# COSTS OF A BEST NEW ENTRANT PEAKING PLANT FOR THE CALENDAR YEAR 2013

## A REPORT FOR THE REGULATORY AUTHORITIES

May 2012

**Initial report**

**FOR PUBLICATION**

Submitted by:

**Cambridge Economic Policy Associates Ltd in association with Parsons Brinkerhoff**

CEPA

125 YEARS

# CONTENTS

# 1. INTRODUCTION AND CONTEXT

## 1.1. Overview

Cambridge Economic Policy Associates (CEPA), working with Parsons Brinkerhoff (PB), is pleased to submit this initial report on the costs of a Best New Entrant (BNE) peaking plant for the calendar year 2013 to the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), collectively the Regulatory Authorities (RAs).

## 1.2. Purpose of the initial report

This independent report provides CEPA and PB's estimate of the fixed costs that a rational investor would incur in constructing and operating a peaking plant to enter the Single Electricity Market (SEM) in 2013. The purpose of the report is to inform the RA's determination of the size of the capacity payment pot for the SEM trading year 2013.

This report sets out the approach which CEPA and PB have taken to determining costs and outlines all assumptions made. To the fullest extent possible, CEPA and PB have sought to consistently apply the methodology used to determine the fixed costs of a peaking plant for the 2010, 2011 and 2012 trading years.

This report is intended to inform the RA's consultation on the BNE price for 2013. CEPA and PB would welcome views from market participants on the issues raised. In particular, we would welcome evidence to support comments about the validity of costs or current market conditions. CEPA and PB will carefully consider all comments and evidence received from stakeholders and, will, where appropriate, reflect these comments and evidence in an updated report.

## 1.3. CEPA and Parsons Brinkerhoff

This report has been developed jointly by CEPA and PB.

CEPA is a London based economic and finance advisory firm with a leading economic regulation and power sector practice. CEPA's staff and associates have extensive experience in analysing regulatory policy and its impacts on stakeholders, power generation investment appraisal, assessing the cost of capital, developing generation tariffs and tariff methodologies and advising on relevant incentive issues. CEPA has significant experience of successfully delivering projects for the RAs and for private and public sector clients in the UK, Europe and internationally.

PB is an internationally renowned engineering and programme management firm offering a multidisciplinary consultancy service in transportation, buildings, power and telecommunications. Established in 1885, PB employs more than 12,000 staff in over 250 corporate and project offices worldwide. Previously operating as PB Power, the company has extensive experience of power generation, pricing and tariffs and has considerable experience of advising regulatory bodies. PB has worked previously with the RAs, as well as with CEPA.

CEPA, in association with PB, advised the RAs in the calculation of the fixed cost of a BNE plant for the 2010, 2011 and 2012 trading years.

## 1.4. The capacity payment mechanism

### 1.4.1. Objectives of the capacity payment mechanism

The capacity payment is an important part of the SEM. The RAs introduced a Capacity Payment Mechanism (CPM) in order to fulfil the objectives outlined in Box 1.1.

**Box 1.1: Objectives of the Capacity Payment Mechanism**

- **Capacity Adequacy/ Reliability of the system** - The CPM must encourage both the construction and maintained availability of capacity in the SEM. Security of the system, will be the core feature of the CPM.
- **Price Stability** - The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market
- **Simplicity** - The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism could reduce investor confidence in the market and increase implementation costs.
- **Efficient price signals for Long Term Investments** - In theory it would be possible to incentivise vast amounts of capacity over and above that necessary for system security in the SEM, although the cost of implementing such a scheme may be unacceptable to customers. The CPM should meet the criterion in this section at the lowest reasonable cost. Revenues earned by generators should still efficiently signal appropriate market entry and exit.
- **Susceptibility to Gaming** - The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties.
- **Fairness** - The CPM should not unfairly discriminate between participants. An appropriate CPM will maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

*Source: Regulatory Authorities / CEPA*

The CPM is fixed on an annual basis, with shorter duration "capacity periods" reflecting that the same quantity of generation is not necessarily available at all times of the year.

The CPM requires two key features:

- a Capacity Requirement which was 6,826 MW for 2010, 6,922 MW for 2011 and 6,918 MW for 2012; and
- a price element which was €80.74/kW/year for 2010, €78.73/kW/year for 2011 and €76.34/kW/year for 2012.

The product of these price and quantity elements yielded an Annual Capacity Payment Sum (ACPS) for the 2012 trading year of €528,120,120.

### 1.5. Structure of this document

The remainder of this document is structured as follows:

- Section 2 discusses the key concepts involved in estimating the costs of a BNE plant and outlines CEPA/PB's methodology.
- Section 3 provides details of the approach used to determine the appropriate BNE technology option.
- In Section 4 we consider the costs associated with the chosen BNE technology option.
- Section 5 sets out financial considerations, including our estimate of the cost of capital required by an investor in a BNE plant.
- Section 6 provides details of the infra-marginal rent and ancillary service revenues the plant could be expected to earn through operation in the energy market.
- Section 7 sets out our initial estimate of the BNE price based on the assumptions set out in the remainder of the document.

The document also includes two annexes:

- Annex 1 shows the filtering process which CEPA/PB used to reduce the long list of technology options.
- Annex 2 provides a more detailed assessment of relevant financial issues.
- Annex 3 discusses some of the arguments raised and points that might be considered concerning a single WACC for the SEM.

## 2. OVERVIEW OF CEPA/PB'S APPROACH

This section sets out the approach which CEPA/PB have taken to determining the costs a BNE peaking plant. As this is the fourth year for which CEPA/PB have been commissioned to determine the costs of a BNE peaking plant, we have employed a substantively similar approach as in the previous three trading years (2010, 2011 and 2012). However, we have sought to fully reflect comments received from respondents if deemed appropriate and lessons learned from previous calculations as well as revisiting and refreshing our analysis in light of recent market developments.

### 2.1. Medium Term Review

CEPA/PB are aware that the RAs recently concluded their Medium Term Review (MTR) of the CPM. The main purpose of this review was to examine if the current design of the CPM could be further improved to optimally meet the objectives of the CPM (see Box 1.1 above). The RAs decision document[1] has concluded that the current CPM is generally working well and that there is no compelling need to make major changes to the current CPM design and methodology including the BNE calculation methodology.

While certain outputs of the MTR will affect the BNE price for the forthcoming trading year, including that infra marginal rent will be deducted from the BNE 2013 Peaker Cost (€/kW/yr) and the BNE price will be fixed in 2013 and indexed in subsequent calendar years, CEPA and PB have largely been appointed to determine the fixed costs of a BNE peaking plant by applying a methodology which is consistent with that used in previous years.

