, and based on its own detailed knowledge of assets and the various detailed condition information available to it, NIE completely rejects the Utility Regulator's forecast of the costs required to keep these assets serviceable.

T18 Coolkeeragh – Magherafelt 275kV Overhead Line

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
Coolkeeragh - Magherafelt 275kV Overhead Line Conductor Replacement				
18	£15,000,000	0%	£0	will be assessed with other renewables projects moved to Fund 3

Comments

The Utility Regulator has indicated a 0% allowance but has noted that this asset replacement project will be moved to Fund 3.

T19 110kV Overhead Line Asset Replacement

The Utility Regulator Proposal

Initial Proposals

Fund Number	1			
110kV Overhead Line Asset Replacement				
19	£9,421,468	53%	£4,993,378	Unit rates for tree cutting required to allow monitoring Conductor replacement = 0% Suspension insulators = 50% Tension Dampers = 50% Tension insulators = 0% Tower painting = 0% Pole replacement = 100% Colour and no. Plates = 20% Foundation assessment = 20% Condition Assessment = 0% (indirect cost) Vegetation = 100% - subject to confirmation of unit cost and volume to be delivered

Comments

The proposed allowance implies that the Utility Regulator considers it has better knowledge of NIE's assets however the allowances appear arbitrary and are completely unsupported by analysis or justification.

Since NIE is required to comply with statutory obligations and to live with the level of risk it decides is manageable, and based on its own knowledge of assets and the various detailed condition information available to it, NIE completely rejects the Utility Regulator's prognosis of the costs required to keep these assets serviceable.

The 110kV conductor replacement was for the Dungannon – Drumnakelly circuit (Bonds Bridge – Drumnakelly section). This circuit is key to the reliable export of renewable power from the west of the province but the conductor is in extremely poor condition.

T20 Transmission Cables

The Utility Regulator Proposal

Initial Proposals				
Fund Number	**1**			
Transmission Cables				
20	£4,705,000	33%	£1,552,650	need to prove that the work has a benefit before remaining approved.

Comments

In paper E1 we have set out a strategic and modern approach to the management of our transmission cable infrastructure.

Our expenditure requirements include replacement of the 110kV cables from Castlereagh to Rosebank (2.6km) estimated at £3m which has been justified on the grounds of condition and recent fault history. The benefits of this expenditure include management of unacceptable environmental and network reliability risks.

Repair time for faults on 110kV cables can be of the order of 2 weeks using contractors to supply materials and carry out the work. There is a heightened risk of a fault on the second cable causing a loss of supply in East Belfast, including the new Bombardier factory, and North and Mid Down which would result in cyclic load shedding for a lengthy period of time.

The remainder of our RP5 proposed expenditure was for essential asset life extension schemes including the refurbishment of cable tunnels at Ballylumford Power Station, fluid filled cable refurbishment (including hydraulic systems, fluid replacement and sheath renewal) along with the replacement of ancillary equipment and SVL's.

The level of risk implied by the Utility Regulator proposed allowance is unacceptable.

T23 Transmission Design & Consultancy

The Utility Regulator Proposal

Initial Proposals

Fund Number	2		
Transmission Design and Consultancy			
23	£5,338,879	0%	£0 not allowed, included in % uplift

Comments

This investment category covers the direct cost associated with Transmission substation design and project management of capital projects and for certain projects, the use of specialised substation design consultancy.

The majority of NIE's design capability is in-house and is apportioned directly to the respective capital projects. In addition to NIE's internal design capability, NIE utilises the services of a number of specialised design consultants for production of high level and detailed substation designs.

The investment level proposed for RP5 is based on current RP4 period outturn costs with allowance made for the increased capital programme on transmission substation projects in RP5.

The Utility Regulator has treated this category of expenditure along with the other overhead cost categories;

- T41 Transmission Capitalised Overheads
- D12 Distribution Overhead Lines Fixed Costs
- D20 Distribution Design & Consultancy
- D45 Distribution Capitalised Overheads

The Utility Regulator has scaled back these indirect costs on a linear basis to its proposed level of capital expenditure required resulting in a determination of 35% of that requested. In Utility Regulator's calculations, it has made an error and has omitted to include one of the five classes of indirect costs - the costs associated with distribution design and project management.

Indirect costs can be classified into the 3 separate categories (as defined in Ofgem's RIGs glossary[20])

- Closely Associated (Engineering) - these costs can be regarded as broadly linear with the quantum of work on the network i.e. the number and complexity of the projects and programmes of work.

- Closely Associated (Other) - these costs are generally non- linear with some costs being generally fixed costs and others subject to step change depending on the size and scope of the work programme.

- Business Support Costs - these costs are not directly or indirectly proportional to the level of investment or quantum of work on the network but support the networks business

Given that indirects can be fixed, variable and step in nature, it is thus not appropriate for the Utility Regulator to apply a general linear scaling back based on the level of capital investment. NIE has calculated that based on the level of capex proposed by the Utility Regulator, the level of indirects in these categories should be more than double what has been proposed. It is not possible for NIE to plan, design and deliver the programme of works within this proposed allowance.

Until a final level of capital investment has been agreed, NIE would request that the Utility Regulator revisits the issue of indirects to arrive at a sensible level based the specific nature of these costs.

[20] Glossary of Terms - Regulatory Instructions and Guidance: Version 2 - Ref: 75d/11

T27 Airport Road 110/33kV Substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Airport Road 110/33kV Substation				
27	£3,980,000	50%	£1,990,000	as per distribution project - concern regarding transparent application of connection charging.

Comments

NIE does not accept that the Utility Regulator's proposals will lead to a satisfactory solution to the overloading issues that need to be addressed in the centre and east Belfast networks. Conversely, we believe they will lead to nugatory network expenditure and frustration for connection applicants.

Taking the Utility Regulator's approach NIE would be required to continue adding demand until an application was received that had the potential to "break the camel's back". At that point, irrespective of the size of the demand that applicant would be required to fund all of the deep reinforcement. Clearly, unless the proposed increased demand was associated with a facility that was sufficiently significant to fund the reinforcement this will lead to a major impediment to development within the area. One also needs to be mindful that present connection charging arrangements require NIE to make connection offers that limit charges to one voltage level up. This means that customers that connect new or additional demand to the LV network cannot be charged for 33kV reinforcement. Similarly customers that connect new or additional demand to the 11kV network cannot be charged for transmission reinforcement.

Smaller prospective customers may accept the connection charges associated with an LV connection and possibly even for 11kV assets needed to make the connection. However the consequences of this are that:

- the network will become loaded above firm relatively quickly; and secondly
- the distribution network configuration will develop in a piecemeal fashion that will be less than optimal when the network is reinforced by a new transmission substation in due course.

NIE is strongly of the view that the proposed development is optimum and there is sufficient justification to proceed as soon as possible to address the various loading issues that are present in the network between Rosebank, Mountpottinger and Knock Main substations.

However, if the Utility Regulator considers it necessary to allow connection applications to be made and to be addressed or to wait until system loading is unacceptably high with the consequential less than optimum distribution development, then we would suggest that this project be moved from Fund 2 to the NIE Pot 3 /Utility Regulator Fund 3 for specific approval by the Utility Regulator before proceeding.

T28/29 Ballylumford Eden Carnmoney 110kV Circuit upgrade

The Utility Regulator Proposal

Initial Proposals

Fund Number	2		
Ballylumford - Eden 110kV Circuit Upgrade			
28	£2,310,000	0%	£0 pending technical review regarding need (probabalistic v determenistic)

Initial Proposals

Fund Number	2		
Eden - Carnmoney 110kV Line Upgrade			
29	£2,300,000	0%	£0 pending technical review regarding need (probabalistic v determenistic)

Comments

Two projects are included to upgrade the conductor on the Ballylumford – Eden and Eden - Carnmoney circuits to cater for generation at Ballylumford and the operation of the Moyle Interconnector.

NIE license standards are deterministic. The adoption of a probabilistic standard is not possible in the short to medium term and NIE could not predict what impact the acceptance of such a standard might have on network investment needs or on network availability in the future. No other GB network operator has such a standard in place.

Probabilistic considerations are built in to the existing standards and contingencies such as (n -1) and (n -2) etc. are only considered if they are classed as credible contingencies.

The most serious levels of overload are for the loss of two 275kV circuits (or one 275kV and one 110kV circuit) supplying Ballylumford. The theoretical probability of an n-m-t (a maintenance outage followed by trip) event in reasonable weather is extremely low. Statistically using typical data the probability of an ‘n-dct’ (loss of both circuits of a double circuit tower line) is also quite low. However this contingency occurred several times in a two day period in 2010. During this period three of the four 275kV circuits connecting Ballylumford Power Station were out of service due to the build up of wet snow and wind. Therefore as the event has occurred twice in the last two years, it is therefore a credible contingency. Also post the commissioning of Kilroot Power Station, there were n-dct events on both 275kV double circuit tower lines leaving the station due to salt pollution.

A 2017 study, with the Ballylumford Phase 2 sets retired, examined the loading for the loss of the Hannahstown – Moyle / Ballylumford DCT in winter. The Ballylumford – Eden and Eden – Carnmoney circuits were loaded to 115% and 101% respectively. The operation of the reactive support at Castlereagh can also cause the overloads to get worse.

Apart from the loss of two circuits it is also possible for the Ballylumford – Eden and Eden - Carnmoney circuits to be overloaded under n -1 conditions for all seasons. A sensitivity study based on a 2017 scenario, including the Phase 2 sets at Ballylumford retired and Moyle importing 300MW, a single circuit outage of one of the Ballylumford – Eden or Eden - Carnmoney causes the other to be overloaded. The level of loading ranges from 100% to 113%. Studies show that for an n-1 condition Ballylumford GD would have to constrained off and a 275/110kV IBTX operated open to safely remove the risk of overload.

In autumn with Moyle importing just under 300MW the level of overload for a single circuit outage is 11% again preventing maintenance outage. Any fault outages would immediately result in overload requiring SONI to constrain generation at Ballylumford and or alter the flows on the Moyle Interconnector.

Any increase in the export level of the interconnector with Scotland would require NIE to re-assess the levels of all potential overloads including those on the Ballylumford – Eden, Eden – Carnmoney and Carnmoney – Castlereagh circuits.

T30 Provision of 4th Transformer at Castlereagh

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Provision of a 4th transformer at Castlereagh 275/110kV Grid Substation				
30	£2,169,000	0%	£0	timing uncertain due to decline in demand and n-s interconnector planning process

Comments

A decision was taken in 2008 to order a 4th transformer to be installed at Castlereagh. Castlereagh is expected to require a 4th transformer during RP5 in order to comply with Security standard P2/5. This is due to expected demand growth within the Belfast Harbour area. This project has already been started as part of the RP4 Extension. The transformer raft and a blast wall have been installed with the unit expected to arrive in June 2012.

Demand growth has slowed, however it is still forecast that the transformer will be required in RP5 and NIE still believes the project should proceed early in RP5. It is planned to change out Transformer 1 due to its age and condition. The prior installation of Transformer 4 would ensure that supplies to Belfast will not be at risk during the 7 month outage period required to change Transformer 1.

T31 Armagh Main 110/33kV Substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Armagh Main 110/33kV Substation				
31	£2,000,000	0%	£0	load not currently an issue and rasons for growth not explained or justified. Should be reassessed using probabalistic methodology.

Comments

The NIE submission covered pre-construction costs only. The Utility Regulator's assessment has not recognised this.

The Utility Regulator has ignored the fact that the establishment of a new overhead line 110/33kV substation at Armagh is not a project that can be completed quickly due to planning and consent issues. This project will take at least 6 years from the beginning of the pre-construction phase to project delivery. The refusal of a pre-construction allowance in RP5 means the project would not be delivered until after 2022.

NIE has already stated that the 33kV network that supplies Armagh is currently subject to overfirm loading and voltage problems under single circuit outage conditions (n -1) and the above work is essential to provide load relief on the 33kV network also.

The preparatory work cannot wait until RP6 and must be financed during RP5.

T32 Dungannon Main 2nd 110/33kV substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Dungannon Main 2nd 110/33kV Substation				
32	£2,360,000	0%	£0	Not convinced by the n-2 scenario highlighted here. Reassess using probabalistic methodology.

Comments

NIE proposed the installation of a second 110/33kV substation at Dungannon Main to reduce transformer loading on the existing substation and also ensure that supplies to customers would be secured in accordance with the licence standards for the loss of two transformers.

Normally the probability of a transformer failing during a maintenance outage, or two units in one substation failing at the same time, would be extremely low. However this is a credible contingency which NIE cannot ignore. During December 2011 there was a failure of a tap changer at Drumnakelly Main and the transformer was taken out of service for safety reasons. During this outage there was a serious leak on a 110kV bushing on the remaining transformer. This unit was kept in service however the leak could have resulted in a failure of the bushing and resulted in an n-2 scenario.

Dungannon Main substation falls into category D of the NIE amended P2/5. The standard is based on the assumption that "consideration will be given to rota load shedding to reduce the effect of prolonged outages on consumers" and this would be problematical at Dungannon. There is insufficient capacity in the 33kV network to provide the minimum level of resupply required by Security of Supply Standard.

Dungannon Main supplies a large geographic area that is constrained by the border with ROI to the south and Lough Neagh to the west. Due to the distance and boundaries, the scope for interconnection is very limited. An n-2 outage in this substation would result in a prolonged loss of supply over a very wide area which would be unacceptable.

Both transformers were manufactured in 1974 and are now 38 years old; by the end of RP5 they will be 43 years old and they are very heavily loaded. In the event of a failure of one unit due to the loading there is a higher probability of failure of the second unit.

The need for this investment has been established:

- The transformers are old;
- They are heavily loaded operating at their full rating, there is very little spare capacity;
- Resupply cannot be provided in accordance with the security standard.

The issues that are present create an unacceptable network risk that cannot be ignored.

T33 Castlereagh Knock 110kV Partial Cable Replacement

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Castlereagh - Knock 110kV Partial Cable Replacement				
33	£1,600,000	0%	£0	prefer that whole project is undertaken in one go. Delay until more information about road project or RP6.

Comments

NIE proposes to replace a section of the above duplicate 110kV circuit (from Castlereagh to Braniel Road) in RP5. The fault level at Castlereagh exceeds the 1 second rating of the above cables with the risk that a fault could result in the permanent damage of the entire cable from Castlereagh – Knock. There are also concerns that a fault could cause a catastrophic failure of the cable sealing ends.

One of the reasons to replace the section from Castlereagh to Knock is that it would result in the replacement of the cable sealing ends at Castlereagh. NIE has a concern that in the event of a fault downstream these could fail catastrophically leading to a safety issue. This is an unacceptable risk which cannot be imposed on the company.

The Utility Regulator has disallowed all the costs therefore NIE has no funding to provide the planned double main protection heightening the risks associated with the continued operation of this cable. This is unacceptable.

T34 Tandragee 275kV Substation 2nd Bus Coupler

The Utility Regulator Proposal

Initial Proposals

Fund Number	2		
Tandragee 275kV Substation 2nd Bus Coupler			
34	£1,300,000	0%	£0 delay to coincide with N-S interconnector. ("More resilient" is not an adequate justification for a project)

Comments

Due to concerns raised by SONI regarding the design of the Tandragee 275kV double bus NIE included for the installation of a second busbar coupler.

NIE has concerns at allowing the risk to exist for a further prolonged period of time and the risk of losing 3 interbus transformers remains regardless of whether the second N-S interconnector is in place.

This is an unacceptable risk to NIE.

T36 Belfast North Main 110/33kV Bulk Supply substation

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Belfast North Main 110/33kV Bulk Supply Substation				
36	£680,000	75%	£510,000	project already started - reduction to allow for work completed before the end of the RP4 extension. Note: only costs incurred in RP5 can be logged up/down.

Comments

The Utility Regulator has reduced the allowance against this project to £510k based on the understanding that the project has already started. Whilst the distribution element has started the transmission works will all be incurred in RP5. During the engagement process in January 2012 the Utility Regulator asked "what work has been done and how much will remain until RP5". The Utility Regulator was advised that the carry over to RP5 would be £1.82m, following a general update of costs and scope changes accounting for a review of surge arrestor protection policy and obsolescence of essential protection relays. The UR has incorrectly disregarded these additional costs.

T37 Hannahstown – Lisburn upgrade

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
Hannahstown - Lisburn 110kV Overhead Line Upgrade				
37	£800,000	0%	£0	may be included with the N-S approval, if essential for operation. Not requried before N-S commissioned.

Comments

NIE would accept this approach.

T40 ESQCR – Transmission

The Utility Regulator Proposal

Initial Proposals

Fund Number	2			
ESQCR - Transmission				
40	£2,000,000	0%	£0	not convinced that this is additional above the amounts included in asset repalcement. (No unit rates or deliverables for vegetation included there and allowance included for signs)

Comments

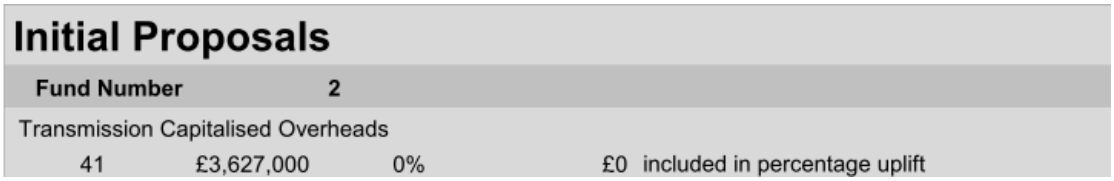
As detailed in paper F1, separate programmes for safety signs etc are required to ensure delivery within the timescales.

Appendix 2 of strategy paper F1 details trial vegetation patrols, carried out in accordance with ETR132. These form the basis of the unit cost/km which contributes to the £1.5m submission for this area of work.

The deliverable for vegetation is km of network compliant with ETR 132 and hence ESQCR.

T41Transmission Capitalised Overheads

The Utility Regulator Proposal



Initial Proposals

Fund Number	2		
Transmission Capitalised Overheads			
41	£3,627,000	0%	£0 included in percentage uplift

Comments

The Utility Regulator has treated this category of expenditure along with the other overhead cost categories;

- T23 Transmission Design & Consultancy
- D12 Distribution Overhead Lines Fixed Costs
- D20 Distribution Design & Consultancy
- D45 Distribution Capitalised Overheads

The Utility Regulator has scaled back these indirect costs on a linear basis to its proposed level of capital expenditure resulting in a determination of 35% of that requested.

This covers the allocation of overheads associated with cost areas and departments involved in the delivery of capital projects. The proportion of overheads capitalised is based on the activity levels within these areas between work which is capital in nature and that which is revenue in nature.

International Accounting Standard 16 'Property, Plant and Equipment' (IAS 16) states that the cost of an asset will include any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The overheads identified directly relate to capital projects and therefore it is appropriate that these costs are capitalised.

The following cost areas / departments have been identified as being involved in delivering the capital program and therefore it is appropriate that a proportion of the costs associated with these departments is capitalised.

NIE Powerteam Managed Services / Supply Chain costs. The services provided come under the following main headings – Outage Management, Technical Engineers, Asset Solutions and Safety. Supply chain costs relate to the departments involved in the purchasing of materials & services and the stores and logistics functions.

Connections department – work carried out by this department includes new connection work, which is capital in nature and recoverable alterations to connections which is treated as R&M.

Networks department – work carried out by this department includes programmed planning / control, strategic supply chain, metering revenue, contract and asset management associated with both the capital and maintenance programmes.

Technology department – work carried out by this department includes the introduction of new network IT systems which will enhance the efficiency of the business and the maintenance of existing network IT systems. The proportion of overheads which iscapitalised is based on the activity levels within the areas between capex and R&M. In the Utility Regulator's calculations, it has made an error and has omitted to include the one out of the five classes of indirect costs - the costs associated with distribution design and project management.

Indirect costs can be classified into the 3 separate categories (as defined in Ofgem's RIGs glossary[21])

- *Closely Associated (Engineering)* - these costs can be regarded as broadly linear with the quantum of work on the network i.e. the number and complexity of the projects and programmes of work.

- *Closely Associated (Other)* - these costs are generally non- linear with some costs being generally fixed costs and others subject to step change depending on the size and scope of the work programme.

- *Business Support Costs* - these costs are not directly or indirectly proportional to the level of investment or quantum of work on the network but support the networks business

Given that indirects can be fixed, variable and step in nature, it is thus not appropriate for the Utility Regulator to apply a general linear scaling back based on the level of capital investment. NIE has calculated that based on the level of capex proposed by the Utility Regulator, the level of indirects in these categories should be more than double what has been proposed. It is not possible for NIE to plan, design and deliver the programme of works within this proposed allowance.

