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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APPENDIX 3A1

CRITIQUE OF CEPA’S BENCHMARKING OF NIE
Review of CEPA’s efficiency analysis

A REPORT PREPARED FOR NIE

June 2012
## Review of CEPA’s efficiency analysis

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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.

\(^1\) 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.

Summary
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. 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:

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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**

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

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 a 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.

Consequences for updating our 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

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>NIE “efficiency score</th>
<th>NIE “efficiency rank</th>
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</thead>
<tbody>
<tr>
<td>1 Base case in May 2011</td>
<td>90%</td>
<td>4</td>
</tr>
<tr>
<td>2 As 1 plus revised market opening costs</td>
<td>90%</td>
<td>4</td>
</tr>
<tr>
<td>3 As 2 excluding disallowed items (excess overtime and billing charges)</td>
<td>88%</td>
<td>3</td>
</tr>
<tr>
<td>4 As 3 with CEPA’s regional wage adjustment</td>
<td>93%</td>
<td>6</td>
</tr>
<tr>
<td>5 As 3 with revised regional wage adjustment</td>
<td>90%</td>
<td>3</td>
</tr>
</tbody>
</table>

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 contrast 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

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>NIE “efficiency score”</th>
<th>NIE “efficiency rank”</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Base case in May 2011 (using year 2010/11)</td>
<td>92%</td>
<td>4</td>
</tr>
<tr>
<td>2 As 1 plus market opening costs</td>
<td>92%</td>
<td>4</td>
</tr>
<tr>
<td>3 As 2 with CEPA’s regional wage adjustment</td>
<td>97%</td>
<td>7</td>
</tr>
<tr>
<td>4 As 2 with revised regional wage adjustment</td>
<td>93%</td>
<td>4</td>
</tr>
</tbody>
</table>

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.

---

### Table 4. Comparison of results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>NIE “efficiency score”</th>
<th>NIE “efficiency rank”</th>
<th>Upper quartile</th>
</tr>
</thead>
<tbody>
<tr>
<td>CEPA base case (CSV MEAV)</td>
<td>104%</td>
<td>9</td>
<td>90%</td>
</tr>
<tr>
<td>Updated benchmarking for 2009/10</td>
<td>90%</td>
<td>3</td>
<td>90%</td>
</tr>
<tr>
<td>(sensitivity 5 in Table 2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Updated benchmarking for 2010/11</td>
<td>93%</td>
<td>4</td>
<td>94%</td>
</tr>
<tr>
<td>(sensitivity 4 in Table 3)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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.
Frontier Economics Limited in Europe is a member of the Frontier Economics network, which consists of separate companies based in Europe (Brussels, Cologne, London & Madrid) and Australia (Brisbane, Melbourne & Sydney). The companies are independently owned, and legal commitments entered into by any one company do not impose any obligations on other companies in the network. All views expressed in this document are the views of Frontier Economics Limited.
APPENDIX 4A1

REVIEW OF THE UTILITY REGULATOR’S BOTTOM UP PROJECT ASSESSMENT
Appendix 4A1 contains extracts of material provided to NIE by the Utility Regulator that has not been made public. NIE has sought the Utility Regulator's approval to publish this appendix and will do so once that approval has been obtained.
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”
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.
Our estimates are based on a unit cost of £33.5k/km. However, we are aware that the Ofgem figure on an equivalent basis is in excess of £40k/km.

We think that the difference is primarily due to additional construction costs for items such as portable generation but mainly landowner compensation claims 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 compensation claims.

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 DRAFT

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 25mm² 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 25mm² 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
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).

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

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Specialist labour</td>
<td>2.1%</td>
<td>2.1%</td>
<td>2.1%</td>
<td>2.1%</td>
<td>2.1%</td>
</tr>
<tr>
<td>General labour</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
</tr>
<tr>
<td>Materials</td>
<td>0.7%</td>
<td>0.6%</td>
<td>0.6%</td>
<td>0.6%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Contractors</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
<td>1.4%</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>BAU capex</th>
<th>BAU opex</th>
</tr>
</thead>
<tbody>
<tr>
<td>Specialist labour</td>
<td>25.9%</td>
<td>68.3%</td>
</tr>
<tr>
<td>General labour</td>
<td>6.9%</td>
<td>18.2%</td>
</tr>
<tr>
<td>Materials</td>
<td>45.1%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Contractors</td>
<td>22.1%</td>
<td>6.3%</td>
</tr>
</tbody>
</table>

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>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>OBR March 2012</td>
<td>2.9%</td>
<td>2.3%</td>
<td>2.9%</td>
<td>3.8%</td>
<td>4.0%</td>
</tr>
<tr>
<td>forecast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>June 2011</td>
<td>3.4%</td>
<td>3.5%</td>
<td>3.6%</td>
<td>3.8%</td>
<td>3.2%</td>
</tr>
<tr>
<td>forecast (First Economics)</td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