### 2.2. BNE calculation

The BNE calculation is designed to determine the costs that a rational investor in a peaking plant which served the final mega watt (MW) of demand would incur at the point when the market is in equilibrium. It is therefore a theoretical exercise based around assumptions about the behaviour of a rational investor in a notional plant. However, in practice it is not sensible to consider BNE costs in a purely theoretical manner. Therefore, whilst one is dealing with a notional plant, it is necessary, to the extent practicable, to develop cost estimates with reference to market evidence.

#### 2.2.1. Questions to consider in determining BNE costs

While the BNE calculation requires the estimation of a significant number of costs and revenues, at the highest-level it requires a series of relatively simple questions to be addressed. These questions relate to the characteristics of a rational investor in peaking capacity, the decisions that the investor would take and the costs they would incur in bringing a faced plant to market in 2013.

[1] http://www.allislandproject.org/GetAttachment.aspx?id=23ad7d27-1543-4f69-bba0-8806238dd8d8

The high-level questions and a number of the more detailed issues they give rise to are summarised in Table 2.1 below.

*Table 2.1: High level questions to address*

| Key question | Other issues / questions to consider |
|---|---|
| What are the characteristics of a rational investor? | What type of investor is willing to invest in this asset class?<br>Is the investor independent or vertically integrated?<br>Are they considering opportunities across the World, Europe or solely Ireland/ UK?<br>How would they finance an investment in a BNE plant? |
| What technology choice would the rational investor make? | What size is the plant?<br>What specification (due to operational or environmental factors) does the plant have to meet?<br>What trade-offs between efficiency and cost would they make?<br>Which plant would they opt for and how much would that cost? |
| What would be the rational location for a new peaking plant? | Where can the plant be located?<br>What does that mean for fixed costs?<br>What does this mean for operational costs? |
| Why would a BNE choose to enter the SEM? | Capacity payment revenues?<br>Infra-marginal rent and ancillary services revenues?<br>What is the required cost of capital? |

### 2.2.2. BNE methodology

The 2013 calculation will be the sixth time that the RAs have calculated the fixed costs of a BNE plant entering the SEM. In each instance that the calculation has been undertaken, a number of the features of the methodology have remained the same. These are:

- The costs of a peaking plant will be established for a site in Northern Ireland (NI) and a site in the Republic of Ireland (RoI) and infra-marginal rent and ancillary services number deducted from that figure.
- Infra-marginal rents earned by a given plant will not be a determinant of the choice of plant (i.e. they will be calculated independently of plant selection).
- The costs of a BNE plant will be calculated for both markets and a decision as to which is best made on cost-benefit grounds.

## 2.3. Approach

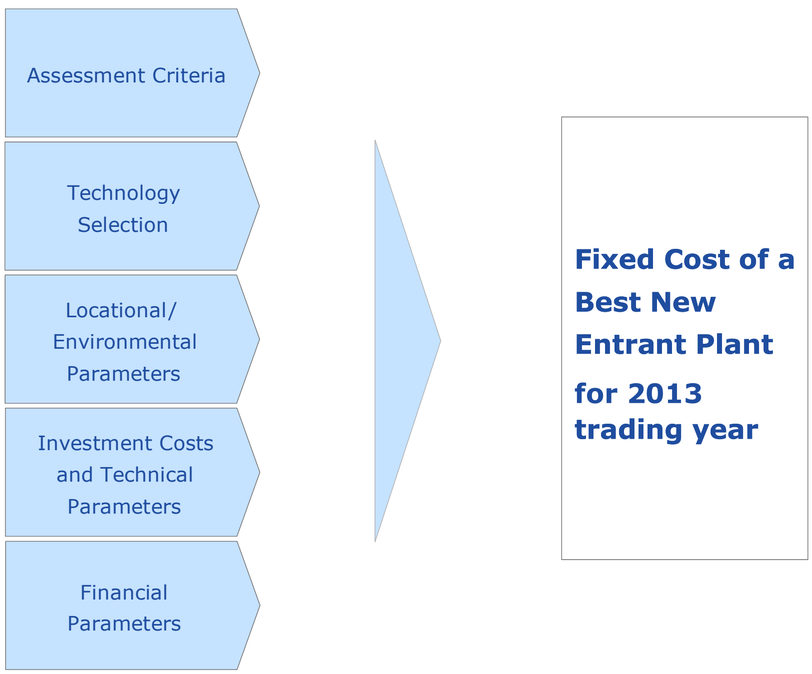
CEPA/PB are aware of the importance of the CPM to existing and prospective investors in generation and the consequences of the size of the CPM pot (the BNE price multiplied by the capacity requirement) for consumers. Our approach is consistent with that used in calculating the BNE price for the trading year 2010, 2011 and 2012.

The characteristics of the BNE plant for which costs are being derived are:

- The plant is notional and will be delivered into the market in the 2013 trading year. It may be located in either the RoI or NI and use the plant and fuel type which proves most cost efficient.
- The plant will serve the final megawatt of demand, hence it would be expected to operate for a very small proportion of the time (likely to be between 2% and 5%).

Undertaking the BNE calculation requires a series of issues to be addressed sequentially, before those elements are combined to develop a series of cost estimates. The high-level approach is shown in Figure 2.1 below.

*Figure 2.1: Stylised representation of the elements of the BNE calculation*




Our approach, in common with that used in previous years, has been to identify the most suitable technology option and then to calculate the costs of locating that plant at an appropriate site in both NI and the RoI. This then allows two Net Present Value (NPV) calculations to be undertaken and the most cost-effective location to be identified. Within this high-level approach, there are a series of important building blocks.

- The technology choice.
- Associated Engineering, Procurement and Construction (EPC) costs.
- Pre-financial close and other soft costs.
- Financing costs.

These issues are explored in subsequent sections.