Until a final level of capital investment has been agreed, NIE would request that the Utility Regulator revisits the issue of indirects to arrive at a sensible level based on the specific nature of these costs.

[21] Glossary of Terms - Regulatory Instructions and Guidance: Version 2 - Ref: 75d/11

APPENDIX 4A2

RESILIENCE OF THE 11KV OVERHEAD LINE DISTRIBUTION NETWORK TO EXTREME WEATHER EVENTS

This Appendix contains:

- the covering letter for; and
- the Executive Summary of

NIE's 2nd Draft Consultation Paper dated 2 December 2011 entitled "*The Resilience of the NIE 11kV Overhead Line Distribution Network to Extreme Weather Events*"

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Tanya Wishart
Utility Regulator
Queens House
14 Queen Street
Belfast BT1 6ED

2 December 2011

Dear Tanya

RESILIENCE OF THE 11KV OVERHEAD LINE NETWORK

We have updated our paper - "The Resilience of the NIE Overhead Line Distribution Network to Extreme Weather Events" - in the light of the comments made by the Utility Regulator during our discussions at the meetings on 27 July 2011 and 21 September 2011. A copy is enclosed.

In particular, we have investigated more fully the 'span splitting' option as informed by the outcome of the survey to determine landowners' willingness to have additional poles on their land (which we outlined in our letter dated 13 September 2011). Almost 400 new pole positions have been investigated and the results are discussed in the paper along with our reasons for concluding that span splitting is not a viable option.

The paper examines two other options (increased restoration resources and portable generation), before concluding that rebuilding the 11kV network is the only viable way to mitigate the ice accretion risk.

We have therefore reviewed the costs for rebuilding and revised the figures. Attached to this letter is a table giving the breakdown of the projected cash flows.

[See Note below] Our estimates are based on a unit cost of £ k/km. However, we are aware that the Ofgem figure on an equivalent basis is in excess of £ k/km.

We think that the difference is primarily due to additional construction costs for items such as portable generation but mainly which may be substantial when it is necessary for work to be carried out throughout the year. It is impossible to accurately forecast the range of such costs without having some experience of their magnitude and we are firmly of the view that a pilot is required to establish a more accurate cost estimate including the level of .

A further update to the paper is by way of a section setting out the plans we have in place to cope with a recurrence of an ice accretion event this winter - as discussed with you at the 21 September meeting.

We have also attached a schedule setting out the status of the actions raised at the July meeting. Subject to further engagement with DETI (which we have scheduled for next week), we believe that all the actions on NIE have been discharged.

We would suggest that we meet with you over the next week or so to explain more fully the details and findings of the survey and to clarify any issues arising from your review of our paper and otherwise to discuss the way forward, including as regards consultation with stakeholders.

Yours sincerely

ASHLEY BOGGS

Head of Regulatory Affairs

Note: Unit costs redacted for commercial sensitivity reasons.

Northern Ireland Electricity Limited

RP5 PRICE CONTROL

THE RESILIENCE OF THE NIE 11KV OVERHEAD LINE DISTRIBUTION NETWORK TO EXTREME WEATHER EVENTS

2nd D R A F T

Consultation Paper

2 December 2011

EXECUTIVE SUMMARY

Background and Introduction

Most electricity customers in the rural areas and provincial towns of Northern Ireland depend on the 11kV overhead line network for their electricity supply. It is these customers who are most likely to experience interruptions to their supply as a result of damage to the overhead line network caused by extreme weather. We have developed and refined our capabilities to restore supplies as quickly as possible in such circumstances and this has been acknowledged in the tributes paid to NIE by the Minister, other public representatives and customers. The RP5 price control review provides an opportunity to assess how, in the first instance, damage to the network in extreme weather events - particular those involving ice accretion - can be prevented and how the attendant risk of widespread and prolonged interruptions to customers' supplies can be mitigated.

Following an ice storm in March 2010, an investigation concluded that NIE should liaise with the Met Office to ascertain the probability and frequency of a similar climatic condition occurring again and the probability that such an event could be more widespread. The investigation also noted that the case for developing and expanding the replacement of 25mm^2 conductor would be investigated and proposals would be included in the RP5 capex submission.

NIE's RP5 submission to the Utility Regulator in January 2011 included a paper entitled 'Initial Submission relating to the Resilience of the 11kV Network to Extreme Weather Events'. This follow-up paper considers the likelihood and consequences of such events and presents for consultation possible mitigation programmes and the associated costs.

The Nature of the Problem

Over the last decade severe weather events in Northern Ireland have caused ice accretion on distribution overhead lines with resultant damage to poles and conductors and consequential loss of electricity supply to significant numbers of customers. In particular:

- a snow storm in February 2001 affected the networks in the southern part of Co. Down with a loss of supply to customers for up to 3 days; and

- a more recent snow storm in March 2010 caused significant damage to the overhead networks in the greater Cloghmills area of Co. Antrim with customers being off supply for 6 days.

It is to be noted that both events gave rise to questions not about the condition of the assets but of the ability of the design standard to cope with extreme weather events. In both events it is clear that circuits which are known to have been in good condition, since they had been refurbished (but not rebuilt with heavier conductor), still failed due to design weaknesses.

Furthermore, there was a 'near miss' in December 2010 when a snow storm affected the entire network, but widespread disruption of supply was avoided when the forecast high winds did not materialise.

These events have highlighted the risk of network failure in such adverse weather conditions resulting from the widespread use of small cross section conductor on the 11kV overhead network.

A review of the extent of the risk shows that:

- The use of small cross section conductor during the rural electrification years between 1950s and 1970s was prolific. The 11kV overhead network still has 15,200 km of small cross section conductor in service, approximately 73% of the total network. Of this, some 12,000 km is single phase construction;

- The standards to which the 11kV network was built during the electrification years, and particularly in the post war years when standards were relaxed, are inadequate for the ice accretion weather conditions which were experienced in the two recent snow storms;

- NIE's network is more vulnerable to such events than other UK networks since there is approximately 3.5 times more overhead line per customer than the average Distribution Network Operator (DNO) network and since the DNOs undertook risk mitigation action as recommended by a GB panel of enquiry in 1982 following major storms during the winter of 1980/81. DNOs also have the opportunity to resupply disconnected customers located in hamlets by medium sized diesel generators, an opportunity that is not available to NIE since in a large number of cases customers are supplied by transformers that supply a single property. (NIE has circa 70,000 pole-mounted transformers of various sizes);

- The current asset management policy achieves improvements in network performance but does not provide improved resilience against ice accretion due to the very low lengths of conductor being replaced (on the grounds of being in poor condition);

- Without a change in asset management practice for condition based asset replacement, the ice accretion risk will continue to exist for many decades. Condition based replacement of the overhead line network over the next 10 years will only result in the removal of a small amount of small cross section conductor on main lines and none on spur lines.

Quantification of Risks

Consideration has been given to the likely scale and frequency of extreme weather events in the future and the time required to repair the network following damage by ice accretion and to reconnect customers. Taking the Cloghmills event as a yard stick, it is considered that if the location of this event had been even slightly displaced to a more densely populated area

of a somewhat larger size, the damage and the length of overhead line to be repaired would have been approximately 4 times that of the Cloghmills event. Significantly more damage would have occurred and a much greater number of customers would have been off supply for a longer period of time.

Of particular significance is that even if it were possible to increase restoration resources beyond those employed in the Cloghmills event, the restoration time would have exceeded 10 days, perhaps by a very large margin, and a threshold would have been crossed in terms of customer tolerance and the expectations of customer representatives and other public representatives. The safety and socio-economic consequences of such an event would be extremely serious.

Post the Cloghmills event, NIE has consulted with the Met Office. From this engagement, we have concluded that due to the very specific nature of the accretion conditions (precipitation, temperature, altitude etc) it is impossible to predict in advance its probable occurrence. The work on assessing the likelihood of a more widespread event occurring depends on many assumptions and concludes that the return period for a Cloghmills event may be in excess of 100 years. However this is not substantiated by experience where 2 events and a near miss have occurred in less than a 10 year period and it is clear that the probability of such an event recurring in the short to medium term cannot be ruled out.

The current asset management strategy prioritises network refurbishment based on asset condition assessments and this strategy has resulted in a significant improvement to network performance since privatisation. However, this strategy cannot adequately address the ice accretion risk. This is because overhead line conductors have a long life, usually of the order of 60 to 70 years, and only a small length of condition based conductor replacement and line rebuild has been carried out to date. Although it is recognised in our RP5 submission that the amount of condition based replacement has to increase, the rate proposed would lead to the replacement of 20% of 11kV main line only (spur lines would not be rebuilt) in the next 10 year period and this is insufficient to address the risk discussed in this paper.

Risk Mitigation Options

A change of asset management strategy is therefore required and four options were considered:

- The ramp up of additional external resources to guarantee restoration of supply in less than 10 days;
- The use of portable generation to quickly restore supplies;
- Shortening span lengths on the 25mm2 network to reduce the ice loading on conductors and poles; and
- Rebuilding the 25mm2 network to present day standards.

Neither of the first two options was considered viable. Logistics invariably restrict the rate of restoration and the use of portable generation is not practical due to the very large number of generators that would be required and the connection and fuelling issues that would arise.

The third option for strengthening the network by shortening long spans was investigated but was found to be impractical. Approximately 97,500 spans (approximately half the network) would have to be shortened by the addition of intermediate poles and these would be located in fields rather than in hedgerows (commonly referred to as 'poles out'). A survey indicated that only one third of wayleaves for these poles would be forthcoming on non arable land on high ground but 92% of wayleaves necessary on arable ground were refused. The survey was carried out in the greater Cloghmills area where it was thought that the recent experience of a prolonged loss of electricity supply would have made the proposal more acceptable but opposition to the placing of additional poles in fields was exceptionally strong.

The largest percentage of agreements was obtained on non-arable ground and although there are significant areas of such ground in Northern Ireland particularly around the Sperrin and Mourne mountains and the Antrim plateau, the higher ground is unpopulated and is void of lines. By far the greatest percentage of the overhead line network is on arable land and, on a province wide basis, it would be expected that some 90% of wayleaves for additional poles out would be refused. Since other areas across the province have not had a prolonged loss of supply for some time, the number of refusals may be higher.

Where wayleaves were agreed, these are for isolated spans and span splitting of these with the network on either side being rebuilt would be neither practical nor economic.

As well as being impractical, such an approach would present a lost opportunity to redevelop the existing network to modern standards, which in comparison with other options, would leave a legacy of poorer network performance, higher maintenance requirements and troublesome landowner issues over the lifetime of this investment because of the every significant increase in the number of poles on the network. In addition, this option would still require the network to be reconductored in the medium term due to the deteriorating condition of the conductor.

The preferred course of action is the commencement of a programme to rebuild the 25mm^2 overhead line network to current standards and consideration was therefore given to the optimum pace of rebuilding. A 10 year programme would incur an additional cost of £212m during RP5 and would be difficult to resource whereas with a 15 year programme the additional cost would be reduced to £127m, the increase in resources required would be manageable, the risk would be considerably reduced after 10 years and some reconsideration could be given to asset management priorities at that time.

Although estimated costs have been established, some assumptions have been made and it is considered that a rebuilding pilot should be carried out to establish confidence in unit costs, to allow logistics to be developed and to assess the impact on network performance in terms of pre arranged Customer Minutes Lost.

A further question as to whether the opportunity to future proof the 11kV rural network by rebuilding single phase lines as three phase lines at an additional cost of approximately £6m during the period is raised for consultation. Such future proofing would facilitate the connection of small scale renewable generation to the rural network and provide secondary benefits such as reduced voltage regulation, increased load carrying capability and the opportunity to create further interconnection with automatic restoration of supply possibilities.

Contingency Planning

Although rebuilding of the network will mitigate the risk of ice accretion in the medium to long term, in order to be as best prepared as possible for the incoming winter, NIE has, inter alia:

- increased its spares holdings;
- made arrangements to have increased resources available during emergencies;
- updated its emergency plan to incorporate the importance of involving District Councils and local services;
- reviewed its Critical Care Register in conjunction with the Consumer Council, the Utility Regulator and the Health Trusts;
- reviewed, updated and developed the NIE web site in relation to proactive customer communications, rota load shedding and social media;
- carried out a review of the hosting capabilities of the existing web servers to determine the developments necessary to increase traffic; and
- reviewed and updated contracts for the provision and supply of four wheel drive vehicles and helicopters.

Consultation Issues

Stakeholders are invited to engage to consider the risks and mitigation proposals set out in this paper. In particular:

- Q1 Is it accepted that restoration times following an extreme weather event should not exceed 1 week if possible and that periods of 10 days or more are unacceptable? NIE believes this to be the case.
- Q2 Should the small cross section conductor 11kV overhead line be replaced with line built to modern design standards to significantly reduce the risk of unacceptable network restoration times following an extreme weather event? NIE considers this to be the only viable course of action.
- Q3 At what pace should the risk be addressed? NIE believes that we should aim for a 15 year programme subject to a strategy review after 10 years.

- Q4 In carrying out this network rebuilding programme, should the opportunity be taken to future proof the network? NIE is of the opinion that selected single phase spurs should be rebuilt as three phase to allow for the future connection of small scale renewable generation.

Stakeholders should forward comments to the Utility Regulator before [*date*] and should be addressed to [*xxx].*

APPENDIX 4A3

REAL PRICE EFFECTS

APPENDIX 4A3 – REAL PRICE EFFECTS

1. INTRODUCTION

1.1 In the RP5 BPQ submission (Ref BPQ09 11/2/11), NIE anticipated that it would face significant upward cost pressures on the inputs to its business. NIE argued that such an increase would be over and above any effect already captured by the RPI, and consequently an explicit additional allowance would be needed. NIE found these 'real price effects' (RPEs) to affect:

- the wages that it pays to its workforce;
- the rates charged by its contractors; and
- the cost of raw materials.

1.2 Therefore, NIE calculated the allowances that it would require during RP5, based on the available information about anticipated input price inflation.

1.3 To ensure these effects are accounted for in the regulatory determination, RPE allowances need to reflect the latest RPI, earnings and raw materials cost forecasts.

1.4 Therefore, this Appendix provides an update to RPE indices and allowances for labour and raw materials, based on the latest available official forecasts and evidence. It follows the original BPQ submission in February 2011 and its subsequent November 2011 update (for materials only).

2. SUMMARY OF BPQ SUBMISSION

2.1 In the RP5 BPQ submission, NIE calculated indicative RPEs factors for general and specialist labour. Based on the information relied upon by Ofgem at DPCR5 we assumed that general labour costs would grow 1.4% per annum faster than RPI, while specialist labour costs may grow by 2.1% per annum in real terms. The price for raw materials was found to grow at about 0.6% per annum in real terms.

2.2 The following table sets out the RPEs that NIE calculated at the time of its BPQ submission. Given that contractors supply a mixture of specialist labour, general labour and materials, for simplicity NIE calculated the indicative RPEs for contractors by taking an unweighted average of the RPEs for specialist labour, general labour and materials.

Table 1: NIE's forecasted RPEs at the time of BPQ submission

%	2012/13	2013/14	2014/15	2015/16	2016/17
Specialist labour	2.1%	2.1%	2.1%	2.1%	2.1%
General labour	1.4%	1.4%	1.4%	1.4%	1.4%
Materials	0.7%	0.6%	0.6%	0.6%	0.6%
Contractors	1.4%	1.4%	1.4%	1.4%	1.4%

2.3 The table below shows the input weights that NIE used to calculate RPEs allowances. NIE has a highly skilled workforce which has been provided with substantial bespoke training. Most roles cannot be filled from the general labour force without putting suitably qualified individuals through the same lengthy and costly specialised training programme. Therefore, NIE has a high input weight on specialist labour reflecting the make-up of its workforce.

Table 2: NIE's input weights for BPQ submission

	BAU capex	BAU opex
Specialist labour	25.9%	68.3%
General labour	6.9%	18.2%
Materials	45.1%	7.2%
Contractors	22.1%	6.3%

2.4 NIE used these input weights to calculate the RPE allowances for BAU capex and BAU opex. As the capex and opex figures are expressed in 2009/10 prices, and the RPEs presented above only measure the input price increases over and above RPI, the resulting RPE allowances were also already expressed in 2009/10 prices and required no further adjustment.

2.5 In the BPQ submission, the total requested RPE allowance for BAU capex was £38.2 million over RP5 and the total requested RPE allowance for BAU opex was £10.4 million over RP5.

2.6 Out of this amount, NIE calculated the RPE allowance for raw materials to be £6.9 million for capex and £0.2 million for opex.

2.7 In November 2011 NIE submitted an update to its RPE BPQ submission. The paper presented new evidence on the upward pressure on commodity prices, alongside the

findings of a study by First Economics[1]. NIE found the First Economics' RPE forecasts to be a reasonable basis for forecasting the RPE effect during RP5.

2.8 On this basis, NIE calculated that the updated RPE allowance for raw materials would be £44.1 million. It is estimated that this is split 91.5% capex (£40.4 million): 8.5% opex (£3.7 million). As noted above, these values are expressed in 2009/10 prices.

3. UPDATED RPE INDICES

3.1 To ensure that real price effects are accounted for in the regulatory determination, RPE allowances need to reflect the latest RPI and input price forecasts. In this section, using the latest available information, we calculate updated RPE indices for all the key input factors.

RPI

3.2 Since the BPQ submission, new RPI forecasts have become available. The table below shows the March 2012 forecast from the Office for Budget Responsibility and compares it with the RPI forecast used by First Economics in its June 2011 analysis. As shown in the table, inflation is now expected to be slightly lower in the earlier years of the RP5 period, but higher in 2016/17.

Table 3: Old and new RPI forecasts

	2012/13	2013/14	2014/15	2015/16	2016/17
OBR March 2012 forecast	2.9%	2.3%	2.9%	3.8%	4.0%
June 2011 forecast (First Economics)	3.4%	3.5%	3.6%	3.8%	3.2%

Labour RPEs

3.3 The Office for Budget Responsibility has also made available new forecasts for average earnings growth rates. These are summarised in the table below. Using this forecast, together with the latest RPI figures, an update to the general labour RPEs estimation can be calculated.

[1] First Economics' June 2011 paper prepared for the Scottish Power Transmission RIIO T1 Business Plan, 'Real Price Effects'

Table 4: March 2012 average earnings growth rates

	2012/13	2013/14	2014/15	2015/16	2016/17
Average earnings	2.4%	3.5%	4.4%	4.5%	4.6%
RPI	2.9%	2.3%	2.9%	3.8%	4.0%

3.4 As discussed above, we anticipate that specialist labour earnings will increase at a faster rate than general labour earnings during RP5. To capture this, in 2009 Ofgem used a wage premium of 0.7 percentage points above general labour for DPCR5.

3.5 In 2011, First Economics[2] examined the latest available evidence on specialist labour salary premiums. It found that a 1.25 percentage point premium (rather than 0.7) would be more appropriate. Transmission network owners used this result as part of their RPE submission for RIIO-T1, and this appears to form the basis on which allowances have been set for Scottish Power's transmission network.

3.6 The RPEs for specialist labour can be obtained by applying this premium to the updated inflation forecasts presented above. The following table summarises the implied RPEs for both general and specialist labour.

Table 5: Updated RPEs for general and specialist labour

	2012/13	2013/14	2014/15	2015/16	2016/17
General labour	-0.5%	1.2%	1.5%	0.7%	0.6%
Specialist labour	0.7%	2.4%	2.6%	1.9%	1.7%

3.7 As shown in the table, the RPEs for general labour are positive in each year apart from 2012/13. On average, general labour costs are now expected to grow in real terms by 0.7% per annum. Specialist labour RPEs are positive in each year covered by RP5. On average, they would grow about 1.9% per annum faster than RPI.

3.8 Labour cost RPEs allowances are needed due to the global high demand for specialist labour, compounded by an increasing shortage of the required power engineering skills. A more detailed explanation of the rationale for labour cost RPEs together with detailed supporting evidence are provided in the 'NIE Labour Costs – Real Price Effects in RP5' paper that NIE has submitted separately to the Utility Regulator.

[2] First Economics, *ibid.*

Raw materials RPEs

3.9 As discussed above, NIE updated its estimation of raw materials RPEs in November 2011. The calculation was based on First Economics' findings on expected price inflation for electrical materials.

3.10 It is therefore now possible to update the raw materials RPEs by applying the latest RPI forecasts presented above. These are summarised in the following table.