**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

<table>
<thead>
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<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Average earnings</td>
<td>2.4%</td>
<td>3.5%</td>
<td>4.4%</td>
<td>4.5%</td>
<td>4.6%</td>
</tr>
<tr>
<td>RPI</td>
<td>2.9%</td>
<td>2.3%</td>
<td>2.9%</td>
<td>3.8%</td>
<td>4.0%</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>General labour</td>
<td>-0.5%</td>
<td>1.2%</td>
<td>1.5%</td>
<td>0.7%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Specialist labour</td>
<td>0.7%</td>
<td>2.4%</td>
<td>2.6%</td>
<td>1.9%</td>
<td>1.7%</td>
</tr>
</tbody>
</table>

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, \textit{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

<table>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrical materials price inflation forecast (First Economics)</td>
<td>5.0%</td>
<td>5.0%</td>
<td>5.0%</td>
<td>5.0%</td>
<td>5.0%</td>
</tr>
<tr>
<td>RPI</td>
<td>2.9%</td>
<td>2.3%</td>
<td>2.9%</td>
<td>3.8%</td>
<td>4.0%</td>
</tr>
<tr>
<td>Raw materials RPE</td>
<td>2.0%</td>
<td>2.6%</td>
<td>2.0%</td>
<td>1.2%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Specialist labour</td>
<td>0.7%</td>
<td>2.4%</td>
<td>2.6%</td>
<td>1.9%</td>
<td>1.7%</td>
</tr>
<tr>
<td>General labour</td>
<td>-0.5%</td>
<td>1.2%</td>
<td>1.5%</td>
<td>0.7%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Materials</td>
<td>2.0%</td>
<td>2.6%</td>
<td>2.0%</td>
<td>1.2%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Contractors</td>
<td>0.1%</td>
<td>1.8%</td>
<td>2.0%</td>
<td>1.3%</td>
<td>1.2%</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th></th>
<th>BAU capex</th>
<th>BAU opex</th>
</tr>
</thead>
<tbody>
<tr>
<td>Specialist labour</td>
<td>27.2%</td>
<td>71.8%</td>
</tr>
<tr>
<td>General labour</td>
<td>5.6%</td>
<td>14.7%</td>
</tr>
<tr>
<td>Materials</td>
<td>45.1%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Contractors</td>
<td>22.1%</td>
<td>6.3%</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Input</th>
<th>Capex</th>
<th>Opex</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Specialist labour</td>
<td>£9.6m</td>
<td>£4.2m</td>
<td>£13.8m</td>
</tr>
<tr>
<td>General labour</td>
<td>£0.6m</td>
<td>£0.3m</td>
<td>£0.9m</td>
</tr>
<tr>
<td>Materials</td>
<td>£42.8m</td>
<td>£4.0m</td>
<td>£46.8m</td>
</tr>
<tr>
<td>Contractors</td>
<td>£5.1m</td>
<td>£0.2m</td>
<td>£5.4m</td>
</tr>
<tr>
<td>Total</td>
<td>£58.1m</td>
<td>£8.7m</td>
<td>£66.8m</td>
</tr>
</tbody>
</table>
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
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

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 so². 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

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\(^3\) 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 Determination⁴, 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 asymmetrical⁵ 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 submission⁶, 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 suggests⁷ 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

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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.
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 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.

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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 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:

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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

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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:

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\(^{13}\) 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\textsuperscript{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.

\textsuperscript{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\(^{17}\),

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\(^{15}\) 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.

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\(^{18}\) 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

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NIE’s cost of capital at RP5

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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.
Executive Summary

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**

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

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 our 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’s DPCR5 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

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.
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:

> “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**

As shown above, the current measure of the 10-year trailing average is approximately 3.0%.

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Evaluation of the Utility Regulator’s draft proposals and latest market evidence
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”.

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 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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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**

<table>
<thead>
<tr>
<th>Issuer</th>
<th>Issuance year</th>
<th>Maturity date</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>NIE</td>
<td>2011</td>
<td>02/06/2026</td>
<td>BBB+</td>
</tr>
<tr>
<td>Eastern Power Networks</td>
<td>1995</td>
<td>31/03/2025</td>
<td>BBB+</td>
</tr>
<tr>
<td>Electricity North West</td>
<td>1995</td>
<td>25/03/2026</td>
<td>BBB+</td>
</tr>
<tr>
<td>London Power Networks</td>
<td>2002</td>
<td>07/06/2027</td>
<td>BBB+</td>
</tr>
<tr>
<td>South Eastern Power Networks</td>
<td>2003</td>
<td>05/06/2026</td>
<td>BBB+</td>
</tr>
<tr>
<td>Western Power Distribution: South West</td>
<td>2010</td>
<td>09/05/2025</td>
<td>BBB</td>
</tr>
<tr>
<td>Western Power Distribution: South West</td>
<td>2003</td>
<td>25/03/2027</td>
<td>BBB</td>
</tr>
</tbody>
</table>

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.
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

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\(^5\) 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

<table>
<thead>
<tr>
<th>Issuer</th>
<th>Issuance year</th>
<th>Maturity date</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phoenix Gas</td>
<td>2009</td>
<td>10/07/2017</td>
<td>Baa2</td>
</tr>
<tr>
<td>Wales and Western Utilities (gas)</td>
<td>2009</td>
<td>02/12/2016</td>
<td>Baa1</td>
</tr>
<tr>
<td>Southern Gas Networks (gas)</td>
<td>2009</td>
<td>02/11/2018</td>
<td>BBB</td>
</tr>
<tr>
<td>Northern Gas Networks (gas)</td>
<td>2009</td>
<td>08/07/2019</td>
<td>BBB+</td>
</tr>
<tr>
<td>Northumbrian Water (water)</td>
<td>2001</td>
<td>11/10/2017</td>
<td>BBB+</td>
</tr>
<tr>
<td>United Utilities Water (water)</td>
<td>2003</td>
<td>14/05/2018</td>
<td>BBB+</td>
</tr>
</tbody>
</table>

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).