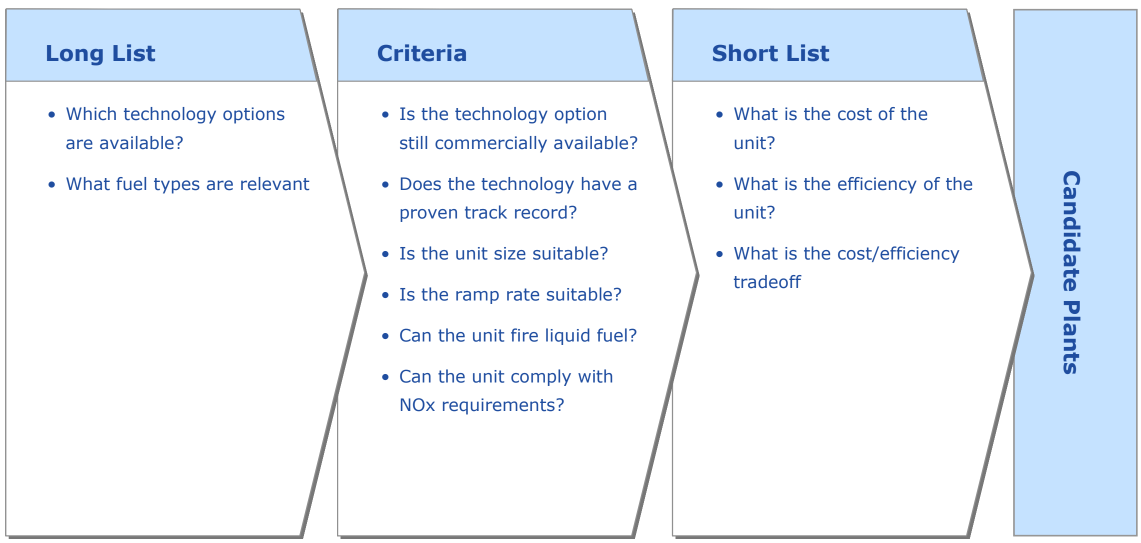
## 3. BNE TECHNOLOGY SELECTION

This section outlines the process that CEPA and PB have gone through to identify the series of options to be considered as part of the initial "long-list" of candidate plant, the criteria that have been used to filter this list towards a "short-list" and the considerations that have led to our final technology choice. Annex 1 provides a more detailed overview of the technology selection process.

### 3.1. Approach

The approach used to reduce a long-list of options to a short-list is shown in Figure 3.1 below. More detailed explanations are included in the subsections which follow.

*Figure 3.1: Approach to identifying technology options*




### 3.2. Long list of options

The starting point for our technology selection process is to develop a long-list of options capturing all available technology options which might reasonably be described as a peaking plant. The relevant plants from this list have been included in Annex 1, which is intended to cover the product offerings of the major original equipment manufacturers. The development of the long list for 2013 has drawn from the conclusions previously reached through the 2012, 2011 and 2010 CPM consultation process. Consequently, the following peaking options were not considered for the short-listing process:

- Second-hand plants.
- Interconnectors.
- Aggregated Generating Units.

Additionally, regarding pumped storage schemes (and similarly for compressed air energy storage schemes), for the 2011 calculation these dropped out of the short-listing process on cost. In practice, this is always likely to be the case since their inherent operational principle is to run cyclically and thus not "pitched" at serving the final megawatt, and have not been considered for this calculation.

### 3.2.1. Fuel choice

In the years prior to 2009, the RAs determined that the BNE peaking plant would run on distillate only. The decision was largely due to the costs associated with booking gas capacity and a perceived lack of gas market liquidity.

It was decided that for 2010, GTs under consideration would be evaluated both for distillate firing and for natural gas operation with dual-fuel capability. This decision was driven by a number of factors, including comments received from respondents to the 2010 consultation process and the views expressed by parties which attended a stakeholder seminar, that further developments in the gas market meant gas was a credible fuel source. In particular parties noted that there are several shorter-term products available (noting that a rational investor may not necessarily wish to use such products) in the RoI and there does not appear to be a scarcity of capacity. However parties noted that only an interruptible product exists in NI.

Consistent with the previous calculations we have considered candidate plant firing both natural gas (with distillate back-up) and distillate fuel only.

### 3.2.2. Environmental requirements

In considering the appropriate choice of technology, we have been mindful of the environmental requirements which a plant would need to meet. The chosen technology needs to be capable of meeting emissions requirements, and since all the potential candidate plant options in the long list are GTs firing low-sulphur fuels, this implies meeting the limits on oxides of nitrogen (NOx) and carbon monoxide.

The Directive on industrial emissions[2] (integrated pollution prevention and control - the Industrial Emissions Directive or IED) came into force on 6 January 2011. Article 30 of the Directive relates to 'Emissions Limit Values'. For 'New Plant' (i.e. those granted a permit after 7 January 2013), the Emission Limit Values are specified under Part 2 of Annex V.

The Emission Limit Values for gas turbines (including Combined Cycle Gas Turbines (CCGT)) are shown in Table 3.1 below.

[2] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control)

*Table 3.1: Emissions limits*

| Fuel Type | Maximum NOx value ($mg/Nm^3$) | Maximum CO value ($mg/Nm^3$) |
|---|---|---|
| Light and Middle Distillates as Liquid Fuels | 50 | 100 |
| Gas* | 50** | 100 |

*Source: Directive on industrial emissions*

* For gas turbines (including CCGT) the NOx and CO emission limit values set out apply only above 70 per cent load.

** For simple cycle gas turbines having an efficiency greater than 35% - determined at ISO base load conditions – the emission limit value for NOx shall be $50x\eta/35$, where $\eta$ is the gas turbine efficiency at base load conditions expressed as a percentage.

However, it should be noted that gas turbines for emergency use that operate less than 500 operating hours per year are not covered by the Emissions Limit Values noted above. In these cases, the operators of these gas turbine shall record the used operating hours. Since, as will be discussed in the later sections of this report, this assessment is based on a plant factor of no greater than 5 per cent (438 hours), then these units are not covered by the IED.

### 3.2.3. Short-listing criteria

Having developed an extensive long-list that covers various technology options and fuel types, we have then applied a series of short-listing criteria. These criteria are designed to reflect considerations which a rational investor may consider in making a decision on technology as well as the requirements of the Transmission System Operators (TSOs).

CEPA and PB consider that the assessment criteria used in last year's calculation remain fit-for-purpose. The RA's sought and received confirmation from the TSOs that this was the case, and we have therefore undertaken our initial short-listing by applying the pass/fail criterion set out in Table 3.2 below.