Table 6: Updated raw materials RPEs

	2012/13	2013/14	2014/15	2015/16	2016/17
Electrical materials price inflation forecast (First Economics)	5.0%	5.0%	5.0%	5.0%	5.0%
RPI	2.9%	2.3%	2.9%	3.8%	4.0%
Raw materials RPE	2.0%	2.6%	2.0%	1.2%	1.0%

3.11 As shown in the table, raw materials RPEs are expected to be positive in each of the years covered by RP5.

3.12 Further evidence supporting the case for applying raw materials RPEs is provided in NIE's November 2011 submission.

4. SUMMARY

4.1 The following table summarises the updated RPE indices across all four categories of input factors. These can then be applied to BAU capex and opex allowances to calculate the updated RPE allowances for RP5.

Table 7: Updated RPE indices

%	2012/13	2013/14	2014/15	2015/16	2016/17
Specialist labour	0.7%	2.4%	2.6%	1.9%	1.7%
General labour	-0.5%	1.2%	1.5%	0.7%	0.6%
Materials	2.0%	2.6%	2.0%	1.2%	1.0%
Contractors	0.1%	1.8%	2.0%	1.3%	1.2%

New RPE allowances

4.2 Since its BPQ submission, NIE has updated the calculation of the share of BAU opex and capex accounted for by specialist and general labour to better reflect the current structure of NIE's workforce. Further details on NIE's current workforce structure are provided in the separate 'NIE Labour Costs – Real Price Effects in RP5' paper referred to above.

4.3 As a result, the input weights needed to calculate RPE allowances have been updated, as summarised in the following table.

Table 8: Updated input weights to reflect NIE's current workforce structure

	BAU capex	BAU opex
Specialist labour	27.2%	71.8%
General labour	5.6%	14.7%
Materials	45.1%	7.2%
Contractors	22.1%	6.3%

4.4 We have used the latest input weights to calculate the updated RPE allowances. On this basis, the total updated RPE allowance for BAU capex is now £58.1m over RP5, while the total RPE allowance for BAU opex is £8.7m over the same period. These results are summarised in the table below, which also provides a breakdown of total RPE allowances into their components. All figures are expressed in 2009/10 prices.

Table 9: Updated RPE allowances

Input	**Capex**	**Opex**	**Total**
Specialist labour	£9.6m	£4.2m	£13.8m
General labour	£0.6m	£0.3m	£0.9m
Materials	£42.8m	£4.0m	£46.8m
Contractors	£5.1m	£0.2m	£5.4m
Total	**£58.1m**	**£8.7m**	**£66.8m**

APPENDIX 7A1

PENSION SURPLUSES IN THE 1990S

Northern Ireland Electricity Pension Scheme
Date: 12 June 2012
Prepared for: NIE
Prepared by: Keith Lelliott

Pension surpluses in the 1990s

Introduction

The Utility Regulator released its Draft Determination for NIE's next Transmission and Distribution Price Control period (RP5) on 19 April 2012 for consultation.

Section 11 of the Draft Determination sets out the Utility Regulator's considerations and "minded to position" as regards the allowance for pension costs for RP5. Paragraphs 11.62 to 11.70 cover the assessment and proposed treatment of benefit improvements and early retirement costs met from pension scheme surpluses during the 1990s and falling in RP1 to RP3.

Addressee

This paper is addressed to Northern Ireland Electricity, the Principal Employer for the Northern Ireland Electricity Pension Scheme (NIEPS).

Purpose

As requested, this paper describes the economic background that led to actuarial valuations in the 1990s typically reporting surpluses, how employers and trustees within the recently privatised electricity industry dealt with these surpluses, and how Ofgem has treated the resulting benefit improvements in setting pension allowances for regulatory purposes in the UK.

Pension arrangements at privatisation

The electricity industries in England & Wales, and Scotland, were privatised in March 1990 with transmission and distribution businesses regulated by Ofgem.

All regulated electricity utilities in England & Wales participate in the Electricity Supply Pension Scheme (ESPS). This is a segregated scheme with separate sections established at privatisation for the regional electricity boards, the successor companies to the Central Electricity Generating Board and other associated companies. Although ESPS has a central overarching trust, in all material respects each section operates with its own set of trustees, adopts its own investment strategy and is recognised as a separate pension scheme under pensions legislation.

In Scotland there are separate pension schemes for the two companies created at privatisation (Scottish Power and Scottish Hydro).

The electricity industry in Northern Ireland was privatised in 1993 and is regulated by the Utility Regulator. Generation was hived off at privatisation and new pension schemes established for the companies so created. NIEPS remained with Northern Ireland Electricity and included

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all pensioners and deferred pensioners at privatisation.

Prior to privatisation, pension schemes within the nationalised electricity industry were typically modelled on public sector arrangements, providing a 1/80th pension, a separate 3/80th retirement lump, and 50% spouse's pension.

Following negotiations between government and unions, pensions for both past and future service were protected under the Protected Persons Regulations for each legal jurisdiction.

Valuations in the 1990s

ESPS (all sections) had actuarial valuations on a 3 year cycle through the 1990s, the first such valuation after privatisation being as at 31 March 1992. Each valuation through to, and including, 31 March 2001 disclosed funding surpluses.

NIEPS was in surplus at privatisation and the actuarial valuation as at 31 March 1991 included benefit improvements agreed with government (the Department of Economic Development) in connection with the privatisation of the electricity industry.

Subsequent valuations carried out as at 30 September 1993, 31 March 1997 and 31 March 2000 all disclosed funding surpluses.

Reasons for surplus

The primary reasons for the surpluses that emerged at consecutive valuations in the 1990s were:

- Strong investment performance, particularly from return seeking assets (mainly equities and property). For example, the annual return on the FTSE All Share Total Return Index over the 8 years from 31 March 1992 to 31 March 2000 was 17.2% pa, and over the same period the average return for pensions schemes (CAPS median) was 14.9% pa
- Low inflation and its impact on pension and pay increases. For example, over the same 8 years, the average rate of RPI inflation was 2.6% pa.

The impact of the strong and relatively stable UK economy in the 1990s, with relatively low inflation and borrowing costs, saw significant levels of surplus being disclosed in UK pension schemes. Such surpluses more than covered increases in liabilities attributable to increased life expectancies, the extent of which were only just coming to the fore within the actuarial profession at the start of the 2000s. Indeed, by the end of the 1990s employers with mature pension schemes and a declining workforce (such as the privatised utilities) were expressing concerns about surplus becoming stranded within their pension schemes due to restrictive legislation on refunds to the employer. There was also active encouragement from government to keep surpluses under control given that pensions schemes were exempt from tax on investments.

Background to use of surplus

Within the recently privatised electricity industry, the unionised workforce still had considerable negotiating power and representation. At the same time employers were under pressure to improve operational efficiency by reducing manpower levels.

This created two pressures for the pension scheme:-

(i) Cost of funding early retirement costs

The pension schemes of the privatised electricity industry include provisions for unreduced early retirement benefits on redundancy. In addition custom and practice from pre-privatisation included the award of additional service as compensation for not working though to normal pension age. As a consequence, redundancies to improve long term operational efficiency had material cost implications from a pensions perspective.

(ii) Pressure to improve benefits

At that time, the public sector benefit structure that typified the pension provisions of the electricity industry at privatisation was seen as poor relative to private sector provision in the following respects:

- 1/80th accrual with a separate 3/80th lump sum was lower than the typical 1/60th accrual (with an option to commute pension);
- Spouse's pension at 50% of 1/80th accrual was low relative to a more typical 50% or 2/3rds of 1/60th accrual;
- Death in service benefits were relatively poor.

Sharing of surplus

As a general belief within the UK economy, employers regarded the surplus reported at valuations in the 1990s as distributable; funding bases were considered prudent, providing a buffer against adverse experience.

Within the electricity industry there were demands for benefit improvements from unions and trustees, alongside employers' intentions to reduce pension contributions.

Bearing in mind a desire to use surplus efficiently to achieve commercial objectives, negotiations recognised that surplus should be distributed between employers and members broadly in proportion to the standard contribution rates of employer (12% of salaries) and employees (6% of salaries) that had been paid, namely 2:1.

Employers within the electricity industry typically used their "share" of surplus to meet the costs of early retirement programmes (leading to lower operational costs in current and future price control periods) and to reduce ongoing employer contributions. Initially ongoing employer contributions were typically held at the standard rate of 12% of salaries, but as concerns about stranded surplus emerged and early retirement programmes were coming to an end, employers also considered taking a full contribution holiday.

As regards benefit improvements, trustees were keen to see surplus distributed fairly across all benefit categories, and not just to current contributing members. Benefit improvements were therefore wide ranging and different across the different privatised utilities and included special increases to existing pensioners and deferred pensioners, as well as addressing the main areas of interest discussed above.

The benefit improvements and employer contribution reductions applied to NIEPS in the 1990s were agreed having regard to practice within the industry generally and followed the same principles and objectives.

Ofgem treatment

For the employers it regulates, Ofgem has recognised that benefit improvements met from surplus disclosed at actuarial valuations in the 1990s are an established part of the employer's ongoing pension costs.

To draw a line under this, Ofgem updated its pension principles for DPCR4 and has put in place the following arrangements:

- Pass through of pension costs, including the impact of future experience, will be limited to the regulatory proportion of past service benefits as at 31 March 2010 for distribution companies and 31 March 2012 for transmission companies ("the established deficit");
- Pension allowances in relation to the established deficit will be spread over 15 years, with adjustment every 3 years to allow for the outcome of future actuarial valuations (subject to an efficiency review to benchmark actuarial assumptions against other regulated energy utilities' pension schemes);
- Allowance will be made for actual contributions being paid at a different pace to the pensions allowance on a "net present value" basis to allow for a faster pace of funding being agreed with trustees;
- The 15 year deficit repair period is set as having a fixed end date, so that adjustments to pension allowances following future valuations will target full funding by the same date, subject to the impact on contributions as that date approaches not being excessive;
- Future service costs will be treated as part of overall employment costs for benchmarking purposes.

APPENDIX 9A1

INCENTIVES AND INNOVATION

NIE'S DETAILED ASSESSMENT OF THE UTILITY REGULATOR'S PROPOSALS

APPENDIX 9A1 – INCENTIVES AND INNOVATION – NIE'S DETAILED ASSESSMENT OF THE UTILITY REGULATOR'S PROPOSALS

1. INTRODUCTION

1.1 This appendix sets out NIE's detailed assessment of the Utility Regulator's proposals for incentives and innovation. It supplements Chapter 9 of our Response.

1.2 Each subsequent section of this appendix is concerned with a particular incentive measure. In order to avoid duplication and/or repetition, this appendix does not address incentive measures in relation to which NIE's case is set out in full elsewhere in this Response.

2. HEALTH & LOAD INDICES

2.1 The Utility Regulator proposes to work with NIE to develop network health and load indices so that "*the implications of any capex over or underspend by NIE T&D are understood*".

2.2 NIE supports the development of network indices in line with regulatory developments in GB and wishes to work collaboratively with the Utility Regulator in their development in Northern Ireland. In that respect, NIE has already commenced the development of health and load indices for the NIE network using the approach established by Ofgem during the last two GB distribution price control periods, DPCR4 and DPCR5.

2.3 However, NIE has significant concerns with the comments[1] made by the Utility Regulator which suggest the use of network indices for incentives. This would be significantly out of step with the approach being adopted by Ofgem, who have been at the forefront of the development of network indices within the electricity industry over an extended period of time.

2.4 Ofgem proposes to use network indices as part of a qualitative assessment at the end of DPCR5, with significant issues needing to be identified before it can be qualitatively determined that a DNO has not satisfactorily delivered its outputs. This is an acknowledgement by Ofgem that:

- only a broad brush approach to the assessment of outputs is appropriate;
- this is not an exact science;

[1] Paragraph 13.62 of the Draft Determination

- these metrics are immature and cannot be used for benchmarking or incentivisation;
- a mechanism for trading outputs has not been established;
- Ofgem cannot and has no desire to micro-manage the business; and
- the principles of RPI-X are sacrosanct.

2.5 These points should also be applied by the Utility Regulator: they are equally applicable in Northern Ireland. However, this will require the Utility Regulator to reconsider its proposed capex model for RP5, which is inconsistent with the points outlined above. Otherwise it is not clear how network indices can be applied in Northern Ireland.

2.6 In contrast, NIE's proposed capex model for RP5 is consistent with these Ofgem principles, which could facilitate the application of network indices once the metrics and processes have been sufficiently developed.

2.7 Moreover, the Utility Regulator implies the development of a mechanism whereby network indices would be used to incentivise individual investments and "*an ex ante level of capex would be agreed as 'at risk' prior to any investment. If standards are not met, then a proportion of capex could be removed from the RAB*".

2.8 Leaving aside the significant issues NIE has with the use of network indices for incentives (as outlined above), it is not immediately clear why the Utility Regulator would consider it necessary to use high level network indices to assess the efficiency of individual investments. Again, this would represent a significant departure from regulatory precedent and would risk the regulator becoming involved in the micro-management of the company's investment programme.

2.9 The rationale for developing network indices in the first instance is to facilitate the regulator in assessing at a high level, the effectiveness of a company's capital investment programme over an extended period of time. This is specifically because it is impractical for the regulator to make such an assessment by bottom up analysis of individual investments. Therefore proposing to use network indices to assess individual investments would appear to confuse their purpose.

3. CONNECTION OF RENEWABLES

NIE proposal

3.1 NIE has proposed incentives for connection of renewable generation to the distribution network in response to DETI's 2020 targets. This recognised that while 750MW of capacity is planned through capex solutions, this will not be sufficient to meet DETI's aspiration which requires 1000MW penetration by 2015. Therefore, NIE proposed an incentive to explore innovative solutions to further extend incrementally this limit of 750MW, for example, through innovative solutions.

NIE response to the Utility Regulator's proposal

3.2 The Utility Regulator makes no reference to NIE's proposal in its Draft Determination, nor makes any reference to providing incentives for NIE to contribute to the delivery of DETI's Strategic Energy Framework. Furthermore, the Utility Regulator has made no provision for funding innovative solutions during RP5, which is out of line with the Ofgem approach. This is further discussed in our comments below on Innovation (Section 9).

3.3 NIE is disappointed that the Utility Regulator makes no reference to NIE's incentive proposal within its Draft Determination. As a result, customers and suppliers have not been made aware of the options proposed by NIE and their potential benefits, and therefore cannot comment fully on the alternative scope of incentives now proposed by the Utility Regulator.

4. NETWORK PERFORMANCE

NIE proposal

4.1 Recent customer survey work carried out by the Utility Regulator's consultants make it clear that customers regard reliability of supply and quick reconnection as a key priority. On this basis, NIE has proposed a network performance scheme for RP5 based on customer interruptions and customer minutes lost (CI and CML) due to unplanned outages on the distribution network. The proposed incentive is symmetrical, with the incentive strength associated with improvements (or reductions) in supply reliability informed by the arrangements in GB, where such a scheme has been established for some time. Annual exposure for NIE and customers would be limited to +/- 1.5% of regulated revenue through a cap and collar mechanism.

NIE response to the Utility Regulator's proposal

4.2 In contrast, the Utility Regulator proposes the introduction of an asymmetric incentive arrangement (penalty only). It is not clear whether the Utility Regulator's proposed incentive arrangement would exclude planned outages

or to what extent NIE's exposure to revenue loss under the scheme would be limited.

4.3 The Utility Regulator's proposals place NIE at a considerable disadvantage to GB DNOs and are unacceptable to NIE. NIE's position on the Utility Regulator's proposals is set out in detail below.

Asymmetric Incentive

4.4 The Utility Regulator refers to its own customer survey but interprets the findings differently to NIE by concluding that the survey supports the Utility Regulator's view that customers are generally satisfied with service levels. This conclusion appears to form the rationale for the Utility Regulator proposing no incentives for improving performance.

Customer Views

4.4.1 NIE would challenge the Utility Regulator's view that customers in Northern Ireland do not value improvements in reliability of supply. Measuring network performance using high-level metrics (CI and CML) reflects the standard of service for the "average NI customer". However, in practice, a range of service levels are experienced across the customer base which is likely to give rise to a similar range of opinion on the merits of seeking service improvements.

4.4.2 Loss of supply is indeed a rare occurrence for the majority of customers, which is recognised in the general satisfaction of customers with service levels they are currently experiencing as expressed in the survey. However this is quite different from suggesting that no more should be done to improve reliability of supply for the smaller proportion of mainly rural customers that currently experience supply outages or are more likely to do so[2]. In common with other customers, it can be assumed that these customers similarly regard supply reliability and quick reconnection as key priorities. All else being equal, improving supply reliability for these customers will also have the effect of improving average network performance (CML and CI). However, the Utility Regulator's proposal suggests that no improvements in service levels for these customers should be encouraged through providing NIE with appropriately designed incentives. NIE does not agree and proposes a symmetrical incentive arrangement that would positively encourage improvements in service standards.

[2] Or reduce the risk of future supply outages affecting customers that hitherto have experienced good performance levels and who to date have been satisfied with service levels.

4.4.3 Furthermore, the Utility Regulator supports its conclusions on Northern Ireland customer views by referencing a survey commissioned by Ofgem on GB customers' willingness to pay for improved network performance that "*also found that customers were generally satisfied with their level of service*".

4.4.4 This does not support the Utility Regulator's proposals for two reasons: firstly, as NIE has demonstrated, there is evidence that some GB DNOs have significantly outperformed on CML in response to the strong incentive measures that have been applied by Ofgem over recent regulatory periods. Therefore, the views of GB customers are largely irrelevant to Northern Ireland as, all else being equal, it is likely that customers in GB will be more satisfied than their counterparts in Northern Ireland with their current level of service. Secondly, despite this level of customer satisfaction in GB, Ofgem has continued to provide GB DNOs with incentives to make further improvements in network performance: the Utility Regulator proposes not to.

Inconsistent with GB precedent

4.4.5 Network performance incentives have been in place in GB for several price control periods which has brought benefits to customers. A properly balanced incentive will enable quality of service for customers in Northern Ireland to keep pace with comparable regions of GB.

4.4.6 Furthermore, in calibrating the penalty that would apply to NIE, the Utility Regulator proposes adopting GB incentive rates (as they apply to SSE Hydro) which are based on willingness of GB customers to pay for a symmetrical incentive arrangement. Therefore the Utility Regulator proposes using GB rates in a manner which is inconsistent with the basis on which they were derived.

Creates imbalance of incentives

4.4.7 Elsewhere[3] in Section 13 of the Draft Determination, the Utility Regulator sets out its objectives for incentivising efficiency, which include encouraging continuous improvement. It is NIE's view that this objective should not be limited to cost efficiency, but should also cover improvements in quality of service.

4.4.8 Incentive mechanisms for performance improvements should be symmetrical and calibrated appropriately with competing incentives for cost efficiency to provide the company with the ability to make

[3] Paragraph 13.18

informed choices that balance cost with the delivery of outputs. Otherwise, the company is incentivised to forego the cost of comparatively low cost improvements and this potentially creates perverse outcomes for customers. NIE's proposals provide this balance; in contrast to those of the Utility Regulator, which provide no incentives for improving network performance.

Presents asymmetric risk for NIE

4.4.9 Annual network performance statistics will exhibit natural fluctuations because of the random nature of network failures and particularly the influence of external factors such as weather and third party interference. Without a symmetrical incentive mechanism, NIE would bear the risk of being penalised for uncontrollable negative outcomes on the one hand but not rewarded for positive ones. This presents an asymmetry of risk for NIE.

Impact of capex reductions on unplanned outages

4.5 The Utility Regulator states that "*NIE T&D would not be offered a payment for improving performance but would be incentivised to maintain it*". However, NIE does not consider the Utility Regulator's wider proposals make adequate provision to enable network performance to be maintained. The Utility Regulator has proposed significant reductions in the capital investment programme proposed by NIE for RP5, which if confirmed, will lead to deterioration in network performance in the medium to long term. It would be unreasonable were NIE to be penalised for not achieving targets that, based on the capex determinations, it may not be able to pursue.

Potential Revenue Losses

4.6 NIE had prudently proposed a "cap and collar" mechanism to limit the extent of potential revenue gains and losses under the network performance incentive scheme to +/-1.5% of regulated revenue. NIE considers both a cap and collar is appropriate for RP5 to reflect the less mature regulatory incentive model in Northern Ireland (and associated uncertainty) compared with what applies in GB.

4.7 While the methodology used by Ofgem at DPCR5 did not establish a cap on rewards available to DNOs for outperforming targets, a collar was established to limit potential losses. This safeguard was retained even though Ofgem and the DNOs already have extensive practical experience of the operation of the mechanism over several regulatory periods.