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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.
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%. 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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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. 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. 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). 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%.

**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
to 7.2%. 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**

![Equity Risk Premium Chart](chart)


(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. 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%.

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Figure 7. Recent survey evidence on the ERP for the UK

![Survey evidence on ERP for the UK](chart.png)


Summary of evidence

Table 3 summarises this evidence.
Table 3. Market evidence on UK equity market returns and ERP

<table>
<thead>
<tr>
<th>Source</th>
<th>Estimate of market equity returns</th>
<th>Estimate of ERP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dimson, Marsh and Staunton historic returns, 2012, arithmetic average of UK returns measured between 1900 and 2011</td>
<td>7.1%</td>
<td>5.0%</td>
</tr>
<tr>
<td>Bank of England, DGM estimate, December 2011 most recent estimates, and range defined by high and low measured over past four years</td>
<td>9.2%*</td>
<td>Latest estimate: 7.2% Over past four years: 3.4% (min) to 7.6% (max) Average: 5.5%</td>
</tr>
<tr>
<td>Fernández, Aguirreamalloa and Corres survey, May 2011, using responses of UK financial academics, analysts and company executives</td>
<td>6.9% to 7.6%**</td>
<td>4.9% to 5.6% Average: 5.3%</td>
</tr>
</tbody>
</table>


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:

"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 proposals and latest market evidence.
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:

“1.7. The total cost 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.\(^\text{17}\) 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:

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. 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. 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 of equity of at least 109 bps. A more conservative approach would be to consider a cost of equity uplift of at least 62 bps.

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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

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

Source: Frontier calculations

Note: * Assumes asset beta of 0.42, debt beta of 0.1 and gearing of 60%.
Frontier Economics Limited in Europe is a member of the Frontier Economics network, which consists of separate companies based in Europe (Brussels, Cologne, London & Madrid) and Australia (Brisbane, Melbourne & Sydney). The companies are independently owned, and legal commitments entered into by any one company do not impose any obligations on other companies in the network. All views expressed in this document are the views of Frontier Economics Limited.
APPENDIX 16A1

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.

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**Chart 1. PMICR ratio and rating for selected rated peers**

<table>
<thead>
<tr>
<th>PMICR</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.5x</td>
<td>BB+</td>
</tr>
<tr>
<td>2.0x</td>
<td>BBB+</td>
</tr>
<tr>
<td>1.5x</td>
<td>BBB</td>
</tr>
<tr>
<td>1.0x</td>
<td>BBB-</td>
</tr>
<tr>
<td>0.5x</td>
<td>BB+</td>
</tr>
</tbody>
</table>

**Source** Fitch, Utility Regulators Draft Determination and NIE

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1We 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 are 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.

<table>
<thead>
<tr>
<th>Chart 2. PMICR ratios</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
</tr>
<tr>
<td>Ratios shown by draft determination</td>
</tr>
<tr>
<td>1.6x</td>
</tr>
<tr>
<td>1.4x</td>
</tr>
<tr>
<td>1.2x</td>
</tr>
<tr>
<td>0.6x</td>
</tr>
<tr>
<td>0.2x</td>
</tr>
</tbody>
</table>

**Source** Utility Regulator 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

<table>
<thead>
<tr>
<th></th>
<th>Electricity North West Limited</th>
<th>WPD (South Wales)</th>
<th>WPD (South West)</th>
<th>Northern Electric Distribution</th>
<th>Yorkshire Electricity Distribution</th>
<th>CE Electric UK</th>
<th>South Eastern Power Networks</th>
<th>Eastern Power Networks</th>
<th>London Power Networks</th>
<th>NIE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net debt to RAB</td>
<td>63.0%</td>
<td>62.5%</td>
<td>70.0%</td>
<td>65.0%</td>
<td>55.0%</td>
<td>70.9%</td>
<td>68.8%</td>
<td>66.0%</td>
<td>66.0%</td>
<td>60%</td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Chart 4. Utility bond ratings mix (volume of issuance €bn last 7 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250.0</td>
</tr>
<tr>
<td>200.0</td>
</tr>
<tr>
<td>150.0</td>
</tr>
<tr>
<td>100.0</td>
</tr>
<tr>
<td>50.0</td>
</tr>
<tr>
<td>0.0</td>
</tr>
<tr>
<td>AAA</td>
</tr>
<tr>
<td>0.8%</td>
</tr>
</tbody>
</table>

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)

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.