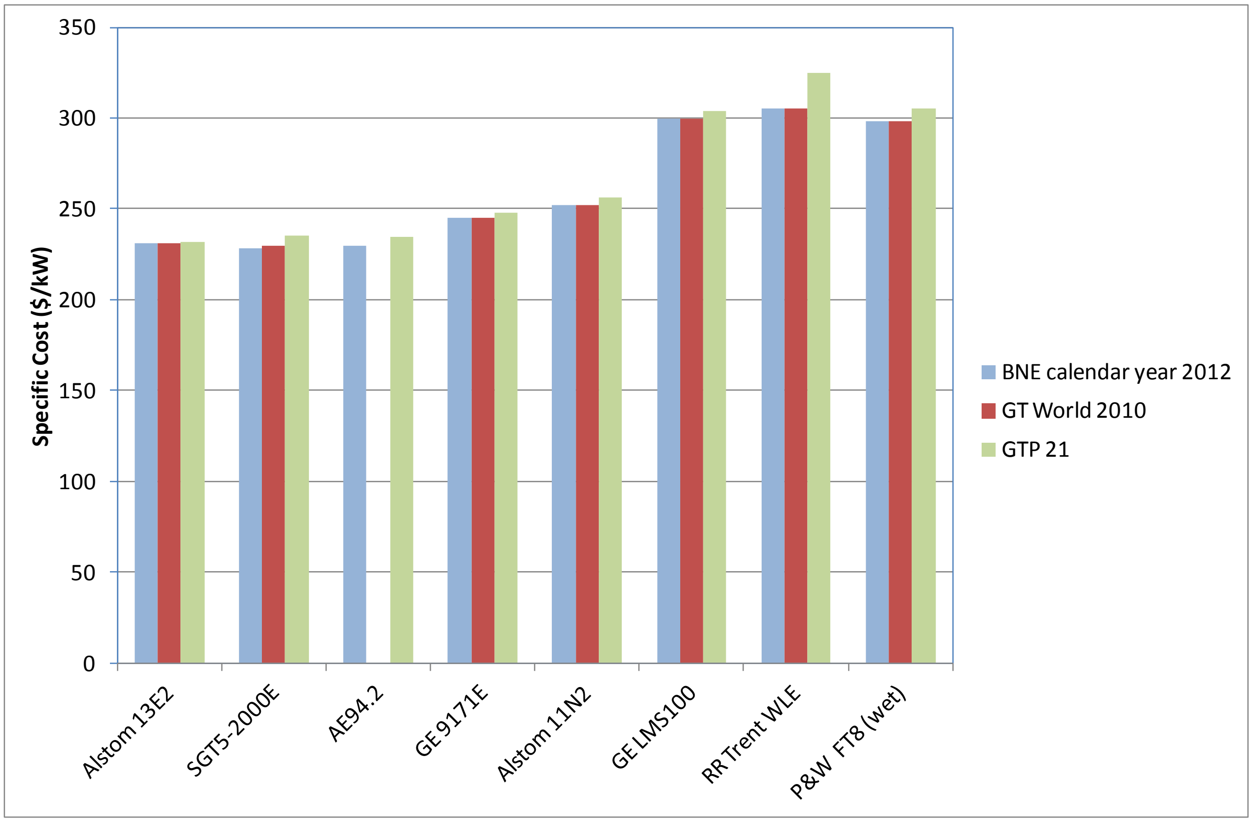
*Table 3.2: Filter criteria*

| Pass/fail criterion | Rationale |
|---|---|
| Is the technology option still commercially available? | The plant needs to be being manufactured to be credible. We have verified whether this is the case by contacting manufacturers. |
| Does the technology have a proven track-record (typically defined as 3 examples of over 8,000 running hours for industrial units or 500 starts for aero derivatives)? | While this is a proxy for the view that an insurer would take of a plant, we note that in 2010 we included an additional plant based on market feedback. |
| Are the unit sizes between 30 and 200MW? | This was the plant size which the TSOs historically deemed appropriate. The TSOs did not suggest a change to this assumption. |
| Can the technology option ramp up to full load in less than 20 minutes? | The TSOs identified this as a necessary operational criteria for a peaker. We note views that this time may need to fall as wind penetration rises but note that the TSOs did not suggest a change was appropriate. |
| Can the technology option fire liquid fuel? | RoI has an obligation on gas fired power stations to provide secondary fuel for backup. If gas fired the peaker would need to be capable of meeting this obligation. |
| Can it meet NOx requirements? | As noted above, the plant must be capable of meeting environmental legislation which is reflective of its expected pattern of operation. |

## 3.3. Initial filter

On the basis of the filtering process outlined above, we identified a series of plant which fulfilled these criteria. In our previous year (BNE 2012) report, we then considered the remaining options' equipment cost, as published in the Gas Turbine World 2010 GTW Handbook (an internationally recognised plant cost database), as a broad secondary filter. Ideally, as a direct comparison the 2011 edition of the GTW Handbook would be used, but this is not yet available. Instead, the basic gas turbine costs from the latest version of GT Pro (version 21), were used. These costs are the basis for the PEACE costs described in Section 3.4.2, and are generally in line with GTW Handbook specific costs. These costs are shown in Figure 3.2 below, with those used in the report for the 2012 trading year, and those given in GTW 2010.

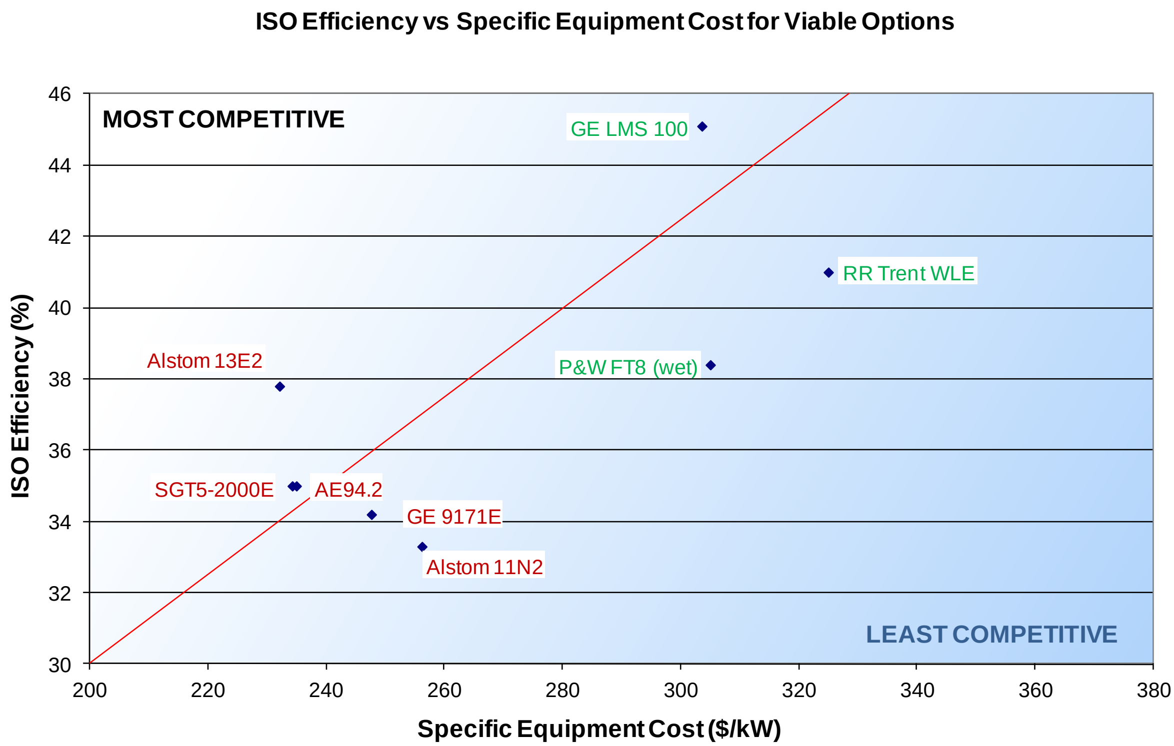
*Figure 3.2: Basic specific cost of viable options*




We note that during the BNE consultation process for the 2010 trading year calculation, feedback from generators indicated that given that the peaking plant would only be expected to run a small number of hours (2% to 5%), the capital cost would be a much more relevant consideration for an investor than the plant's efficiency. We agree with this comment and this was reflected it in the approach taken in short-listing plant for the 2012 trading year, and the same philosophy has been used for the 2013 trading year.