4.8 As NIE cannot gain from performance improvements, a revenue cap is irrelevant in the context of the Utility Regulator's proposals. However, within

the Draft Determination[4], the Utility Regulator makes no mention of proposing a collar to limit NIE's exposure to potential revenue losses. In the absence of a collar, the Utility Regulator's proposals would expose NIE to greater (unlimited) losses than GB DNOs.

4.9 However, NIE has sought clarification on this point from the Utility Regulator as part of the consultation process and has been advised that the Utility Regulator proposes a cap equivalent to 1.5% of NIE's regulated revenue.

4.10 While this would have the effect of bounding the risk exposure for NIE, significant exposure would remain for NIE due to the asymmetrical[5] nature of the mechanism. As a result, NIE could not balance risk by netting off gains and losses due to variations in performance from one year to the next. This is an unacceptable risk to NIE which is exacerbated by the lack of experience of applying such a scheme in Northern Ireland. This risk to NIE is heightened further by the potential inclusion of planned outages within the incentive scheme, as described below

Inclusion of planned outages within the incentive targets

4.11 NIE has proposed that the network performance incentive scheme for RP5 should be primarily confined to unplanned outages on the distribution network. This is mainly because of the difficulty in accurately modelling the relationship between planned outages and the volume of planned work on the network. As explained to the Utility Regulator in our earlier submission[6], this uncertainty is more pronounced because of the nature of the NIE network as well as the extent of work planned for RP5. Consequently, it would not be prudent to include such forecasting uncertainty in the development of primary incentive targets.

4.12 Within the Draft Determination, the Utility Regulator suggests[7] the inclusion of planned outages within the incentive arrangements. The issues raised by NIE in setting targets for planned outages are not referred to by the Utility Regulator, nor is any reference made to the approach the Utility Regulator plans to take in setting such targets for RP5.

4.13 NIE considers the potential inclusion of planned outages within the incentive arrangement proposed by the Utility Regulator would add significantly to the potential for uncontrollable revenue losses due simply to unavoidable forecasting error. This risk is further increased by the asymmetry of the proposed incentive mechanism; NIE will bear the full risk of systemic losses due to forecasting error but would not have the potential to benefit from

[4] Utility Regulator's Draft Determination paragraphs 13.46 to 13.53.
[5] While NIE has also proposed a 1.5% revenue collar, in contrast with the Utility Regulator, NIE proposes that this downside risk is balanced though a symmetrical incentive mechanism which would also limit potential upside gains to 1.5% of revenue.
[6] NIE's Proposals for RP5 Incentives, section 6.1.1. NIE BPQ Support Paper, February 2011.
[7] Paragraph 13.47

windfall gains in circumstances were forecasting error to be favourable. Such a proposal would be unacceptable to NIE.

4.14 However, NIE has sought clarification on this point from the Utility Regulator as part of the consultation process and has been advised that the Utility Regulator does not intend including planned outages within its proposed incentive mechanism. NIE would support that position if confirmed.

Transmission outages

4.15 NIE has proposed to exclude from the scheme any unplanned supply outages associated with faults on the transmission network and generating plant, because in the first instance these are driven significantly by the performance of third parties (e.g. SONI and generators).

4.16 Also, supply outages caused by such events are relatively rare and where they do occur, there is a relatively wide range of potential outcomes. Therefore were it to become necessary to use a central case assumption for the development of the incentive targets that reflected the range of potential outcomes, it would be likely to produce an outcome whereby actual performance was reflected in either windfall gains or losses simply because of the inability to set robust targets.

4.17 The Utility Regulator does not refer to transmission outages in setting out its position on network performance incentives within the Draft Determination. NIE would welcome confirmation from the Utility Regulator that transmission outages would be excluded.

4.18 Otherwise, the significant exposure already presented to NIE due to the asymmetrical nature of the incentive mechanism and potential inclusion of planned outages (as described above) would be heightened further.

Storm exclusions

4.19 NIE welcomes the Utility Regulator's commitment[8] to work with NIE to agree how severe weather events are dealt with. This methodology should in the first instance be based on the approach for weather events that has been applied by Ofgem over several regulatory periods, tailored as necessary to reflect circumstances specific to Northern Ireland e.g. any particular characteristics of the NIE network or historical differences in regulatory arrangement.

[8] Paragraph 13.53

5. LOSSES

NIE proposal

5.1 NIE has proposed a prudent approach to the introduction of a losses incentive during RP5 reflecting the considerable issues experienced in the operation of the Ofgem ”output-based” losses mechanism in GB, where there has been considerable volatility of outcomes. In light of these issues with an output-based approach, NIE proposes an alternative three-strand approach which involves the following:

- an output-based approach on the distribution network with a tight cap-and-collar (to limit exposure to +/-£0.5 million[9] over the course of RP5);
- an allowance for procuring low loss equipment in RP5 (£1 million); and
- an increased incentive to reduce theft (revenue protection).

5.2 This proposal would incentivise NIE to reduce losses where possible, without exposing NIE and customers to possible windfall gains and losses. It would also incentivise NIE to improve the measurement of losses, which may make it feasible to have a more highly incentivised output-based approach in future price controls.

5.3 In the first instance, NIE proposed to establish the baseline level of distribution network losses over an extended period against which a target could be established subsequently.

NIE response to the Utility Regulator's proposal

5.4 The Utility Regulator recognises the need to obtain historical data and if all measurement systems and reporting structures are in place, proposes to "*set a symmetrical cap and collar for Years 4 and 5 of the control period*" (paragraph 13.36).

5.5 NIE is supportive of this approach and would welcome the opportunity to work with the Utility Regulator during RP5 to establish a viable losses incentive mechanism. We would however reiterate the limitations of an output-based incentive arrangement and the need to ensure any scheme is designed appropriately to reflect the extent of NIE’s ability to influence network losses and the potential impact of measurement error.

5.6 The Utility Regulator has proposed "*a pot of up to £1m over the final two years of RP5*" (paragraph 13.39) to cover:

[9] Note, in describing NIE’s proposals (paragraph 13.38), the Utility Regulator erroneously describes this proposed limit as approximately £0.5 million per year.

- an incentive to reduce losses;
- the cost of buying equipment; and
- costs associated with putting reporting systems in place.

5.7 NIE would welcome discussion with the Utility Regulator on how this fund would operate in practice. For example, this may imply a capped fund of £1 million: if so, it would seem that the allowance for low loss equipment would vary depending on the extent of gains made under the incentive, which would not seem appropriate. In addition, NIE would suggest that allowances for buying low loss equipment and establishing reporting systems should apply from the start of RP5, rather than being limited to the final two years. Clearly, reporting systems should be established in advance of any incentive arrangement coming into operation.

5.8 NIE has concerns about the potentially limited amount of funding for low loss equipment, particularly as this may be reduced by incentive payments and the cost of establishing reporting systems if the overall ”pot” is capped.

6. REVENUE PROTECTION

NIE proposal

6.1 As referred to above under losses incentives, NIE has proposed to strengthen the existing (RP4) incentives to reduce electricity theft (revenue protection), which represents non-technical losses.

6.2 The existing incentive relates only to certain non-domestic vacant premises. The benefit of any monies recovered by NIE under the scheme is currently shared on a 50:50 basis between NIE and customers, with customers funding the cost of operating the scheme. NIE has proposed a change whereby NIE would bear the costs of the scheme and in return would retain in full, any monies recovered for past illegal abstraction. This would provide NIE with a strong incentive to manage the scheme at the appropriate level with the flexibility to operate the scheme to maximise the detection of illegal abstraction. Customers would continue to benefit in full from the prevention of any further illegal abstraction that would otherwise have occurred, and therefore gain from earlier detection. The changes proposed by NIE would therefore benefit both customers and NIE.

6.3 NIE has also proposed extending incentives to detect illegal abstraction at premises other than the non-domestic vacant premises eligible for the current incentive scheme. This would mainly apply to domestic premises. Under this proposal, NIE would also bear the cost of increasing resources to outperform an annual target for units recovered under the scheme. In return, NIE would

be incentivised by receiving an increase in revenue entitlement equivalent for each unit recovered in excess of the target.

NIE response to the Utility Regulator's proposal

6.4 The Utility Regulator recognises that "*the revenue protection unit service provided a net benefit for consumers in RP4*" and proposes "*it should continue in RP5*" (paragraph 13.43). This would imply that the Utility Regulator is proposing no change to the RP4 arrangements.

6.5 NIE does not agree with this approach which is inconsistent with the Utility Regulator's position that NIE should be incentivised to reduce losses. Elsewhere in its Draft Determination[10], the Utility Regulator quotes the aggregate cost of losses to customers and presents this as a cost that NIE can influence, but has no incentive to do so.

6.6 The cost to customers of losses due to illegal abstraction is significant and is something that NIE can influence more directly in the short-term than technical losses (i.e. those losses due to the flow of electricity through the network). Moreover, NIE's proposal would allow recovered losses to be identified clearly and measured at source, without being subject to the systemic issues associated with accurately measuring overall network losses that we refer to in the preceding section. It is therefore surprising that NIE's proposals for strengthening revenue protection incentives have not been adopted within the Utility Regulator's incentive proposals for RP5. The reasons for this omission are unclear as NIE's proposals are not discussed in the Utility Regulator's paper.

6.7 Moreover, NIE is disappointed that the Utility Regulator provides no detail of NIE's revenue protection incentive proposals within the Draft Determination. NIE's proposal is mischaracterised[11] in the Utility Regulator's paper by means of it being linked with a separate and unrelated proposal for additional revenue protection electricians associated with keypad meter reading activity[12]. As a result, customers and suppliers have not been made aware of the options proposed by NIE and their potential benefits, and therefore cannot be expected to comment sensibly on the Utility Regulator's proposals in this regard.

6.8 It should be noted however that if the Utility Regulator remains minded to make no change to the RP4 revenue protection incentive arrangements, then additional provision should be made by the Utility Regulator within the RP5 opex allowance to allow recovery of the costs of £769,000 during RP5 to

[10] Paragraph 13.37
[11] Paragraph 13.42
[12] For clarity, NIE proposals for revenue protection incentives in RP5 are based on it funding any increase in staff or other additional costs it deems necessary to target improved performance.

provide additional revenue protection electricians[13] to meet the needs of keypad meter reading activity. For the avoidance of doubt, these costs are not presently included in NIE's opex submission consistent with the basis of NIE's incentive proposal for RP5.

7. CUSTOMER SERVICE

NIE proposal

7.1 NIE proposed (in February 2011) to engage with the Utility Regulator through the price control process with the aim of developing customer service incentives for RP5. This would take account of the on-going development by Ofgem of similar arrangements for introduction in GB in April 2012.

NIE response to the Utility Regulator's proposal

7.2 The Utility Regulator does not agree that customer service incentives are required based on its view that customers are content with current standards of service. On this basis, the Utility Regulator does not propose incentives to improve customer service. This is not in customers' best interests.

7.3 In contrast, NIE considers that a properly balanced incentive framework with incentives to improve customer service would enable service levels for customers in Northern Ireland to continually improve and keep pace with comparable regions in GB where incentives apply. This was the basis of NIE's proposal.

7.4 While the Utility Regulator proposes changes to Guaranteed Standards (as considered in the following section), these will not provide strong incentives to improve overall quality of service for customers. The purpose of Guaranteed Standards is to provide minimum standards for customers, and to compensate customers for service failures. These are complied with in all but very exceptional cases. Moreover, the proposed changes to Guaranteed Standards relate only to very specific areas of customer service.

8. GUARANTEED STANDARDS

8.1 The Utility Regulator proposes changes to Guaranteed Standards for RP5 including the introduction of three new standards, the tightening of the existing standard for supply restoration, as well as amendments to the rates of payment to customers who claim defaults against existing standards.

8.2 The three new standards proposed by the Utility Regulator relate to: -

[13] RP5 cost - £769,000 . Initial equipment and set-up of £39,000 and annual costs of £146,000 (2009/10 prices). NIE submission 14 October 2011 refers.

- Responding to general complaints;
- Providing a cost estimate for a generator connection; and
- Network performance for ”worst served customers”.

8.3 It is also proposed to tighten the standard for restoring the supply of electricity following a fault from 24 hours to 18 hours.

8.4 The Utility Regulator also proposes to increase payment rates by 60%.

NIE response to the Utility Regulator's proposal

8.5 NIE has considered the findings of the recent customer survey[14] carried out on behalf of the Utility Regulator and notes in particular the conclusion that:

> "*The research points to a strong desire for consistent standards and payments across each of the three utilities where these are applicable, primarily to make it easier for consumers to understand entitlement in various situations.*"

8.6 In Northern Ireland Guaranteed Standards currently only apply in the electricity sector in Northern Ireland, with no similar standards for gas and water utilities. NIE has therefore proposed that standardisation of standards across the utility sector ought to be the first priority, followed later by any enhancements considered appropriate, subject to agreement on costs.

8.7 The rationale put forward by the Utility Regulator for proposing the introduction of new standards for RP5 is that they have reviewed standards in GB and RoI which has highlighted "*some areas where it would be possible to develop or update the standards for NIE T&D*" (paragraph 13.67).

8.8 No evidence is presented by the Utility Regulator of customer demand for the introduction of additional standards or whether any assessment has been carried out by the Utility Regulator of the cost and practicalities of introducing these standards in RP5. Neither have these considerations been discussed with NIE to better inform the Utility Regulator's assessment of what may be possible and what it would cost.

8.9 As would be the practice in GB, additional resources and changes to IT systems should be established in advance of implementing any changes in standards and/or incentive arrangements. Otherwise, NIE will carry the risk that new requirements are put in place at the start of RP5 that are ill-defined and without the systems established to robustly measure performance.

[14] PIMR survey (May 2010), Executive Summary, page 4

Inconsistency in the Utility Regulator's proposals

8.10 NIE recognises fully the need to focus on improving the levels of service received by our worst served customers, who are most likely to be mainly connected to the extremities of the dispersed rural 11kV network. NIE has therefore proposed a modest investment programme (£9 million) for RP5 to improve network performance, most of which involves fitting remote control devices on the rural 11kV overhead line network with the intention of improving the time taken to restore customers' supplies.

8.11 In contrast, the Utility Regulator has made no provision for this investment within its capex proposals on the basis that customers are generally satisfied with current levels of service and therefore, that no improvements are necessary. This is clearly inconsistent with the Utility Regulator's proposal to introduce new guaranteed standards to "*improve the network performance for 'worst served customers' …*"[15]. On the contrary, the Utility Regulator's capex proposals will have the effect of preventing NIE from making network improvements for "worst served customers".

Incentives to improve performance

8.12 NIE considers incentives to be a much more appropriate way of driving performance improvements than introducing new or amended guaranteed standards. In this regard, NIE has considered the case for introducing a strong incentive to improve performance for "worst served customers". However as NIE's control room systems do not currently have the functionality to monitor "worst served customers", NIE has proposed leaving incentives for "worst served customers" until RP6, with the focus during RP5 on measurement and reporting.

Practical considerations

8.13 The most significant practical issue with the Utility Regulator's proposal relates to the proposed introduction in RP5 of a network performance standard for "worst served customers". As referred to above, NIE does not currently have the capability to monitor "worst served customers".

8.14 While NIE plans[16] to upgrade its Network / Trouble Management system (NMS), this will limit functionality for reporting "worst served customers" to those supply outages caused by HV faults.

8.15 It is not clear whether the Utility Regulator is proposing the inclusion of LV faults within the standard. As NIE has already advised the Utility Regulator[17],

[15] Paragraph 13.70
[16] NIE intends specifying the functionality to monitor worst served customers in the proposed upgrade of its Network Management System.
[17] D_REQ136, NIE BPQ submission, February 2011

even with the planned upgrade of its NMS, NIE would not have the functionality to map LV connectivity. Were this functionality required for reporting purposes, this application would need further development not only on the systems side but also with capturing and maintaining LV records. To implement this functionality would cost approximately £2.4 million and it would take at least four years to capture the LV records. Beyond that, a minimum of two years would be needed to monitor performance in order to inform the development of an appropriate standard. Therefore, any ”worst served customers” standard that takes account of LV faults cannot be implemented during RP5.

8.16 In Northern Ireland, the price control arrangements for incentivising and reporting quality of supply are quite different from those in place in GB. The GB arrangements have provided DNOs with considerable capex allowances and strong incentives to encourage improvements over a number of regulatory periods. These regulatory drivers have not been in place in Northern Ireland to date. Furthermore, initiatives in GB to improve the measurement of quality of supply and the calibration of standards reflect the development of quality of supply incentives. It would therefore be wholly inappropriate for the Utility Regulator to simply apply verbatim the GB standard in Northern Ireland without any validation of current performance levels or reporting capability in Northern Ireland.

8.17 It will take at least two years to establish the necessary reporting systems as part of the NMS Upgrade and at least a further two years of monitoring current performance levels before a minimum level of performance could be established in a robust manner. Therefore, it is NIE’s view that October 2016 is the earliest practical date for the introduction of a guaranteed standard for network performance for ”worst served customers”. Even then, this would be limited to performance in respect of HV faults only.

Recovery of additional costs

8.18 In general, NIE considers it unreasonable to introduce new or tighter standards without also providing for the recovery of the costs incurred by NIE in meeting those standards. We set out below NIE’s assessment of the additional costs that will result from the introduction of the new or tighter standards proposed by the Utility Regulator for RP5. We estimate that these proposals will add approximately £1.3 million to NIE’s operating costs during RP5, and depending on their design, require additional capital investment of £2.4 million in RP5.

Responding to general complaints (new)

8.18.1 NIE estimates that this will add approximately £9,000 per annum to operating costs during RP5. These costs relate to administration, monitoring and recording customer contacts.

Providing a cost estimate for a generator connection (new)

8.18.2 NIE estimates that this will add approximately £9,000 per annum to operating costs during RP5. These costs relate to administration and monitoring operations against the new standard.

Network performance for "worst served customers" (new)

8.18.3 If the standard relates to HV faults only, NIE estimates that this will add approximately £9,000 per annum to operating costs during RP5. These costs relate to administration and monitoring operations against the new standard.

8.18.4 If the standard relates to both HV and LV faults, NIE estimates that this would add approximately £51,000 to operating costs in the final year of RP5. These costs relate to maintaining LV connectivity records through on-going survey of the network and update of IT systems. These costs would apply once the initial four-year programme of data capture of LV records was completed (see above). Also, as highlighted in paragraph 8.15, implementing the required functionality would cost approximately £2.4 million in set-up costs.

Restoration of supply in 18 hours (tighter standard)

8.18.5 NIE estimates that this will add approximately £231,000 per annum to operating costs during RP5. These costs relate to additional out-of-hours working and the provision of additional LV generators where required to comply with an 18-hour standard.

Default payment rates

8.18.6 The Utility Regulator proposes to increase current payment rates "*in line with RPI*". In most cases, this will result in default payments increasing from £25 to £40, which is equivalent to a 60% increase.

8.18.7 NIE notes that current rates are already greater than the equivalent payment rates that apply in GB. On this basis, NIE does not consider an increase in rates to be necessary.

9. INNOVATION

9.1 The Utility Regulator's position with respect to innovation is set out in Section 14 of the Draft Determination.

9.2 In RP4, NIE has been proactive in research and development of innovative approaches to improve utilisation of network assets. For RP5, NIE intends to

build upon this experience and increase our efforts to take on more challenging innovation projects. This will include smart technology initiatives that can be applied in the short and long-term to meet the challenges in the design and operation of the network arising from renewable energy resources and the growth of emerging low carbon technologies.

9.3 NIE has sought £14.93 million within RP5 to fund smart technology including:

- £2.5 million for its research and development (R&D) programme;
- £6 million for trialling smart technology projects;
- £3.35 million for applying advanced condition monitoring to network assets; and
- £3.08 million for upgrading its distribution network management system to facilitate smart grids.

9.4 The Utility Regulator has separately approved the upgrade to the distribution network management system outside of the RP5 price control process.

9.5 The Utility Regulator has made no provision, as part of its RP5 proposals, for the remaining three initiatives which form the core of innovation funding sought by NIE for RP5.

9.6 NIE's proposal for R&D (£2.5 million) was included in its opex[18] submission. The Utility Regulator makes no allowance for this within its opex proposal.

9.7 In respect of trialling smart technology projects, the Utility Regulator proposes the inclusion of "new technology trials" as an investment category under its Fund 2 (Table 9.8) but no actual expenditure allowance has been provided within the Fund 2 allowance proposed by the Utility Regulator.

9.8 NIE's objective is not to be a research leader or be at the leading edge in the area of smart technology but to adopt the "fast follower" approach where possible. However, it will not always be possible to incorporate smart technology design that worked elsewhere without considering the feasibility of deployment on the NIE network. Without this funding for R&D and trials, NIE will be unable to assess emerging technologies[19] and participate with collaborative research to factor this into future planning of the NIE network. In contrast, Ofgem has provided GB DNOs with substantial funding[20] to support development of smart technology recognising its importance in stimulating the application of smart technologies.

[18] The Utility Regulator states that 'these funds were requested as part of NIE's capex submission' (paragraph 14.29). This is not correct: funds for R&D were included in NIE's opex submission.
[19] Including electric vehicles, microgeneration, heat pumps etc.
[20] For example the Low Carbon Networks Fund (LCNF) and Innovation Funding Incentive (IFI).

9.9 The Utility Regulator has also made no provision for applying advanced condition monitoring within its capex proposals. The application of this technology (£3.35 million) is intended to facilitate a reduction in asset replacement expenditure during RP5 and this reduction has already been assumed in NIE's capex proposals. The Utility Regulator's proposals are therefore inconsistent. Clearly, provision should be made for either the asset replacement expenditure or the condition monitoring equipment that would otherwise enable the asset replacement expenditure to be deferred. NIE's preference is for the latter, as set out in our capex proposals.

APPENDIX 12A1

NIE'S COST OF CAPITAL AT RP5

NIE's cost of capital at RP5

A REPORT PREPARED FOR NIE AS PART OF ITS RESPONSE TO THE UTILITY REGULATOR'S DRAFT DETERMINATIONS

June 2012

NIE's cost of capital at RP5

NIE's cost of capital at RP5

Executive Summary

In 2011 Frontier Economics was commissioned by NIE to provide a report setting out its view on the appropriate weighted average cost of capital for NIE for the RP5 period. Our final report, dated May 2011, was submitted to the Utility Regulator by NIE.

The Utility Regulator has now published its Draft Determination for RP5. Given that approximately one year has passed since we submitted our last paper, NIE has asked us to provide an updated view on the appropriate cost of capital for NIE for RP5, taking account of recent developments and in particular the Utility Regulator's Draft Determination. This report provides an update to our May 2011 paper.

Methodological approach

As we described in our 2011 report, NIE is one of 15 DNOs in the United Kingdom. Fourteen of these DNOs are regulated by Ofgem, the GB energy regulator. NIE is regulated by the Utility Regulator. This institutional arrangement enables the regulatory agenda to be sensitive to specific local circumstances such as DETI's Strategic Energy Framework for NI. At the same time, it enables the Utility Regulator to incorporate the generic aspects of regulation that also apply to the DNOs in the rest of the UK, an approach which should ensure the NI regulatory framework can be readily understood by investors who are familiar with that which applies to DNOs in the rest of the UK.

On the basis of this institutional setup we developed an approach to determining the cost of capital for NIE for RP5 for our 2011 paper. We still regard this approach to be the right one and we further believe that we can address the majority of the Utility Regulator's proposals within that structure. Consequently we have largely retained that structure for this paper.

- **Stage 1** took Ofgem's decision at DPCR5 as the basis for the Utility Regulator's decision at RP5. This decision needs to reflect not just the headline WACC allowed by Ofgem, but the actual baked-in returns that DNOs were allowed, which are in excess of the baseline WACC.

- **Stage 2** enabled the adjustment of the WACC calculated at Stage 1 to take account of relevant NIE-specific factors.

- **Stage 3** in our original report evaluated whether financial market evidence on the WACC has changed significantly since DPCR5, to such an extent that merits a change to the parameters of Ofgem's decision. In this report we update the analysis we carried out last year to reflect the latest market

evidence. We also evaluate the Utility Regulator's detailed WACC proposals and present an assessment of whether those arguments, or changing evidence, might lead us to change our view.

Note that our first paper for NIE included a fourth stage, in which we assessed the financeability of NIE's business at our proposed cost of capital. We have not considered financeability as part of this update, but we understand that NIE intends to undertake its own analysis in this respect.

The application of this approach should provide clarity to investors that there is a sensible process to determine the WACC for NIE, which takes the settlement for the 14 other UK DNOs as the firm basis for that process; whilst at the same time providing some degree of flexibility for the Utility Regulator and NIE to reflect specific factors that apply to NIE and any significant changes to market conditions.

Implications for the WACC

Following the application of our methodology, including our assessment of the Utility Regulator's proposals, we have drawn a number of conclusions.

- It would be inappropriate to set a WACC below the generic return that Ofgem expects DNOs in the rest of the UK to earn, since this would adversely affect investor sentiment towards NIE at a time when NIE will need to compete with the other UK DNOs (as well as operators from around the world) for finance to fund the large capex programme which is required at RP5.

- Updated benchmarking analysis of NIE's costs continues to show it to be an efficient operator, and allowing it less than the average return allowed by Ofgem would result in a risk profile that would be skewed to the downside, relative to that which applies to the other DNOs in the UK, and would also negatively impact investor sentiment. It would also remove an important incentive to improve continually performance, which ultimately benefits customers.

- In DPCR5 Ofgem allowed a baseline cost of equity allowed of 6.7%, and a RORE for the average GB DNO of 7.7%. This reflects a RORE uplift of 1.0% to the baseline real cost of equity. In our view, therefore, the Utility Regulator should apply this 1.0% uplift to NIE's estimated baseline cost of equity. Early evidence of actual returns achieved by GB DNOs during the first year confirms that all DNOs are earning equity returns significantly above the baseline level, and in many cases significantly above the average uplifted level of 7.7%.

- We continue to support the application of Ofgem's trailing average methodology to determine the appropriate cost of debt. However, since our last report we have become aware of evidence of a sustained premium in the yields of NI utility debt (i.e. bonds issued by NIE and Phoenix Natural Gas) relative to similar debt issued by GB utilities, in particular GB DNOs. On the basis of this evidence, we take the view that the Utility Regulator should apply an NI-specific adjustment to the cost of debt of at least 100 bps (potentially as high as 123 bps).

- The evidence of an NI premium on the cost of debt should also be reflected in the allowed cost of equity, net of any element of this premium that arises as a result of low liquidity. On the basis of the evidence available a further uplift to NI equity returns of between 62 bps and 109 bps is justified. Since this uplift and the RORE uplift are additive, this suggests that the appropriate level for equity returns could be as high as 8.8%.

- We therefore conclude that there is ample evidence that a post-tax real cost of equity of 7.7% as proposed by NIE is more than justified and might be regarded as conservative.

- Finally, the Utility Regulator has proposed a lower allowed cost of capital for Fund 3 investments, implemented through a reduction of 0.1 in the asset beta for such investments. We believe that this approach is flawed as there is no reason to believe that renewables-driven investments are intrinsically less risky than NIE's transmission and distribution assets. Given that the Utility Regulator's proposals for approving renewables-driven investments are consistent with Ofgem's, it should follow GB precedent and allow the same rate of return on renewables-driven investments assets and NIE's transmission and distribution assets.

The table below summarises our estimates for each of the individual parameters, and presents our overall estimate for the WACC (vanilla, real).

Summary of individual parameters and overall WACC estimate

Parameter	Frontier estimate
Risk-free rate	2.0%
ERP	5.25%
Equity beta* (transmission and distribution assets; renewables-driven investments)	0.90
Baseline cost of equity (real)	6.7%
RORE uplift applied to average GB DNO at DPCR5	1.0%
Expected return on equity (post-tax, real)	**7.7%**
Baseline cost of debt (using Ofgem approach)	3.3%
NI-specific debt premium	1.0%
Cost of debt (pre-tax, real)	**4.3%**
Gearing	60.0%
WACC (vanilla, real)	**5.7%**

Source: Frontier calculations

Note: * Assumes asset beta of 0.42, debt beta of 0.1 and gearing of 60%.

1 Methodological approach and structure of this report

In 2011 Frontier Economics was commissioned by NIE to provide a report setting out its view on the appropriate weighted average cost of capital for NIE for the RP5 period. Our final report, dated May 2011, was submitted to the Utility Regulator by NIE.

The Utility Regulator has now published its Draft Determination for RP5. Given that approximately one year has passed since we submitted our last paper, NIE has asked us to provide an updated view on the appropriate cost of capital for NIE for RP5, taking account of recent developments and in particular the Utility Regulator's Draft Determination. This report provides an update to our May 2011 paper.

Below we describe the methodological approach that we adopted in our May 2011 paper. We still regard that approach as the right one and we further believe that we can address the majority of the Utility Regulator's proposals within that structure. Consequently we have largely retained the structure of the May 2011 report for this paper.

However, the Utility Regulator's proposals do give rise to issues that we did not consider in our work for May 2011, the most important of which is the proposed reduction in asset beta for Fund 3 investments. To ensure a comprehensive review, we have provided a specific assessment of any arguments brought forward by the Utility Regulator that had not previously been considered.

In this introductory section we first outline out methodological framework for determining the WACC, and then outline the structure of the rest of the report that follows this approach.

1.1 Methodological approach

NIE is one of 15 DNOs in the United Kingdom. Fourteen of these DNOs are regulated by Ofgem, the GB energy regulator. NIE is regulated by the Utility Regulator. This institutional arrangement enables the regulatory agenda to be sensitive to specific local circumstances such as DETI's Strategic Energy Framework for NI. At the same time, it enables the Utility Regulator to incorporate the generic aspects of regulation that also apply to the DNOs in the rest of the UK, an approach which should ensure the NI regulatory framework can be readily understood by investors who are familiar with that which applies to DNOs in the rest of the UK.

These principles are already well established in regulatory custom and practice over several price control reviews, and have been reflected in aspects of NIE's

licence itself. The cost performance of GB DNOs has been used as benchmarks for NIE's cost allowances in previous regulatory reviews, and this will continue at RP5. Furthermore, the current licence transposes the cost of capital set by Ofgem at DPCR5 into NIE's regulatory allowance for the remainder of RP4 (although this reflects the headline Ofgem WACC rather than the effective return that applied).

Given this background, we have developed an assessment of NIE's cost of capital that takes, as a firm basis, the settlement for the 14 other UK DNOs. However, our approach is flexible enough to reflect specific factors that apply to NIE and any significant changes to market conditions. Our assessment is comprised of three stages.

- **Stage 1** develops the foundation for any assessment of NIE's cost of capital for RP5 as Ofgem's determination for the 14 GB DNOs at DPCR5. The DPCR5 WACC decision cannot be interpreted in isolation of the rest of the settlement since it is intertwined within a wider regulatory framework developed by Ofgem for setting allowed returns. We argue that the starting point for RP5 needs to reflect not just the headline WACC allowed by Ofgem at DPCR5, but the actual baked-in returns that DNOs were allowed, which Ofgem's RORE analysis demonstrated are in excess of the baseline WACC. Failure to do so would result in unfair remuneration to NIE's investors for the risks and opportunity costs of investment that they bear when supplying capital to finance NIE's operations.

- **Stage 2** enables the adjustment of the WACC calculated at Stage 1 to take account of relevant NIE-specific factors.

- **Stage 3** in our original report evaluated whether financial market evidence on the WACC has changed significantly since DPCR5, to such an extent that merits a change to the parameters of Ofgem's decision. In this report we update that analysis to reflect the latest market evidence. We also evaluate the Utility Regulator's detailed WACC proposals and present an assessment of whether those arguments, or changing evidence, might lead us to change our view.

Note that our first paper for NIE included a fourth stage, in which we assessed the financeability of NIE's business at our proposed cost of capital. We have not considered financeability as part of this update, but we understand that NIE intends to undertake its own analysis in this respect.

1.2 Structure of the report

Given this approach, our report is structured in the following two sections:

Methodological approach and structure of this report

- Section 2 sets out our framework for determining NIE's allowed returns at RP5. Within this framework we develop the rationale for using Ofgem precedent from DPCR5 as the starting point for an assessment of NIE's allowed returns. We then identify the areas where that precedent should be adjusted in order to take account of NI-specific factors.

- Section 3 evaluates the Utility Regulator's draft proposals in the context of the changes in market conditions since DPCR5.

2 A framework for setting a fair WACC for NIE at RP5

In this section we develop a framework for setting a fair and reasonable WACC for NIE at RP5. Our framework takes into account the risks and opportunity costs of investment faced by NIE's investors, and is flexible enough to reflect market evidence as it emerges.

In our view, the starting point for any assessment of NIE's cost of capital should be the allowed returns determined by Ofgem at DPCR5. As we set out in our May 2011 report, as far as Ofgem precedent for the WACC at DPCR5 is concerned, it cannot be interpreted in isolation of the rest of the settlement since it is intertwined within Ofgem's wider regulatory framework for setting allowed returns. We presented:

- an analysis of the approach Ofgem took to calibrating the cost of capital at DPCR5, taking fully into account the fact that the headline settlement for the cost of capital was only one of the routes through which equity returns were allowed, as demonstrated by Ofgem's return on regulatory equity (RORE) analysis; and
- The risks posed by departing from the cost of capital implied by this holistic view of Ofgem's settlement, both in general, and in the light of NIE's efficiency performance.

In our view the appropriateness of applying Ofgem'sDPCR5 precedent to NIE at RP5 remains unchanged. In section 2.1 below, we explain our reasons for this view. In section 2.2 we review certain NI-specific factors and consider their potential impact on NIE's cost of capital, vis-à-vis the returns allowed to GB DNOs at DPCR5. Section 2.3 sets out our key conclusions on the framework that ought to be applied to determining NIE's allowed returns at RP5.

2.1 Application of DPCR5 precedent to RP5

2.1.1 Ofgem's RORE approach

Expected returns allowed to GB DNOs at DPCR5

As we described in our May 2011 paper, at DPCR5, Ofgem adopted a new approach to the cost of capital. According to this approach, the headline cost of equity (6.7%) was set artificially lower than the effective total return on regulated equity that an average performing DNO was going to get. The difference between the RORE and the baseline cost of equity were the additional returns "baked in" to the settlement if DNOs meet their efficiency targets.

The key conclusions of that May 2011 analysis remain:

- while the headline cost of equity for DPCR5 was 6.7%, in practice all DNOs were anticipated to earn returns in excess of this level if they were simply able to meet, not beat, Ofgem's target;
- the minimum "baked in" returns on equity for the DNOs Ofgem assessed as worst performing at the time of DPCR5 review was 7.1%, with the average at 7.7% and maximum at 9.6%; and
- most DNOs were anticipating that, in practice, they would earn returns beyond this level through beating Ofgem's targets.

In order to earn equity returns at the headline level, DNOs would need to systematically and materially underperform Ofgem's expectations.

Returns realised by GB DNOs since DPCR5

Since our May 2011 paper was prepared Ofgem has published a report that includes an assessment of the GB DNOs financial performance during 2010/11, the first year of DPCR5. This allows us to gain a first indication of whether our expectations of returns to equity for GB DNOs were reasonable.

The results of Ofgem's assessment of the first year of DPCR5 are reproduced in **Figure 1**.

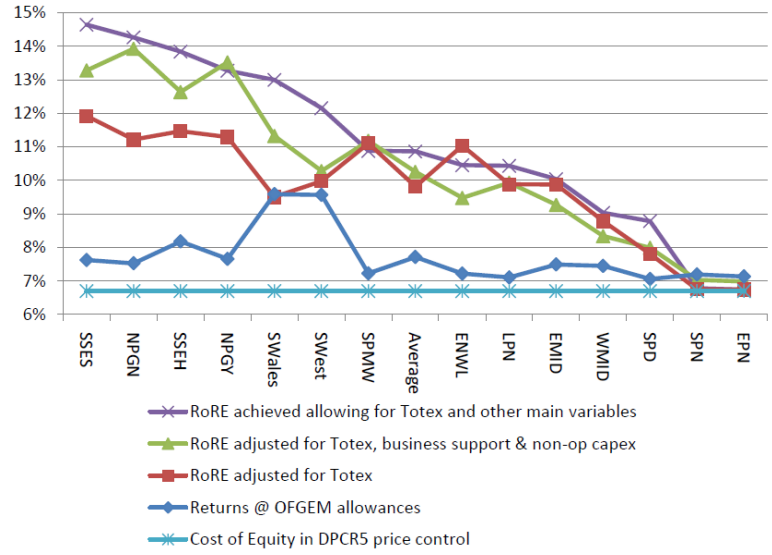
The light blue curve represents the baseline return on equity set by Ofgem at DPCR5 (i.e. 6.7%). The dark blue curve reflects Ofgem's expectation of returns for companies that meet their targets. The red, green and purple curves represent the GB DNOs' realised returns, calculated using outturn performance against different sets of incentives. For example, the red curve shows the companies' returns taking into account only over/under spend on totex. The green curve takes into over and under spend on business support and non-operational capex as well as totex. The purple curve takes account of over and under spend on all costs together with outturn performance against the main DPCR5 incentive mechanisms.

Ofgem has found that, in respect of totex improvements alone, all the DNOs except South East Power Networks and Eastern Power Networks have achieved returns in excess of the baseline cost of equity allowed at DPCR5. If efficiency improvements on business support and no-totex costs are taken into account, all 14 GB DNOs have achieved returns above their baseline cost of equity. Moreover, the purple curve shows that many DNOs have earned returns far in excess of the "baked in" level of returns with ten DNOs earning real returns on equity in excess of 10%.

This evidence does need to be interpreted carefully because at the time of the assessment only a year had elapsed since the price control had come into effect. Ofgem notes that these returns are indicative only as they may be influenced by

deferment of capital expenditure, which would reverse in later years. Therefore, an assessment conducted after a number of years into the price control would provide a more accurate picture of the actual returns to the GB DNOs. Nevertheless, on the evidence so far there is no reason to believe that a large number of the GB DNOs will not be able to comfortably achieve returns in excess of the DPCR5 baseline cost of equity.

Figure 1. Return on Regulated Equity (RoRE) achieved versus allowed cost of equity, ranked by RoRE in descending order



Source: Ofgem, *Electricity Distribution Annual Report for 2010-11*, 30 March 2012

Consequently, our conclusion from Stage 1 of the analysis remains that the return on equity allowed to NIE should reflect GB precedent. This requires a RORE uplift to be applied to NIE's estimated baseline cost of equity, provided that NIE is at least as efficient as the average GB DNO (see Section 2.1.2 below). In DPCR5 Ofgem allowed a baseline cost of equity of 6.7%, and a RORE for the average GB DNO of 7.7%. This reflects a RORE uplift of 1.0% to the baseline real cost of equity. In our view, the Utility Regulator should apply this 1.0% uplift to NIE's estimated baseline cost of equity.

2.1.2 The effect of not reflecting Ofgem precedent at RP5

In our May 2011 paper there were two parts to our conclusion in respect of GB precedent. The first related to the generic cost of capital that should apply to NIE as one of 15 UK DNOs, where that determination has already been made for 14 of those businesses. The second relates to the variable efficiency uplift that most DNOs earned, and which should also apply to NIE given that it was assessed to be a well-performing DNO.

The effect of not allowing NIE the generic expected return earned by all other UK DNOs

We described that NIE's closest competitors in the market for capital are the fourteen other DNOs in the UK, who operate under an almost identical regulatory framework to NIE. Ofgem expects these other UK operators to earn a vanilla WACC of 5.04% on average simply for meeting (not beating) their performance targets, and as we have shown above, early evidence on DPCR5 indicates that most companies are earning greater returns than this. If NIE faced a regime that was generically similar in all respects save for a lower cost of capital, then this would be perverse, and would be recognised as such by the financial markets. The methodology that we developed – as well as the WACC that results from its application – would provide clarity to investors that NIE will be able to earn equivalent returns to the DNOs in the rest of the UK, after taking account of objectively justifiable differences. Departure from this objective assessment at RP5 and in the future would make on-going equity investments in NIE relatively less attractive.

The effect of not allowing the uplift for NIE's efficiency that has been allowed for most of the other UK DNOS

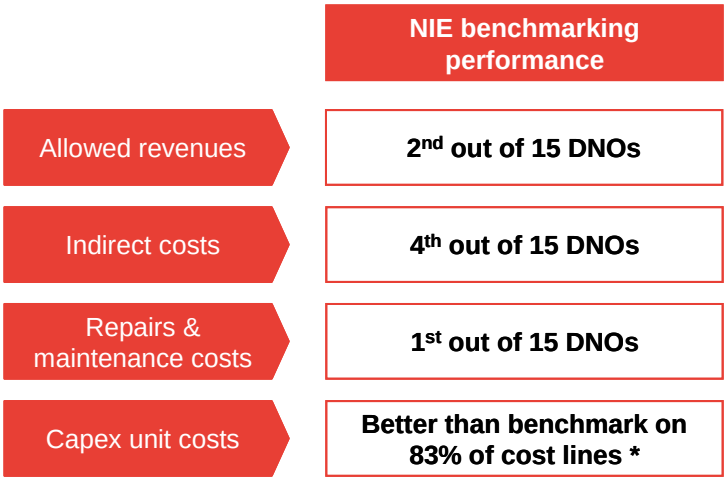
In our May 2011 paper we provided a discussion of the rationale for providing an uplift to NIE's returns on equity to reflect its above average level of efficiency relative to the GB peer group. Such an uplift would be consistent with the treatment NIE would receive if it were regulated by Ofgem. Provided that updated evidence on NIE's efficiency continues to demonstrate that NIE is a leading performer in the wider UK peer group, we remain of the view that such an uplift is justified, for the reasons we set out in our previous report.