The diagram below shows the cost and efficiency trade-off for various potential candidate plants.

*Figure 3.3: ISO efficiency and equipment cost trade-off for front-running plant meeting filtering criteria*




The plot illustrates the fairly significant number of options which passed our initial sift. However, it also illustrates that there is, broadly speaking, a frontier of plants which represent the most likely candidates for the BNE plant given the reduced focus on efficiency. Plants above the line in the diagram would be expected to be the most likely candidates to become the BNE plant that serves the final megawatt. However, as discussed below, more efficient aero-derivative GTs shown in Figure 3.3 were considered in the candidate plant selection process.

### 3.3.1. Candidate plants

The candidate GTs for the 2012 trading year were:

- 1 x Siemens SGT5-2000E
- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2
- 3 x Pratt & Whitney SwiftPac 60 (wet) (FT8)
- 2 x General Electric LMS100PA

Although the position and slope of the dividing line between most competitive and least competitive plant will depend on relative cost, efficiency, fuel price, capacity factor etc, it gives a reasonable graphical representation of the demarcation. The GE 9171E and Alstom 11N2 are significantly more expensive and less efficient than the other industrial type units (SGT-2000E, AE94.2, Alstom 13E2) and so are still discounted. Similarly, with the aero-derivative GTs, the Trent is not included because the LMS100 is cheaper and more efficient. The P&W SwiftPac 60, although it appears less competitive than the LMS100, is included, as there are units installed in ROI and both the P&W SwiftPac 60 and the GE LMS100PA appear to be being actively considered by investors in the SEM.

In last year's modelling we included the increase in power output resulting from the use of water injection in the GT13E2, for which the power augmentation is greater than for the AE94.2 and the SGT5-2000E. This mode of operation, while reducing the efficiency, provides a greater power output (this was explained in an annex to the BNE 2010 decision document). The AE94.2/SGT5-2000E combustion system cannot operate with water injection while running on gas; however, the GT13E2 can benefit from water injection for power augmentation on gas operation and this has been included in the modelling.

We also included as part of last year's methodology, an opportunity for all of the OEMs of candidate plant the opportunity to provide the results of their own in-house performance simulations for the conditions established as the basis. Generally, there was excellent agreement between the Thermoflow results and those from the OEMs; only in the case of the SGT5-2000E, where a known limitation on the power output in GT PRO existed, did the results differ significantly. Although GT Pro has introduced a new "curve fit" model based on Siemens own SIPEP program, it still includes a power limit, not reflected by Siemens own performance data. The values provided by Siemens were therefore used again in this case and they closely resembled the results for the similar AE94.2.

We then proceeded to conduct a more detailed assessment of the costs of each of the candidate plants.

## 3.4. EPC costs and performance

This section briefly considers changes in EPC market conditions and outlines our approach to EPC cost estimation.

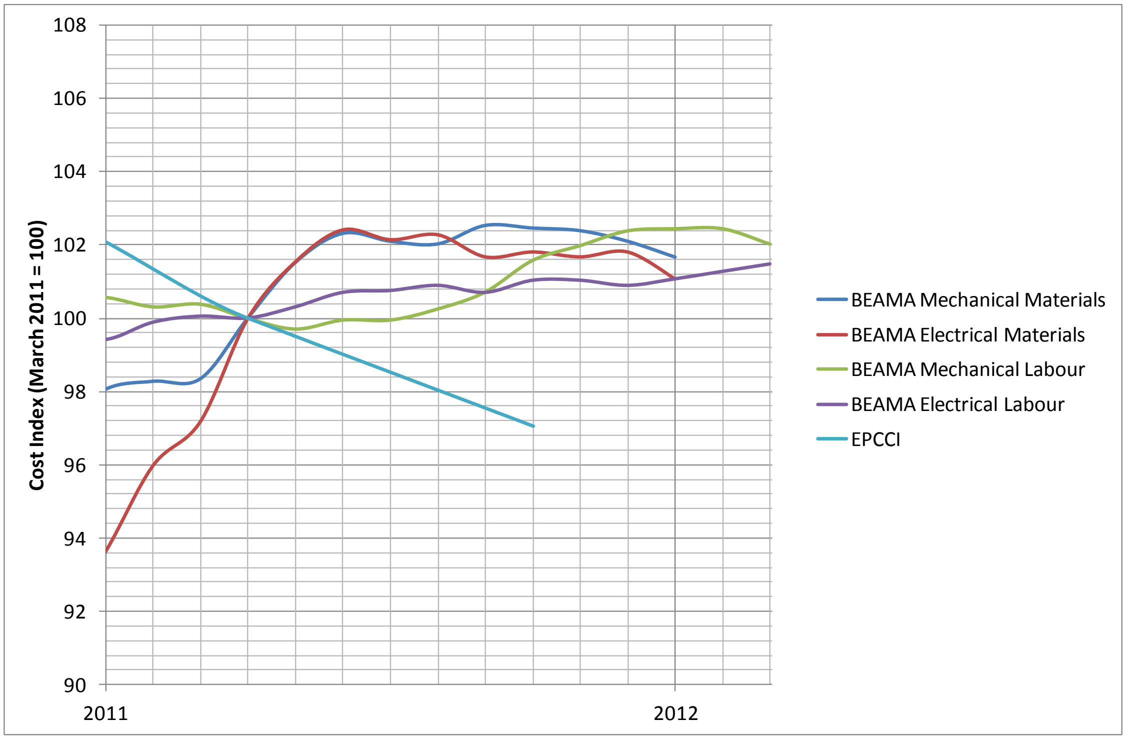
### 3.4.1. State of the EPC market

After a period of steady reduction over the last three or four years, we have witnessed a levelling out in the level of tendered EPC prices. Figure 3.4, below, shows material and labour cost indices from BEAMA (British Electrical and Allied Manufacturers' Association), and the European Power Capital Cost Index (EPCCI) (non nuclear)[3] , each adjusted to give March 2011 = 100. Although the BEAMA cost index reflects only UK costs, it does give an indication that costs over the last 12 months have increased by approximately 2 per cent. However, the addition of unpredictable sources of power generation such as wind power has increased developers' interests away from large CCGT

[3] IHS Indexes

plant toward smaller simple cycle plant, so the cost simple cycle plant may rise at a higher rate than CCGT, particularly with aero-derivative gas turbines.