We have reviewed the efficiency analysis presented by the Utility Regulator in its Draft Determination, which suggests that there are areas where NIE's performance might lag behind prevailing GB levels. We have provided NIE with an assessment of the Utility Regulator's analysis and have also updated the efficiency analysis we undertook in support of NIE's business plan submission. Based on this assessment, we remain of the view that NIE should be regarded as a leading DNO across both its opex and capex spend.

Figure 1 below summarises the results of benchmarking exercises on both NIE's opex relative to DNOs, and also its capex relative to both DNOs and other comparators. These results clearly indicate that NIE is a better than average performer in each element of the benchmarking and demonstrates NIE as a leading UK DNO.

A framework for setting a fair WACC for NIE at RP5

Figure 2. NIE's performance in benchmarking exercises



Source: Frontier Economics and PB Power benchmarking reports on NIE

* Note: this score is likely to underestimate NIE's capex unit cost efficiency, as the NIE costs used in the analysis include an allocation of some indirect costs.

Overall these benchmarking results indicate that a GB DNO operating at NIE's estimated level of performance would have earned an even greater return than the average allowed, so the use of a 7.7% return on equity as the Ofgem DPCR5 equivalent level for NIE represents a somewhat conservative application of the methodology we have developed in this report, particularly in the light of evidence from the first year of DPCR5.

2.2 Adjusting for NI-specific factors

In our May 2011 report we identified gearing as a specific difference between NIE and the GB DNOs that needs to be accounted for in any assessment of the cost of capital.

We have assessed the Utility Regulator's proposed level of gearing (i.e. 60%) and do not regard it as unreasonable, provided NIE is permitted to gear up to those levels. A fuller discussion of gearing is presented in Section 3.1.2 below.

However, since our May 2011 report was drafted, we have become aware of evidence of a systematic difference between the yields to maturity of NI based utility bonds (specifically NIE and PNG) versus GB utilities (in particular the DNOs). In Section 3.1.1 we review this evidence and provide a suggested treatment, which is to adjust Ofgem's treatment of debt to take account of this NI specific premium. Moreover, the same NI-specific risk factors that contribute to a higher cost of debt also affect the cost of equity for a NI utility company. In Section 3.2.5 we review why and how an NI-specific premium should be taken into account when determining the cost of equity.

2.3 Key conclusions on a reasonable framework for setting NIE's allowed returns at RP5

We remain of the view that the cost of capital Ofgem allowed at DPCR5 should be the basis of NIE's settlement at RP5. Particularly, the WACC should properly reflect not just the headline parameters, but the baked-in return as well.

We also take the view that the allowed cost of capital should take account of the evidence that it is more costly for NI-based utilities to raise debt than it is for GB based utilities. While the method adopted by Ofgem to estimate the cost of debt for the GB DNOs remains reasonable, it therefore follows that this level should be uplifted to account for this NI specific premium.

3 Evaluation of the Utility Regulator's draft proposals and latest market evidence

In this section we evaluate the Utility Regulator's draft proposals, considering the extent to which the financial market evidence has changed since our previous submission. We consider each of the key parameters individually, focusing on those parameters on which we disagree with the Utility Regulator.

3.1 Cost of debt and gearing

3.1.1 Cost of debt

NIE argued for a cost of debt of 3.6% (pre-tax real) in its response to the BPQ. This was in line with Ofgem's decision at DPCR5, which set the debt costs for the GB DNOs on using a 10-year trailing average of debt costs for a broad sample of companies. In contrast, in its Draft Determination, the Utility Regulator estimated NIE's cost of debt by taking an average of the interest rates on two tranches of NIE debt:

- a £175m bond which matures in 2018; and
- a £400m bond which matures in 2026.

These nominal rates were then deflated to obtain a real cost of debt. In order to do this First Economics advised that the Utility Regulator "uses the RPI forecasts that it is using across the RP5 review in this conversion". However, as these forecasts are yet to be finalised, in its Draft Determination, the Utility Regulator used OBR forecasts of inflation over the five-year control period to deflate the nominal yields.[1]

In our view, the Ofgem approach of using a trailing average of debt costs is preferable to the Utility Regulator's approach to estimating the cost of debt:

- It takes into account prevailing market conditions and provides for a smoother profile of financing cost allowances over time than if spot rates were employed. This is particularly important for companies such as NIE, who need to raise capital in order to make essential investments, even during periods of financial market turmoil.

[1] These forecast resulted in an average inflation rate of 3.35%. Current and historic levels of breakeven inflation derived from the UK gilts markets, which arguably over estimate inflation, show 10 year breakeven inflation currently as 2.51% and as a 10 year average 2.86%. Ofgem is currently using 10 year breakeven inflation as part of the RIIO model for price control determination.

- It puts NIE on an even footing with GB DNOs, who will be seeking debt finance over the coming years.

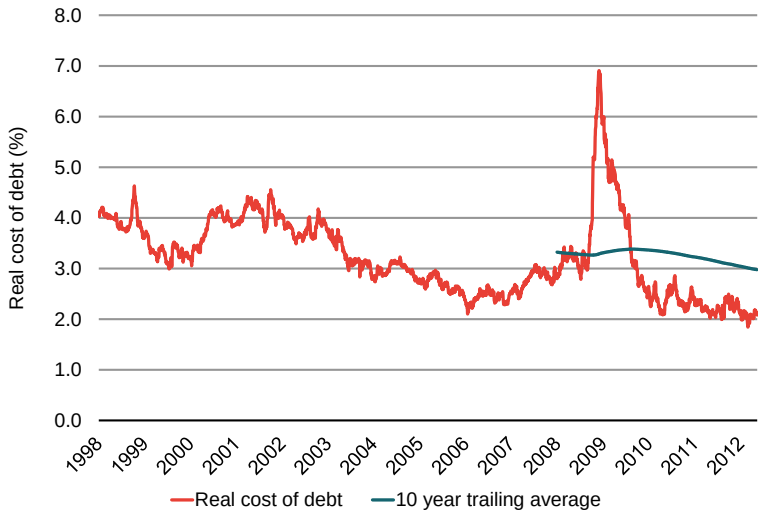
Application of GB precedent to the cost of debt

In DPCR5 Ofgem made it clear that focussing on short-term trends would be inappropriate, even during periods of extreme market turbulence. In order to avoid its determination of the cost of debt being driven off very short-run market movements, Ofgem applied a 10-year trailing average when determining the allowed debt costs of GB DNOs:[2]

> "**We continue to believe that long-term averages represent the most appropriate basis for setting the cost of debt.** We do not think that there is any compelling evidence that the recent turmoil in the financial markets has made this any less appropriate or that there has been a fundamental shift in the cost of debt following the financial crisis. We estimate that the ten year rolling average of the cost of debt for issuers of a similar credit rating to the DNOs is just under 3.3 per cent." (Emphasis added)

The real average yield implied by the bond index is plotted over time in **Figure 3** below.

Figure 3. iBoxx 10+ years A and BBB GBP non-financial bonds



Source: Markit data; Frontier calculations

As shown above, the current measure of the 10-year trailing average is approximately 3.0%.

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2 Ofgem, 2009, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenues and Financial Issues*, p.9.

However, it is important to note that Ofgem did not apply the 10-year trailing average mechanistically. It allowed a spread (approximately 30 bps) over the trailing average which we understand was added to compensate the DNOs for the uncertainty created by fixing this rate for the entire price control period..

> **"In light of all the evidence, we believe that a plausible range for the cost of debt is 3.3 to 3.7 per cent.** Our point estimate is in the upper half of this range and reflects the fact that a degree of macroeconomic uncertainty arguably remains. **In conclusion, we consider that a cost of debt of 3.6 per cent is appropriate for DPCR5."**(Emphasis added)

The Utility Regulator should maintain consistency with Ofgem's methodology and apply similar 30 bps headroom. Doing so would result in a cost of debt of 3.3%. In our view, this is the **minimum** cost of debt that could justifiably be allowed to NIE in RP5.

The Utility Regulator should account for the fact that NI debt has a higher yield to maturity than GB debt

There is also evidence that NIE's debt financing costs are higher than those of the GB DNOs, as the Utility Regulator's advisers, First Economics, acknowledge. We agree that the Utility Regulator should take account of this fact when determining an appropriate debt allowance.

First Economics stated in its report to the Utility Regulator that the difference between NIE's borrowing costs and those of the GB DNOs "could be explained by a range of other factors, such as it being NIE's first foray into the public bond markets, NI specific risk factors that might be of concern to lenders and NIE T&D's relatively smaller size".[3] We agree that these could be reasonable explanations for why NIE's borrowing costs exceed those of the GB DNOs.

First Economics quantifies the spread between NIE and GB DNO borrowing costs as 50-60 bps. However, we note that this estimate is based on an examining the relative difference between *coupon rates* of NIE and GB DNO debt. In our view, this is not a sound basis to assess relative borrowing costs.

Although the coupon reflects the stream of interest payments promised for that particular instrument it does not reflect the current cost of debt. Bonds trade based on their yield, which reflects the nominal level of return investors expect from the company. This is a closer reflection of the company's nominal cost of debt (before new issue costs/premiums) at the point in time they choose to raise new debt finance.

The correct basis on which to compare expected returns to bond investors is the yield to maturity (redemption yield). We note that the Ofgem methodology for

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3 First Economics, *An estimate of NIE T&D's costs of capital*, 11 December 2011, p.12.

setting debt cost allowances is based on yields to maturity (through the iBoxx index) rather than coupon rates.

In order to assess the size of the NI debt premium, vis-à-vis GB debt costs, we compared the yield to maturity on NIE's most recently issued publicly traded bond due to mature in 2026 against the yield on comparator GB DNO bonds.[4] To ensure comparability, we only considered GB DNO bonds with a credit rating similar to NIE's bond (i.e. close to BBB+ using S&P's rating system; Baa1 using Moody's system), and a similar time to remaining maturity (i.e. bonds due to mature between 2025 and 2027). We identified 6 such comparator bonds, which are reported in **Table 1** below.

Table 1. NIE and comparator GB DNO bonds

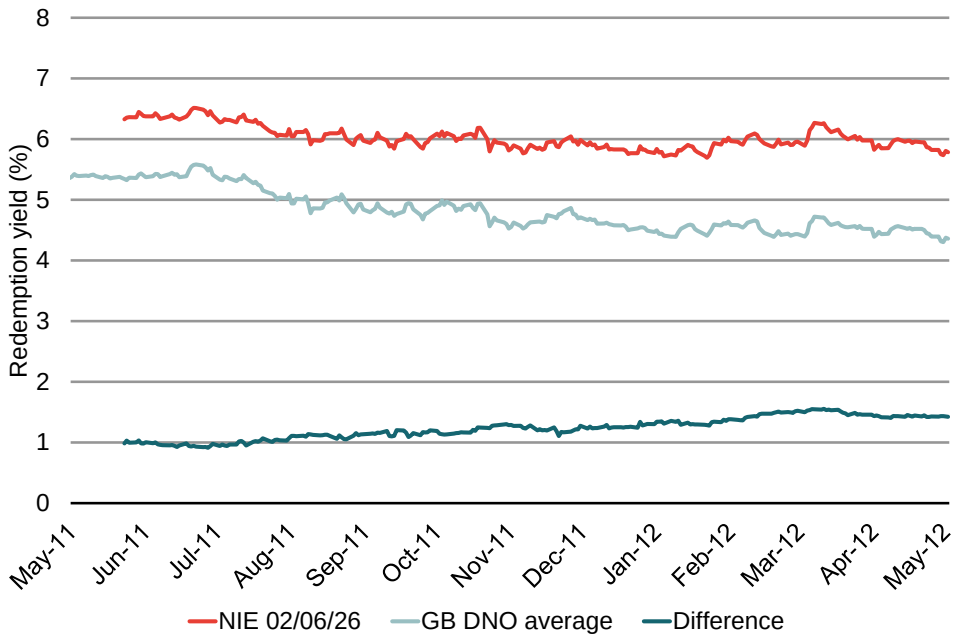
Issuer	Issuance year	Maturity date	Rating
NIE	*2011*	*02/06/2026*	*BBB+*
Eastern Power Networks	1995	31/03/2025	BBB+
Electricity North West	1995	25/03/2026	BBB+
London Power Networks	2002	07/06/2027	BBB+
South Eastern Power Networks	2003	05/06/2026	BBB+
Western Power Distribution: South West	2010	09/05/2025	BBB
Western Power Distribution: South West	2003	25/03/2027	BBB

Source: Thomson Datastream

We then calculated the mean yield on the 6 GB DNO bonds over time and compared this series to the yield on NIE's bond since its issuance in 2011. The results are plotted in **Figure 4** below.

4 The outstanding NIE bond which matures in 2018 is traded very thinly, and we only found two appropriate GB comparators.

Figure 4. Difference between NIE and average GB DNO redemption yields



Source: Thomson Datastream; Frontier analysis

Since its issuance in 2011, the redemption yield on NIE's bond has on average been approximately 123 bps greater than the average redemption yield on comparable bonds issued by GB DNOs.[5]

In order to check whether this phenomenon is specific to NIE, we repeated this analysis with Phoenix Gas's publicly traded bond, which is due to mature in 2017. Apart from the aforementioned NIE bonds, Phoenix's 2017 bond is currently the only listed debt issued by a NI utility.

As with the NIE bond, we were careful to only select comparator bonds with a similar credit rating to Phoenix's bond (i.e. close to Baa2 using Moody's rating system; BBB using S&P's system), and similar time remaining to maturity (i.e. bonds due to mature between 2016 and 2018). With these criteria, we were able to identify two bonds issued by GB gas network companies. Next, we widened the search to also permit GB gas network bonds that mature in the period of 2015-19 and comparable bonds issued by other GB utility networks (i.e. electricity and water). Doing so allowed us identify three more comparator

5 The NIE 2018 bond has a similarly high premium over its two GB comparators, Western Power 2020 and Yorkshire Electricity 2020. However, due to its thin trading and lack of comparators, we focus on the NIE 2026 bond for the purpose of this comparative analysis.

bonds, one from the gas sector and two from the water industry. The five comparator bonds are as reported in **Table 2**.[6]

Table 2. Phoenix Gas and comparator GB utility bonds

Issuer	Issuance year	Maturity date	Rating
Phoenix Gas	*2009*	*10/07/2017*	*Baa2*[7]
Wales and Western Utilities (gas)	2009	02/12/2016	Baa1
Southern Gas Networks (gas)	2009	02/11/2018	BBB
Northern Gas Networks (gas)	2009	08/07/2019	BBB+
Northumbrian Water (water)	2001	11/10/2017	BBB+
United Utilities Water (water)	2003	14/05/2018	BBB+

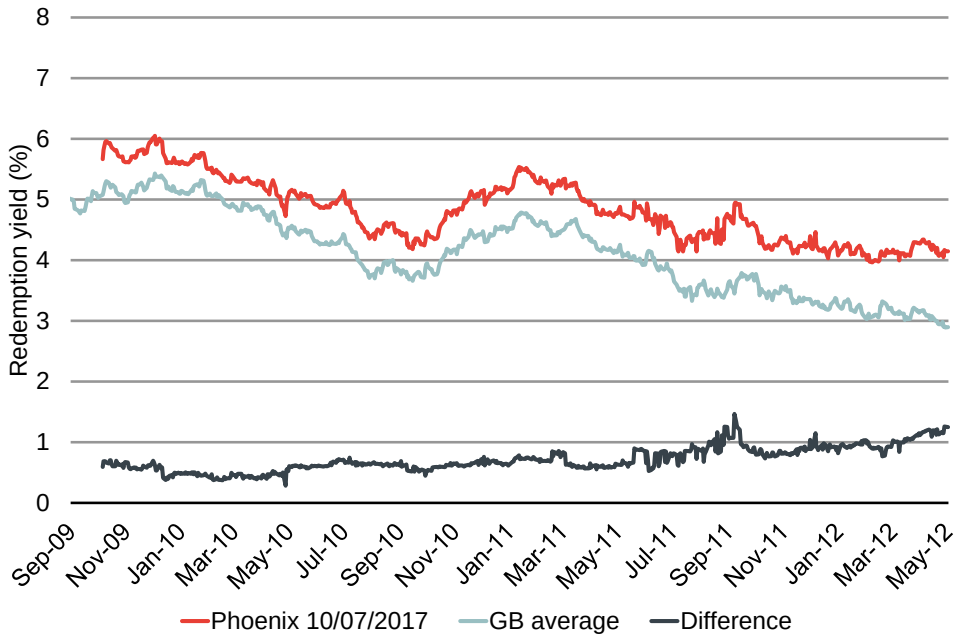
Source: Thomson Datastream

Figure 5 plots the yield on Phoenix Gas's 2017 bond against the mean yield within our GB comparator set. As with NIE, above, there is a significant difference between the debt financing costs of Phoenix Gas and GB comparators (74 bps on average).

6 Although this is a relatively modest sample of comparators, we note that First Economics used even fewer comparator firms (two) in its analysis to articulate the spread in borrowing costs between NIE and GB peers. See First Economics, *An estimate of NIE T&D's costs of capital*, 11 December 2011, p.12.

7 Phoenix bond has a Moody's rating of Baa2, which is equivalent to BBB from S&P rating.

Figure 5. Difference between Phoenix Gas and average GB comparator redemption yields



Source: Thomson Datastream; Frontier analysis

This evidence suggests that the premium observed between NIE's yields and GB comparators is not unique to NIE, but indicative of generally higher borrowing costs for NI utilities.

While this evidence does suggest that the premium appears to be greater for NIE than for Phoenix Gas in our view, this supports an NI-specific adjustment of at least 100 bps (potentially as high as 123 bps) over the 3.3% cost of debt implied by Ofgem's methodology.

Having observed that there is a premium over broadly similar GB debt associated with bonds issued by NI utilities, this gives rise to the question of whether a similar premium will also be required by equity investors in NI. We address this question in the following section, where we assess the evidence on the returns expected by equity investors.

3.1.2 Gearing

In our May 2011 paper we argued that the level of gearing assumed for the purposes of calculating NIE's cost of capital should be adjusted from the DPCR5 precedent (65%) to 57.5% in the light of NIE's greater level of operational risk, compared to the GB DNOs. In its Draft Determination, the Utility Regulator has proposed a gearing level of 60% but stated:

> "In line with the arrangement [sic] under RP4, we expect NIE to remain below a 60% gearing level."

We consider that the Utility Regulator's proposed gearing assumption is broadly consistent with our submission last year, and therefore not unreasonable. However we note the following points:

- When proposing its gearing assumption, the Utility Regulator did not say that NIE's gearing "should not exceed 60%", so the 60% assumed by the Utility Regulator is not an upper bound. The Utility Regulator's chosen form of words plainly means that NIE should maintain a level of gearing that is **strictly below** 60%. It is unreasonable for the Utility Regulator to allow a rate of return by assuming a gearing level that it describes within the same decision as impermissible. If the Utility Regulator intends to maintain its gearing assumption of 60%, NIE should be permitted to leverage up to that level.

- The Utility Regulator's adviser, First Economics, set out to estimate an "optimal" level of gearing, and the Utility Regulator has agreed with First Economics' analysis. A level of gearing cannot be "optimal" if there is no prospect of the firm achieving it (in this case because the Utility Regulator has instructed that NIE should remain below the "optimal" level).

We also note that there is a conceptual mismatch in the way the Utility Regulator has treated debt and gearing. The Utility Regulator has chosen to apply a *notional* gearing assumption of 60%, which is well above NIE's actual gearing level of 46%.[8] Yet, the Utility Regulator has proposed a cost of debt allowance on the basis of NIE's actual borrowing costs, which will reflect its *actual* (not notional) level of gearing. If the Utility Regulator wishes to apply a gearing assumption of 60%, it needs to be internally-consistent and allow a cost of debt that is commensurate with the risks of moving to that capital structure. This would call for a cost of debt allowance in excess of the 3.2% proposed in the Utility Regulator's Draft Determination.

3.2 Cost of equity

In its response to the BPQ, NIE argued for a cost of equity of 7.7% (post tax real). In its Draft Determination, the Utility Regulator proposed a post-tax real cost of equity of 6.32%.

We note that under the DPCR5 settlement Ofgem determined a baseline real post-tax cost of equity of 6.7%. However, under DPCR5 the lowest allowed

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8 the Utility Regulator, *Northern Ireland Electricity Transmission and Distribution Price Controls 2012-2017, Draft Determination*, 19 April 2012, para. 18.20.

expected return on equity for any DNO was 7.1%, taking into account 'baked in' returns for meeting not beating Ofgem's allowances.

We continue to believe that the cost of equity of 7.7% argued for by NIE in its BPQ is reasonable, if not conservative. In the remainder of this section we set out the reasons why, and address a number of points that the Utility Regulator has raised in relation to specific components of the cost of equity in its Draft Determination.

3.2.1 Real risk-free rate

In our May 2011 paper we argued for a real risk-free rate of 2.0% on the basis of consistency with Ofgem's DPCR5 determination, and on the basis that good regulatory practice involves taking a long-term view of market parameters during periods of anomalous economic activity.

In its Draft Determination, the Utility Regulator proposed a real risk-free rate of 2.0%. Our position since our May 2011 remains unchanged. Therefore, we agree with the Utility Regulator's proposal on the risk-free rate.

3.2.2 Equity risk premium (ERP)

In our May 2011 paper we presented various sources of evidence on the ERP and argued that Ofgem's estimate of 5.25% at DPCR5 remains within the range implied by market data.

We note that in March 2011 Ofgem published an estimated range for the ERP of 4.75% to 5.5% and indicated its preference to use the top half of this range.[9] Ofgem's DPCR5 estimate of 5.25% is comfortably within the top half of this range. Furthermore, Ofgem's recent RIIO T1 decisions on SHETL and SPTL, published in late April 2012, used a cost of equity that is underpinned by the ERP range it estimated in March 2011.[10] This reaffirms that the most recent GB precedent is closely aligned with the DPCR5 determination on the ERP.

In its Draft Determination, the Utility Regulator proposed an estimated range for the ERP of 4.5% to 5.0%, and settled on a point estimate of 4.8%. The Utility Regulator obtained its ERP range by estimating a range for the market return on equities of 6.5% to 7.0% and adjusting these values using its risk-free rate estimate of 2.0%.

The Utility Regulator's range for the market return on equities was derived solely by examining past UK regulatory decisions (eight decisions between 2006 and

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9 Ofgem, *Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues*, *Supplementary Annex (RIIO-T1 and GD1 Overview papers)*,31 March 2011, p.33.

10 Ofgem, *RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd, Final decision – Overview document*, 23 April 2012, p. 18 and p.23.

2010; one decision in 2011). Several of these decisions are now a number of years old. The Utility Regulator has chosen to rely on these data even though it says in its Draft Determination that it "considers that the most up-to-date information should be used in WACC assessments" (p.167).

By basing its estimates exclusively on past regulatory decisions, the Utility Regulator has ignored important, current market evidence. This evidence includes:

- Dimson-Marsh-Staunton (DMS) estimates of average historic market returns for UK equity investor;
- forward-looking estimates of equity returns derived from dividend growth model analysis conducted by the Bank of England; and
- estimates based on surveys of UK academics, analysts and company executives.

We discuss each of these pieces of market evidence in turn:

Long-term historic evidence support an ERP of 5.0%

A common approach to estimating ERP is to look at long-term historic evidence. One of the most comprehensive analyses of historic ERP data is a dataset presented by Dimson, Marsh and Staunton (DMS, 2012).[11] The authors estimate the average ERP and equity returns for 19 countries, including the UK, using historical returns data from 1900 to 2010, as well as an ERP for a 'world' index and a European index.

The DMS analysis suggests that most recent historic (arithmetic) average measure of the ERP for the UK is 5.0%, and that the (arithmetic) average, real historic equity return for the UK is 7.1%. Applying the Utility Regulator's estimate for the risk-free rate, 2.0%, to the latter figure would imply an ERP of 5.0%.[12]

Forward-looking estimates suggests an ERP in excess of 7.0%

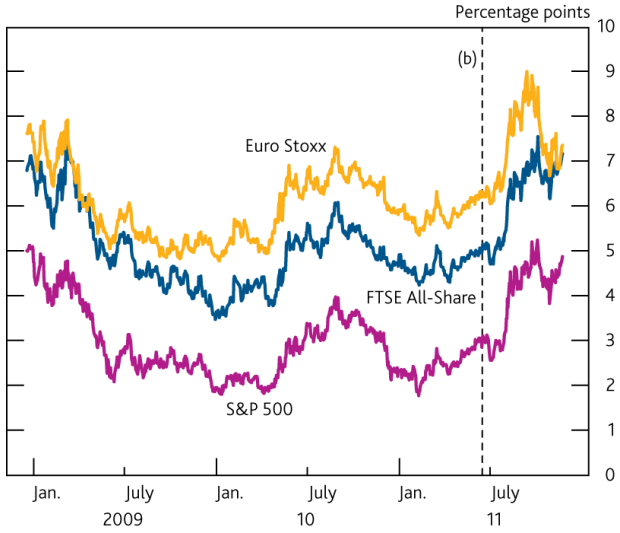
The Bank of England infers the ERP by applying a multi-stage dividend growth model (DGM) to a broad UK stock index to estimate the required return on that index. It then calculates the excess return on equities by subtracting the risk-free rate. **Figure 6** presents the Bank of England's estimates over the past three years. The middle line marked "FTSE All-Share" is the relevant one for the UK. Examination of the peaks and troughs over this period suggests an ERP range of 3.4% to 7.6%. The Bank of England's most recently published estimate is close

11 Dimson, E., Marsh, P., Staunton, M. (2012), *Credit Suisse Global Investment Returns Sourcebook 2012*.

12 DMS calculate excess market returns as: $\frac{1+\text{Market return on equity}}{1+\text{Risk-free rate}} - 1$.

to 7.2%.[13]Applying the Utility Regulator's estimate of 2.0% to this figure would result in a forward-looking market equity return of approximately 9.2%.

Figure 6. Equity Risk Premium, Bank of England[(a)]



Source: Bank of England (2011), *Financial Stability Report*, December

(a) As implied by a multi-stage dividend discount model.

(b) June 2011 Report.

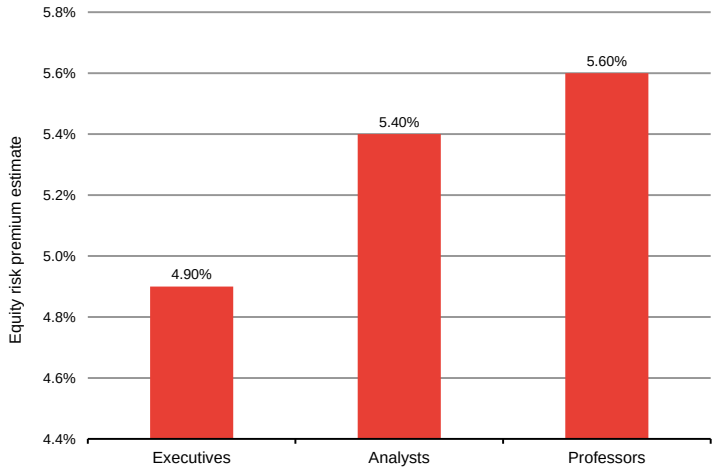
Survey evidence suggests an ERP range of 4.9% – 5.6%

Finally, Fernandez et al (2011) surveyed over 6,000 academics, analysts and company executives on the ERP they actually use.[14] Of the respondents, 112 related to the UK. The results are summarised in **Figure 7** below. The results of the survey suggest a range for the ERP between 4.9% and 5.6%. Applying the Utility Regulator's risk-free rate estimate of 2.0% to this range results in a market equity range of 6.9% to 7.6%.

13 Bank of England Financial Stability Report, December 2011, issue no. 30.

14 Aguirreamalloa, J., Corres, L. (2011), 'Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers', *IESE Business School working paper*

Figure 7. Recent survey evidence on the ERP for the UK



Source: Aguirreamalloa, J., Corres, L. (2011), 'Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers', *IESE Business School working paper*

Summary of evidence

Table 3 summarises this evidence.

Table 3. Market evidence on UK equity market returns and ERP

Source	Estimate of market equity returns	Estimate of ERP
Dimson, Marsh and Staunton historic returns, 2012, arithmetic average of UK returns measured between 1900 and 2011	7.1%	**5.0%**
Bank of England, DGM estimate, December 2011 most recent estimates, and range defined by high and low measured over past four years	9.2%*	Latest estimate: 7.2% Over past four years: 3.4% (min) to 7.6% (max) **Average: 5.5%**
Fernández, Aguirreamalloa and Corres survey, May 2011, using responses of UK financial academics, analysts and company executives	6.9% to 7.6%**	4.9% to 5.6% **Average: 5.3%**

Sources: Dimson, E., Marsh, P., Staunton, M. (2012), *Credit Suisse Global Investment Returns Sourcebook 2012*; Fernandez, P., Aguirreamalloa, J., Corres, L. (2011), 'Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers', *IESE Business School working paper*; Bank of England (2011), *Financial Stability Report*, December

Notes: * Calculated by applying the Utility Regulator's risk-free rate of 2.0% to the Bank of England's most recent DGM estimate of the ERP; ** calculated by applying the Utility Regulator's risk-free rate of 2.0% to the UK ERP estimate found in the Fernández et al survey

Taking into account the combined recent survey evidence, forward looking estimates and long-run historical averages, we would consider a range of 5.0% to 5.5% to be reasonable. We note that Ofgem's DPCR5 determination of 5.25% is within this range. This suggests that it is not unreasonable to retain Ofgem's DPCR5 ERP estimate for the purposes of RP5.

3.2.3 Asset beta

Transmission and distribution assets

In our May 2011 paper we argued that the Utility Regulator should take a long-term view of the asset beta, consistent with the approach taken by Ofgem in past price controls. The Utility Regulator proposed in its Draft Determination an asset beta of 0.42 for transmission and distribution assets. In our view, this is a reasonable estimate and consistent with the principle of adopting a long-term view, particularly during periods of extreme market turbulence.

Renewables-driven investments

The Utility Regulator has argued that the bespoke regulatory rules governing Fund 3 projects reduce NIE's exposure to systematic risk significantly in relation to renewables-driven investment. The Utility Regulator points specifically to new

rules that mean that it will be setting "renewables-related capex allowances throughout RP5 once the full scope and timing of the work is known". On this, First Economics, who derived an estimate of WACC for Fund 3 projects on behalf of the Utility Regulator states that:

> "If the Utility Regulator is proposing to move away from a five-year, fixed price deal for renewables-driven investment and towards project-by-project approval, it is as good as eliminating NIE T&D's exposure to this kind of economic risk."

The Utility Regulator has quantified the WACC for Fund 3 projects by simply reducing its proposed asset beta for NIE transmission and distribution activities by a margin of 0.1. This approach is flawed as there is no reason to believe that renewables-driven investments are intrinsically less risky than NIE's transmission and distribution assets. Indeed, having discussed the nature of these investments with NIE they have provided several reasons to believe that such investments may be more risky than non-renewables-driven investments:

- Fund 3 projects are more likely to require significant elements of entirely new construction activity on new 'greenfield' sites and/or on new land routes for infrastructure circuits (in contrast with the majority of 'business as usual' projects, which are be focused on the reinforcement, replacement or extension of existing assets). Where new overhead line routes are required this introduces significant uncertainty/risk in regard to the achievement of land-owner consents (both for the permanent works and also for matters such as land access for construction purposes). Public opposition to overhead lines, and the associated difficulties with land-owner consenting, is far more significant where new and significant lengths of overhead line are proposed.

- It might be presumed that the incremental greenfield risk noted above is largely removed by means of the pre-construction development. This is because once the project has been cleared for construction then: all of the development would have been completed; sites, routes and ground conditions would have been surveyed thoroughly; all necessary consents would be in place; and all tendered prices for delivery would be known. However, this presumption is fundamentally dependent on the scope and outputs actually achieved within the pre-construction stage. Since allowances for pre-construction will be subject to agreement with the Utility Regulator on a project-by-project basis, this introduces an element of circularity into any view on construction risk at a general level. The residual construction risks remaining for each project entering that final stage are dependent entirely upon what has been locked down with the Utility Regulator at the pre-construction phase.

- Whilst it may in principle be true that the achievement of land-owner consents removes a layer of construction risk, this is not necessarily the case where those consents have been imposed compulsorily on the land-owners (e.g. through court decisions). Compulsory wayleaves are a more likely outcome for significant new overhead line projects that are most likely to occupy Fund 3 than they will be for the business as usual investments. We understand from NIE that a number of T&D companies have experienced serious issues with civil disobedience/physical obstruction aimed at preventing construction activity, even where legally binding consents have been acquired.

- A project-by-project approach to capex approval arguably increases the risks faced by NIE by preventing the risk of cost overruns being diversified across multiple projects. Ordinarily, the provision of a regulatory allowance covers a portfolio of investments, which enables costs to be managed within that portfolio of projects

The only reason the Utility Regulator gives for applying a lower beta to Fund 3 investments, relative to NIE's existing transmission and distribution assets, is the introduction of new arrangements for approving capex related to such investments. The Utility Regulator does not make a case that Fund 3 investments are *intrinsically* less risky than NIE's existing transmission and distribution assets. The implication is that absent its new arrangements (i.e. if capex for these investments were approved through the normal price control process), Fund 3 investments should be considered to have the same exposure to systematic risk NIE's existing transmission and distribution assets.

GB regulatory precedent is clear that renewables-driven investments should be allowed the same returns as existing assets. In January 2010 Ofgem published its Final Proposals on the Transmission Access Review (TAR), which set out its approach to facilitating additional renewables-driven investments within the price control period under the Transmission Investment Incentives (TII) scheme. In those proposals, Ofgem stated that:[15]

> "3.19. In our Initial Proposals we proposed that these additional investments should be remunerated on the basis of the rate of return adopted under TPCR4 up to the end of 2011/12. The TPCR4 weighted average cost of capital (WACC) was 6.25% real pre-tax, 5.05% real vanilla and 4.38% real post-tax, all of which were based on an assumed gearing ratio of 60%.
>
> 3.20. **We consider that the projects for which we have made funding proposals do not differ materially in their risk profiles from the other**

15 Ofgem, *Transmission access review– Enhanced transmission investment incentives: Final proposals*, January 2010, p.30.

> **projects remunerated by the current TPCR4 cost of capital**, especially given the time horizon for our proposals is limited at this stage to the end of March 2012. Furthermore, we see the benefit of keeping the TPCR4 settlement whole and not causing an inconsistency in the way we treat transmission companies' RAV. **Taking these factors together, our final proposals on the cost of capital is to retain the existing provisions in TPCR4.**" (Emphasis added.)

We note that Ofgem's process for approving funding under TII mirrors the Utility Regulator's in the sense that funding for renewables-driven investment:

- may be granted during an existing price control period; and
- is only finalised once planning permissions for those investments have been received.

This is borne out in Ofgem's recent consultations on the TII funding for the Western HVDC link:[16]

> "1.7. The total cost[10] of the Western HVDC link (including substation works) is currently estimated to be in the order of £1 billion, although **there will remain uncertainty around both the level and profile of costs for the HVDC component pending completion of the TOs' ongoing tender evaluation process. Therefore [it] is not possible at this stage to specify the precise level of funding that may be required under TII in respect to costs incurred in 2011/12 and 2012/13 on the HVDC component, however this will be reviewed in more detail before we reach a final decision on the request**." (Emphasis added.)
>
> …
>
> "We also note that the ability of the TOs to proceed to construction works is **subject to their obtaining the necessary planning permission and construction consents from all of the relevant authorities with jurisdiction** on the proposed route of the Link, and where applicable addressing any licensing issues with the authorities of Northern Ireland and the Isle of Man."

Given that the Utility Regulator's proposals for approving renewables-driven investments is consistent with Ofgem's, it should follow GB precedent and allow the same rate of return on renewables-driven investments assets and NIE's transmission and distribution assets.

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16 Ofgem, *Transmission Investment Incentives: consultation on minded-to position for Western HVDC Link ("Western Bootstrap")*, 1 August 2011.

3.2.4 RORE uplift

As set out in section 2, we believe it is important that the Utility Regulator maintain consistency with GB precedent and allow a RORE uplift over and above NIE's baseline cost of equity. The RORE uplift applied in DPCR5 to the average GB DNO was 100 bps. We therefore believe this uplift should be applied to NIE's baseline cost of equity.

3.2.5 Adjusting for NI specific factors

The evidence so far has focused on the appropriate level of cost of equity for a company operating within GB. However, there is evidence suggesting that a higher level cost of equity for utility companies operating in NI may be more appropriate.

As section 3.1.1 on NIE's cost of debt demonstrates there is evidence to suggest that utility companies in NI face a debt premium over comparative GB utility companies – some 123 bps in the case of NIE 2026 bond. The NIE 2018 bond exhibits a similarly high premium, although it has few GB comparators and is very thinly traded making estimation of that premium challenging. We also note that the only publicly traded NI utility bond, Phoenix 2017 has a debt premium of 74 bps over its GB comparators.

The issue we need to address here is whether this observed premium on debt should also be reflected in an uplift to equity returns.

There is a large line of academic literature that studies the interconnection between debt premium and equity premium. These studies have found considerable evidence that suggests that common factors affect both the equity premium and debt premium on corporate bonds.[17] More specifically, cost of equity tends to be higher for those companies that have higher cost of debt.

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[17] Some example papers are:

- Keim, D. and R. Stambaugh (1986) Predicting Returns in the Stock and Bond Markets, Journal of Financial Economics 17, 357–90.
- Fama, E. and K. French (1989) Business Conditions and Expected Returns on Stocks and Bonds, Journal of Financial Economics 25, 23–49.
- Fama, E. and K. French (1993) Common Risk Factors in the Returns on Stock and Bonds, Journal of Financial Economics 33, 3–56.
- Campbell, J. and J. Ammer (1993) What Moves the Stock and Bond Markets? A Variance Decomposition for Long-Term Asset Returns, Journal of Finance 48, 3–37.
- Ferson, W. and C. Harvey (1999) Conditioning Variables and the Cross Section of Stock Returns, Journal of Finance 54, 1325–60.
- Cremers, K. (2002) Stock Return Predictability: A Bayesian Model Selection Perspective, Review of Financial Studies 15, 1223–49.

Some of the studies suggest that the increase in equity premium is proportional to the increase in debt premium. This would imply that a company with a debt premium of, say, 100 bps should command a similar equity premium, net of any liquidity premium in the bond market. In our view it is therefore reasonable to presume an uplift to required equity returns in line with the premium observed on debt, excluding any part of this debt premium that arises from low liquidity.

We have analysed what part of the debt premium described in Section 3.1.1 might arise from low liquidity by studying bid-ask spreads on the prices of the NIE and Phoenix Gas bonds relative to the set of comparator GB bonds.[18] For example, we find that the Phoenix bond has an average bid-ask spread of 1.5 compared to 0.88 for the GB comparators, implying that it is more expensive for investors to trade the Phoenix bond than a GB comparator's bond in the market.[19] The holder of the Phoenix bond would need to be compensated for an additional 0.62 over the period during which the bond was held. Where this has been considered previously by the Competition Commission, the presumed holding period was five years, which would imply that approximately 12 of the 74 bps (0.62/5) debt premium observed on Phoenix debt arises as a consequence of low liquidity. Similarly, the NIE 2026 bond has an average bid-ask spread of 2.18 compared with 1.49 for its GB comparators. This suggests that approximately 14 of the 123 bps premium over GB equivalent debt on the NIE 2026 bond might be associated with illiquidity, assuming again a holding period of five years. As noted above, we have not considered the premium associated with NIE's 2018 bond as this is very thinly traded making robust estimation difficult.

As the analysis presented above suggests that there may be a spread of at least 109 bps arising from factors not associated with low liquidity between NIE's bond yields and those of GB comparators, it may be argued that, if adjusting for NI-specific factors, the cost of equity for an NI utility should be about 109 bps higher than that of the GB comparators. In contrast, the evidence provided by the Phoenix 2017 bond, which has a smaller debt premium of 74 bps, would support a more conservative cost of equity uplift of at least 62 bps in the cost of equity for NIE. Our view is that an NI specific uplift to the cost of equity in the range 62 to 109 bps is therefore reasonable.

3.2.6 Summary of cost of equity

In its Draft Determination, the Utility Regulator suggests a post-tax real cost of equity of 6.32%. In this section we maintain that this does not take account of the RORE uplift of 100 bps that an average GB DNO is entitled to. Nor does it take account of the NI specific factors that suggest a further premium to the cost

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18 Bond prices here are nominalised to the par of 100.