*Figure 3.4: Material, labour and cost indices 2011*




### 3.4.2. Approach to EPC cost estimation

As in previous years, our approach to EPC cost estimation includes two elements:

- Modelling the shortlisted plants in GT PRO.
- Adjusting (where necessary) the resulting cost estimates to reflect current market conditions across a series of factors based on project cost data from PB's extensive project experience.

These two elements are discussed below.

*Calculation of adjustment factors for EPC estimates*

PB has worked on a significant number of projects which provide relevant comparators for the BNE peaking plant. As such, it has developed a significant data set which can be used to cross-check the results arising from software packages such as GT Pro when used in collaboration with its cost-estimating tool PEACE. PB therefore uses relevant comparators to develop a series of adjustment factors which can be used to calibrate modelling results with practical experience.

The latest February 2012 release of GT PRO Version 22 was used to model the candidate plants and the models were then used in the cost estimation process.

The experience of PB over the past few years is that the supply and demand balance of power plant equipment has influenced EPC price fluctuations far more significantly than commodity prices. The appropriate default multipliers in the current release of PEACE are deemed (as was the case last year) to yield representative cost estimates for EPC prices.

*Final EPC cost estimates and candidate plant performance*

Applying the process outlined above gives final cost estimates as outlined in Table 3.3 using NI as the basis as there is a slight difference in EPC costs between jurisdictions due to differences in transmission voltages. The costs are shown together with the average lifetime net power output of the candidate plant options. These outputs are based on a water injection to fuel mass flow ratio of 1:1 where possible (and where not provided by the OEMs).

*Table 3.3: EPC cost estimate and power output for short-listed plants in NI.*

| Plant Type | Fuel Type | Average Lifetime Output (MW) | EPC Cost (€m)[4] |
|---|---|---|---|
| 1 x Alston GT13E2 | Distillate | 196.5 | 92.5 |
| | Gas | 198.0 | 92.4 |
| 1 x AE94.2 | Distillate | 166.4 | 82.3 |
| | Gas | 167.7 | 82.3 |
| 1 x SGT5-2000E | Distillate | 166.2 | 83.6 |
| | Gas | 167.8 | 84.4 |
| 3 x SwiftPac 60 | Distillate | 183.8 | 106.1 |
| | Gas | 185.1 | 106.4 |
| 2 x LMS 100 | Distillate | 198.6 | 125.3 |
| | Gas | 198.3 | 130.4 |

*Source: CEPA/PB*

As noted in Section 3.2.2, the IED limits do not apply where the total annual fired hours is less than 500, and so water injection is included for power augmentation, not for NOx control. In previous year studies, at the winter ambient temperature selected, there was a power limitation on the 13E2, AE94.2, and SGT5-2000E and the SwiftPac. Since the water injection, required for NOx control, would increase power beyond the limit, any increase in water injection merely increases heat rate without any increase in load, the GTs effectively operating at part load. Reducing the firing temperature to run at part load would reduce the NOx production, and hence required water/fuel ratio anyway. By removing the IED NOx limit, the water injection rate could be reduced to that just required to meet the power limit, resulting in lower heat rates for these machines. At higher ambient temperatures, the water injection rate can be increased when the GT attains full load.

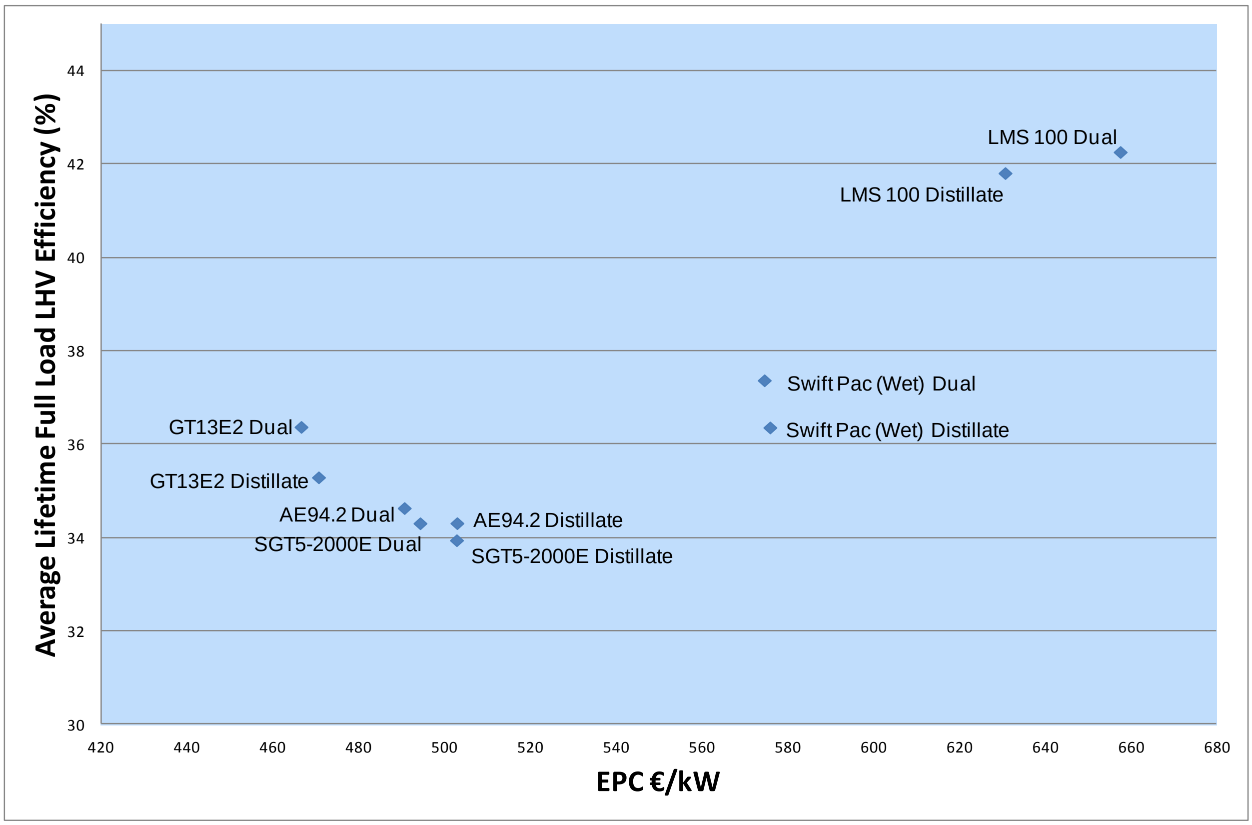
[4] Please note that approximately 5% contingency is included as an integrated part of the contractor price.

Changes to average lifetime output are based on the final release of GT Pro Version 22 and consultation with plant manufacturers.

In addition, average output degradation over the economic lifetime of the plants has been set at 2.5% and 2.0% for distillate and gas operation respectively. An average lifetime inlet pressure draught loss of 6 mbar has been applied.

To compare these options on a specific EPC cost basis, the costs are plotted against efficiency in the chart below (Figure 3.5). Average efficiency degradation over the economic lifetime of the plants has been set at 1.25% and 1.0% for distillate and gas operation respectively.

*Figure 3.5: Efficiency and EPC cost trade-off for short-listed plant*




## 3.5. Chosen technology option

Based on the assessment above, EPC costs per kW for the five candidate plants, firing both gas and distillate, are shown in Table 3.4.

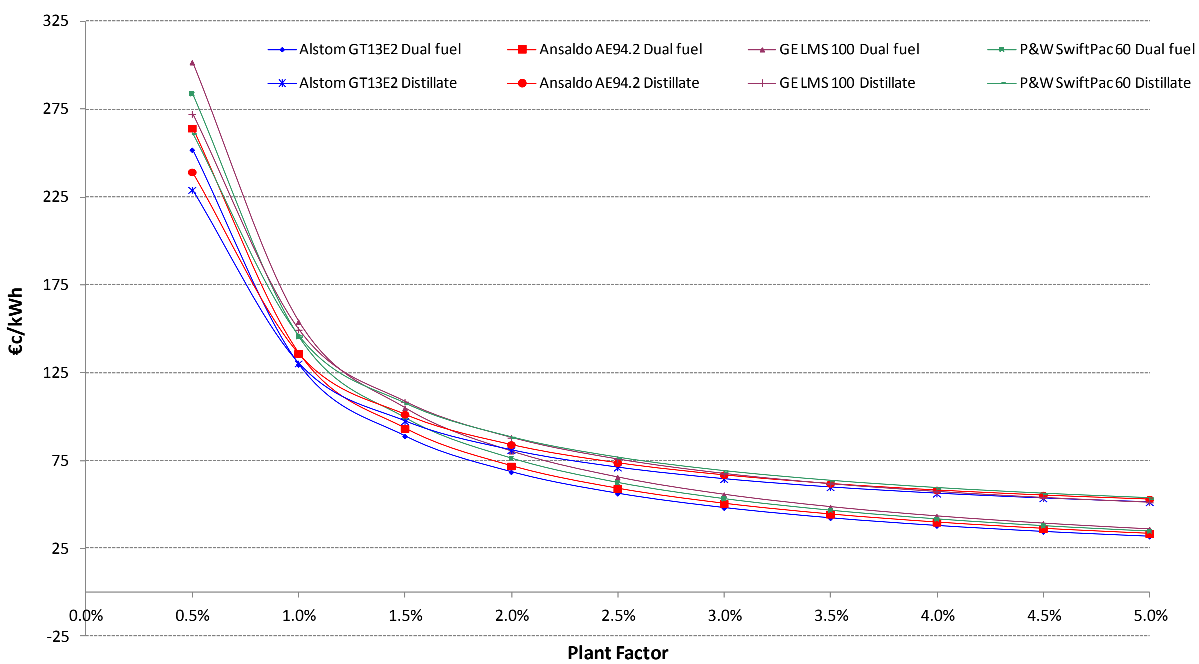
*Table 3.4: Specific EPC cost estimates for short-listed plants in NI.*

| Plant Type | Fuel Type | EPC Cost €/kW |
|---|---|---|
| 1 x Alston GT13E2 | Distillate | 470.8 |
| | Gas | 466.8 |
| 1 x AE94.2 | Distillate | 494.5 |
| | Gas | 490.8 |
| 1 x SGT5-2000E | Distillate | 503.0 |
| | Gas | 503.1 |
| 3 x SwiftPac 60 | Distillate | 577.3 |
| | Gas | 574.8 |
| 2 x LMS 100 | Distillate | 630.9 |
| | Gas | 657.7 |

*Source: PB*

While we note that based on current market conditions the plant is unlikely to run for a significant number of hours, for completeness and in keeping with the methodology used in previous years we have undertaken screening-curve analysis. The results of this analysis are shown in Figure 3.6.

*Figure 3.6: Screening curve analysis (generation cost vs. plant utilisation factor)*




*Source: CEPA/PB*

On the basis of the approach outlined above, in CEPA/PB's opinion, it is likely that the **BNE GT for 2013 is an Alstom GT13E2**. This plant has a capacity of 202MW (198.0MW with 2 per cent average degradation) in dual fuel configuration. Both the distillate and the dual fuel options are carried over for further analysis in the following sections for locations in both NI and RoI.

### 3.5.1. Technical assumptions for selected plant

The following has been built in to the performance and cost models for the 1 x ALS GT13E2 plant option:

- Ambient conditions at the grid's winter peak.
- Transmission voltage of 110kV for NI and 220kV for the RoI.
- Distillate storage for both distillate options of 3.5 days at maximum plant load and 3 days for dual fuel option to reflect secondary fuel obligation in Ireland.
- Water storage and treatment capability for 3.5 days of water injection at 1.18:1 water to fuel ratio (mass basis) at maximum plant load.
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.
- No black-start capability (it is assumed that had black-start capability been included, the additional costs would have been offset by the subtraction of the associated ancillary service revenue).
- Gas network pressure does not drop below 30 barG.
- Average lifetime draught losses of 6 and 12.5 mbar for inlet and outlet respectively.
- Average lifetime degradation for power output and heat rate of 2.5% and 1.25% respectively for distillate option and 2% and 1% for gas operation.

**Initial views**

- As the BNE plant will run for a very limited number of hours, cost is the key driver of plant choice.
- On this basis, the Alstom 13E2 appears (as in 2010, 2011 and 2012) to be the chosen GT.
- This plant will be assessed based on gas and distillate firing for sites in NI and the RoI.

# 4. Cost estimates

This section considers the investment and ongoing cost estimates associated with the BNE plants in NI and the RoI.