19 For example, one might be able to buy the Phoenix bond for 101.5 and it could be sold for 100, while the average GB bond could be purchased for 100.88 and sold for 100.

of equity of at least 62 bps for NI utility companies. In our view these adjustments to expected equity returns are additive, implying an uplift of the equivalent GB estimate in the range 162 to 209 could be justified. This would imply that expected post-tax equity returns for an investor in Northern Ireland utilities could be as high as 8.8%. We therefore conclude that there is ample evidence that a post-tax real cost of equity of 7.7% as proposed by NIE is more than justified and might even be regarded as conservative.

3.3 Conclusions

Table 4 below summarises our estimates for each of the individual parameters, and presents our overall estimate for the WACC (vanilla, real).

Table 4. Summary of individual parameters and overall WACC estimate

Parameter	Frontier estimate
Risk-free rate	2.0%
ERP	5.25%
Equity beta* (transmission and distribution assets; renewables-driven investments)	0.90
Baseline cost of equity (real)	6.7%
RORE uplift applied to average GB DNO at DPCR5	1.0%
Expected return on equity (post-tax, real)	**7.7%**
Baseline cost of debt (using Ofgem approach)	3.3%
NI-specific debt premium	1.0%
Cost of debt (pre-tax, real)	**4.3%**
Gearing	60.0%
WACC (vanilla, real)	**5.7%**

Source: Frontier calculations

Note: * Assumes asset beta of 0.42, debt beta of 0.1 and gearing of 60%.

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APPENDIX 16A1

FINANCEABILITY IMPLICATIONS FOR NIE

Memorandum

From Rothschild
Date 10 July 2012

To Northern Ireland Electricity
Subject **NIE – Response to Draft Determination from the Utility Regulator**
Financeability implications for NIE

This paper addresses the financeability and credit rating implications for NIE associated with the Draft Determination received from the Utility Regulator.

Introduction

The Utility Regulator sets out allowed returns in the RP5 draft determination that are intended to enable NIE to finance itself efficiently through the bank or capital markets. The Utility Regulator acknowledges in the RP5 draft determination that it has a statutory duty to have regard to the need to ensure that NIE is able to finance its activities and states that:

> *"The longer term interests of consumers depend on maintaining the confidence of investors as value for money is maximised when a company can finance its activities efficiently.*"

This paper sets out our views on whether NIE can finance its regulated activities efficiently based on:

1. The context of the debt markets and NIE's access to the market to finance its activities;
2. The potential credit rating impact of the Draft Determination; and
3. The impact of the likely ratings outcome on NIE's ability to access debt markets and the cost of doing so.

Financing requirement and market access during a debt crisis

The debt markets are in crisis and debt capital is being rationed to companies with the strongest reputations and credit ratings within their peer group. Further, regulatory change is driving up the cost of capital for banks and bond investors affecting their appetite to lend. NIE will have a significant funding requirement over the course of RP5 and in common with other utilities this financing will come predominantly from listed sterling bond market or sterling bank markets.

UK sterling bond markets

NIE has £575m of sterling bonds outstanding. The sterling bond market is a highly ratings and reputation driven market and investors have a number of opportunities for investing in strong investment grade bonds (BBB+ and above) issued by regulated infrastructure companies across water, gas, electricity and transportation sectors in the UK. Further, the introduction of a set of new regulations (known as Solvency 2) for insurance companies will make it more capital intensive for insurers to invest in long dated bonds below a BBB+ rating.

UK bank markets

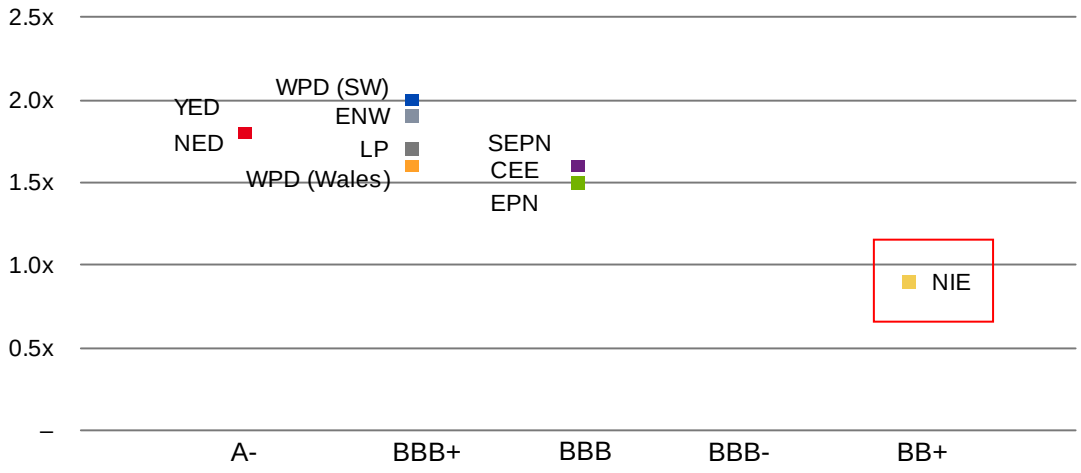
NIE does not currently have any term bank facilities and will have to build new banking relationships during RP5. The bank market in the UK is experiencing significant stress for a number of reasons which include (i) withdrawal of a large number of international banks from UK corporate lending due to their higher funding cost in sterling and (ii) Basel 3 regulations that require banks to allocate greater capital to loans is resulting in many banks shrinking their loan books and reducing the tenor of their loans (typically no more than 5 years). Against this volatile background in the bank markets, banks are focusing on lending opportunities where there is a prospect in the near future of a refinancing of any bank loans by issuance in the bonds markets. Accordingly, NIE's access to any bank funding is also heavily reliant upon maintaining a strong reputation in the capital markets.

In our view, NIE's ability to access the capital markets most efficiently is dependent upon stable financial performance, a predictable and stable regulatory environment and maintaining a strong and stable investment grade rating of at least BBB+.

Peer analysis – rating and financial metrics

NIE's main peers are the UK DNOs. In the chart below, we have mapped the rating of selected UK DNOs against the key credit metric used by Fitch, namely the minimum PMICR threshold for rating levels over the medium term. The Utility Regulator in its Draft Determination also identified PMICR as one of the key credit metrics and indicated that a PMICR of 1.5x is desirable.

Chart 1. PMICR ratio and rating for selected rated peers[1]



Source Fitch, Utility Regulators Draft Determination and NIE

[1]We have shown the ratings for 8 of the 14 UK DNOs and their holding companies. These DNOs are rated by Fitch and financed on a standalone basis so deemed to be most comparable to NIE. Of the other DNOs, North Scotland and Southern England and owned by SSE and are financed centrally by SSE. Scottish Power, which owns South Scotland and North Wales, Merseyside and Cheshire is owned by Iberdrola and although Scottish Power is rated by Fitch the rating is linked to the parent and the individual DNOs are not rated. WPD East Midlands and West Midlands are not rated by Fitch.

From this analysis of the comparables we can conclude the following:

1. The vast majority of peers funded on a standalone basis have a rating of BBB+ or higher

2. Under NIE's modelling of the draft determination case NIE falls well below the benchmark PMICR required for a BBB+ rating

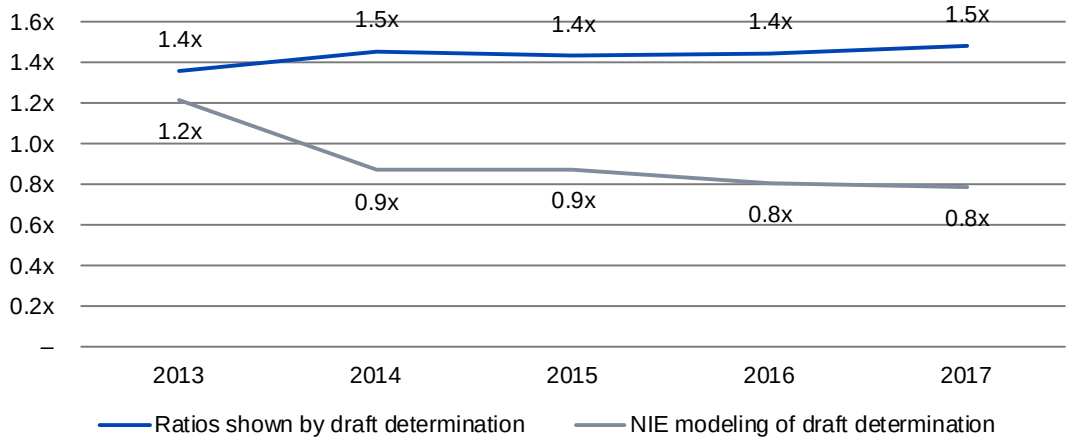
NIE's PMICR of 0.9x is based on NIE's modelling of the Draft Determination as set out below.

NIE financial profile

The Utility Regulator forecasts that under its Draft Determination PMICR is to be between 1.4x and 1.5x during the RP5 period. However, NIE's modelling of the assumptions, which we have reviewed and believe to be an accurate representation of how Fitch would calculate the key ratios, indicates that the key credit ratio PMICR will weaken significantly over the RP5 period. It should be noted that ratings are *prospective* judgements and the trajectory of credit ratios will be reflected in the credit rating.

The table below shows the PMICR shown in the Draft Determination and NIE's modelling of the Draft Determination.

Chart 2. PMICR ratios



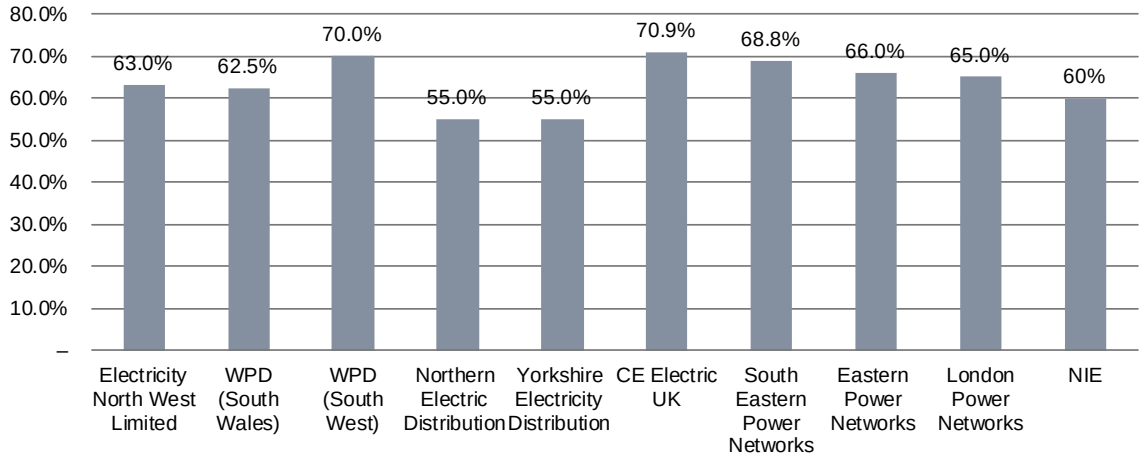
Source Utility Regulators Draft Determination and NIE

The outcome of NIE's modelling of the Draft Determination indicates a PMICR of less than 1.0x that approaches 0.8x towards the end of the RP5 period. Our conclusion from this outcome is that a projected PMICR at this level over a sustained period would place significant downward pressure on NIE's rating. Post the publication of the Draft Determination Fitch released a report which stated:

"Fitch's scenario analysis indicates that gearing is likely to increase towards a range of 50-60% and ***PMICR could range anywhere between 1.0-1.5x****, depending on applied assumptions. While the higher gearing would still be commensurate with a standalone 'BBB+' Long-term IDR for NIE, the* ***reduced PMICR in isolation indicates the lower end of investment-grade or even speculative grade ratings.****"*

NIE have modelled the outcome of the draft determination assuming a level of gearing in line with the parameters set out in the Utility Regulator's calculation of WACC. At this level of gearing NIE is below all but two of the other UK DNO's yet on a PMICR basis is significantly below all peers as shown in Chart 1. This would indicate to us that the allowed return in comparison to the regulatory asset base under the Draft Determination is low.

Chart 3. Net debt to RAB of DNO peers and NIE



Source Utility Regulators Draft Determination, NIE and Fitch

NIE business risk profile

In its Draft Determination the Utility Regulator correctly focused on PMICR as the key financial driver of NIE's credit rating. However, greater consideration needs to be given to the business risk profile of NIE and its effect on its credit rating.

The key driver of the credit rating of Regulated Network Utilities is the strength of the regulatory framework. Transparency and predictability are key to the rating agencies when evaluating the regulatory risk. Changes to price-setting mechanisms and application of unrealistic assumptions among other thing are considered detrimental to the transparency and predictability of the regulatory framework. Fitch states in its report untitled ""Rating EMEA Regulated Network Utilities-July 2010" that:

"Regulation is the main credit risk factor for a network utility;"

"Transparency and predictability are the pillars of the regulatory framework considered most beneficial to the credit profile of a regulated asset company. Regulatory risk increases as the framework becomes less transparent and predictable..... a track record of regulatory intervention, changes in price-setting mechanisms, recourse to exemption provisions, application of unrealistic

assumptions and efficiency standards, and windfall taxes, are all considered elements detrimental to the transparency and predictability of the regulatory framework."

NIE is the sole electricity DNO regulated by the Utility Regulator and any indication that the regulatory framework is not as strong as that of the other UK DNOs would impact credit ratings. Furthermore comments from rating agencies that imply a weaker regulatory environment and business risk profile will deter investors from investing in NIE bonds. Fitch in its report dated 20 May 2011 states that:

"The regulatory environment in Northern Ireland is less mature and transparent than that of Britain. There is also a somewhat higher risk of onerous decisions, due to the lack of direct peers for benchmarking."

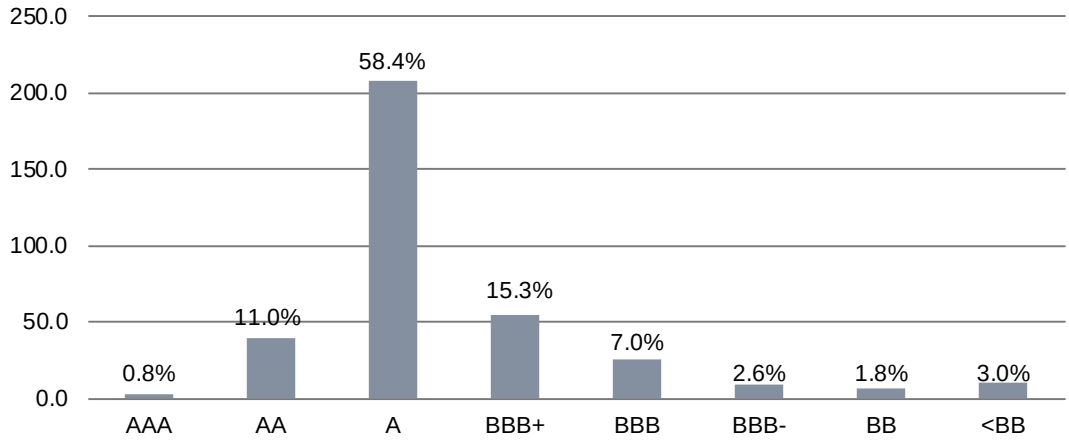
Under the Moody's rating grid non-financial factors including stability and predictability of the regulator regime, revenue risk, cost and investment recovery make up 40% of the weighting for the rating of regulated network utilities. Under the current Draft Determination all of these points would be weakened for NIE.

A credit rating below BBB+ would present significant financeability problems for NIE

NIE's debt market capacity will be significantly disadvantaged by a rating below BBB+

All other UK DNOs are rated at least BBB and the vast majority are rated BBB+ or higher. Accordingly, in the debt markets, a BBB rated NIE would be at the lower end of its DNO peer group. Further to this in the wider utilities sector 86% of issuance is rated BBB+ or higher. This is shown in the chart below.

Chart 4. Utility bond ratings mix (volume of issuance €bn last 7 years)



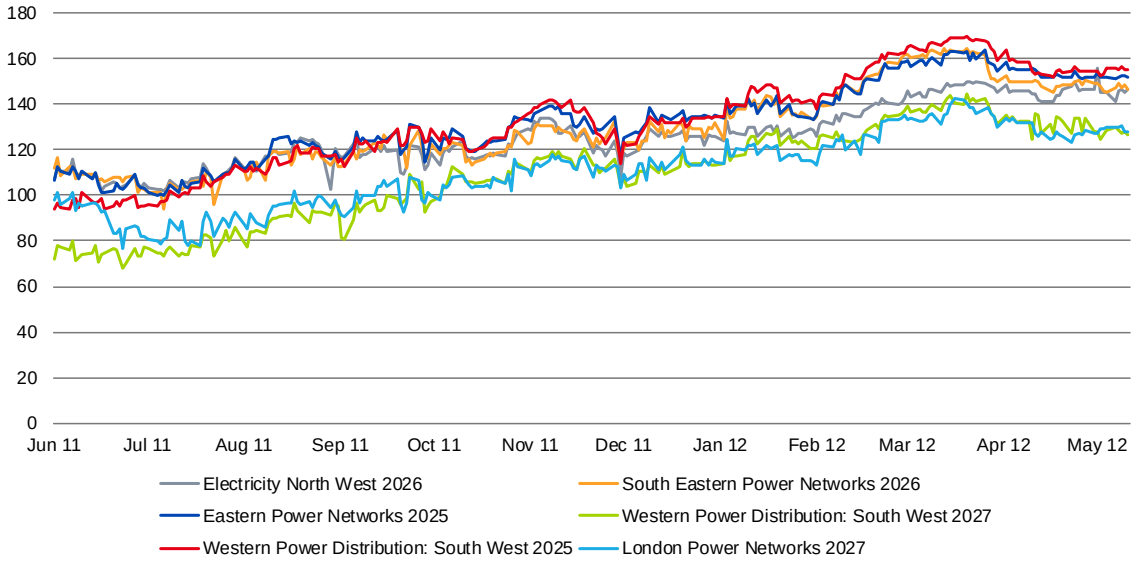
Source Dealogic

In addition, typically investors' fund allocation rules mean that the amount they can invest in a BBB rated bond is lower than the amount that can be invested in a bond that is rated A. Therefore, a rating below BBB+ rating would seriously limit the pool of capital that NIE could target when looking to raise funds in the capital markets. A rating below BBB+ will create significant difficulty for NIE and impact on its ability to raise debt at competitive rates in the market.

NIE's cost of funding in the markets is significantly higher than that of UK DNOs despite an equivalent rating which reflects the markets' perception of higher risk in NIE

NIE bonds currently trade at a significantly higher yield to other UK DNOs reflecting the perception of higher risk for NIE in the market. Any reduction in NIE's rating from BBB+ could put further pressure on pricing next time NIE is required to access bond markets. Over the past year NIE's 2026 bond has traded at a spread to benchmark on average 123bps over bonds of selected UK peers that have debt of comparable maturity as shown in Chart 5 below.

Chart 5. Spread premium of NIE bond versus selected UK peers (bps)



Source Datastream

Bank market capacity, including EIB appetite, is adversely affected by a rating below the BBB+ range, as banks have lower lending capacity and appetite for lower rated credits due to capital allocation rules.

A credit rating of BBB+ would ensure more consistent access to the debt markets

The debt markets have often been shut for a prolonged period during the financial crisis. However, corporates with a solid investment grade rating were able to access the market more consistently than those at the lower end of investment grade.

Key conclusions

We believe that under the current Draft Determination NIE could have significant issues financing its operations over the RP5 period

- NIE's rating analysis indicates that PMICR will fall to a level over the RP5 period which would create significant downward pressure on NIE's rating.

- Rating agencies and investors perceive the regulatory environment in Northern Ireland to be weaker than that in the rest of the UK and view the business risk of NIE as greater than its other UK peers. This is evidenced by commentary from Fitch and implied by the pricing of NIE's current bond. An outcome that would put significant pressure on NIE's financial performance could further erode investor confidence.
- At a rating of below BBB+, NIE will face significant difficulties in raising finance. Rated integrated utility companies are predominantly rated above A- across Europe and the vast majority of NIE's UK peers who are considered to be operating in a more stable and predictable regulatory environment are rated BBB+ or higher. Given the unique regulatory framework in NI, we believe that NIE ideally needs to be rated in-line or higher than UK peers to compete effectively for funds in the market.
- At a rating of below BBB+ NIE will have less reliable access to funds and at a higher cost. Furthermore if market volatility increases debt markets may shut, as has been the case in the past to issuers with a credit rating at the lower end of the BBB range.