## 4.1. Types of cost

In this section we consider:

- Investment costs, which have been sub-divided as follows:
  - EPC contract and timeframe
  - Site procurement costs
  - Electrical interconnection costs
  - Gas and make-up water connection costs (where applicable)
  - Owner's contingency
  - Financing, Interest During Construction (IDC) and construction insurance
  - Up-front costs for fuel working capital
  - Other non-EPC costs
  - Market accession and participation fees
- Recurring operational costs, which have been sub-divided as follows:
  - Transmission and market operator charges
  - Operation and maintenance
  - Insurance
  - Rates
  - Working fuel capability

We discuss each element in turn below.

## 4.2. Location of the BNE plant

In common with the approach undertaken by the RAs in previous years, this section considers the costs associated with locating a BNE plant in either relevant jurisdiction. As we noted in our 2010, 2011 and 2012 BNE reports, there are a number of conventional generation plants expected to enter the market in the next ten years. Sourced from the All-Island Generation Capacity Statement (2012-2021) Table 4.1 lists thermal generators that have signed agreements and confirmed dates to connect to the island over the next ten years.

*Table 4.1: Confirmed contracted conventional generation capacity to the island up to 2021*

| Plant | Export capacity |
|---|---|
| Great Island CCGT | 459 |
| Nore Power | 98 |
| Caulstown | 55 |
| Dublin Waste to Energy | 62 |
| Cuilleen OCGT | 98 |
| Suit OCGT | 98 |

*Source: EirGrid/SONi*

As in previous years, for the RoI we consider that a BNE investor would be able to obtain agricultural land, probably close to a relatively unconstrained part of the transmission network. Our discussions with the RAs have once again identified the site of the former Belfast West power station as the appropriate location in NI. Although there are currently no plans to site a new power plant at this 18 acre site, the land has been cleared of the original power station and is part of the land-bank area reserved by the regulator for generation construction. For these reasons we have decided to consider specific costs for this site (noting the approach differs from that used in the RoI).

### 4.3. Investment costs

This section considers investment costs associated with the proposed site in NI and a likely site in the RoI.

#### 4.3.1. EPC contract price and timeframe

As outlined in the Section 3, the Alstom GT13E2 was modelled in GT PRO according to the assumptions given in Section 3.6.1 and no uplift was applied to the EPC cost estimate. The outcome of this process is shown in Table 4.2 below for the two jurisdictions.

*Table 4.2: EPC cost estimates for NI and RoI*

| Plant | Fuel type | EPC Costs (€ million) |
|---|---|---|
| NI | Distillate | 92.5 |
| | Dual | 92.4 |
| RoI | Distillate | 93.7 |
| | Dual | 93.7 |

The reason for the difference in the NI and RoI cost estimates is due to the difference in costs associated with the differing transmission voltages. The period over which the Alstom GT13E2 plant is expected to be built, from financial close to plant hand-over, has, in common with previous years, been estimated at 18 months. Note that whilst the shorter implementation time of aeroderivative GT-based plants, and the Pratt & Whitney SwiftPac in particular, typically results in cheaper owner costs, these do not yield cheaper total investment specific costs.

### 4.3.2. Site procurement costs in RoI

At the time of writing our 2011 BNE report, we noted that the evidence suggested that agricultural land values in RoI had suffered a major reduction for a third year in succession. Knight Frank Ireland reported that the national average price paid for farmland in 2009 dropped by 43% compared to 2008. The National Asset Management Agency (NAMA), a Government body established to manage the consequences of the financial crisis, noted that on average, property values across all sectors had fallen 47%.

However, recent research, also by Knight Frank Ireland, notes that for the first time in four years the national trend in agricultural land values is of increasing prices:

> "*There has been some very positive news for agriculture … prices have increased by as much as 14.7% nationally during 2011, which is highly promising for the farming economy.*"[5]

In the 2012 BNE report we retained the notional rate of €150k/acre for suitable greenfield land in the RoI used in our 2011 report. This was approximately a 50% decrease compared to the value used for our 2010 BNE report. While we noted it might be possible to secure a suitable site at a lower rate per acre, any affected landowner is likely to view a power station as industrial development (whether or not they had any likelihood of securing consent for such a use) and/or are likely to argue for injurious affection (diminution in value of land held with land taken).

We propose to retain the notional rate of €150k/acre for the 2013 BNE calculation as while market commentary suggests that agricultural land values have stabilised, we have seen no firm evidence to suggest that there has been a significant rise or fall in land values. We would welcome stakeholders' views on whether this assumption continues to be appropriate.

### 4.3.3. Site procurement costs in NI

Based on our discussions with the RAs we continue to assume Belfast West as the appropriate location for the BNE in NI.

The Belfast Harbour Estate is owned by two landowners and both these parties have a policy of not granting freeholds. Therefore notional capital values can only be derived from the ground rent information available within the estate assisted by capital evidence from other equivalent locations. As there is little evidence to support either a rise or fall in industrial land values in Belfast we do not propose to make an adjustment to the figure that was used in last year's decision. Hence we use a value of £250k/acre for site procurement costs in NI, which is a capitalised equivalent of the £15-40k/acre rental value.

[5] http://www.knightfrank.ie/resources/Farms_Market_Report2012.pdf

### 4.3.4. Summary of site procurement costs

Table 4.3 summarises our assessment of land costs for the BNE plant.

*Table 4.3: Assessment of land costs*

| Location | Fuel type | Required area (m2) | Estimated site cost (€) |
|---|---|---|---|
| NI | Distillate | 20,700 | €1,529,154 |
| | Dual | 20,500 | €1,514,379 |
| RoI | Distillate | 20,700 | €767,262 |
| | Dual | 20,500 | €759,849 |

Despite additional equipment being required for the dual fuel scenarios, the additional half a day's storage of liquid fuel for the distillate scenarios results in slightly larger land areas required (see Section 4.3.9 for a discussion of fuel storage requirements).

### 4.3.5. Electrical connection costs

A significant driver of the costs of a site is the electrical connection costs the site would face. The transmission voltages for RoI and NI are 220kV and 110kV respectively.

For NI, we have revised estimates for the Belfast West site provided to us by SONI in 2009. These are in the order of £9m based on 2 substations and a double circuit cable between Belfast West and Belfast Central. We have removed the cost of one substation as this cost is included in the EPC cost estimate and updated our estimate for 2012 for movements in metal prices.[6]

For the RoI we have adopted the same approach as the 2011 BNE decision paper. This assumes a 220kv design adjusted for a 4 km connection (i.e. 2km per leg of loop) with the costs of the connection based on CER's most recent published standard transmission connection charges.[7] The estimate of electrical connection costs in both jurisdictions is summarised in Table 4.4 below.

*Table 4.4: Electrical Connection Cost Estimates*

| Location | Electrical Connection Costs (€) |
|---|---|
| NI | €7,870,000 |
| RoI | €6,680,000 |

### 4.3.6. Gas and raw water connection

We have also estimated the costs associated with securing a water supply and a connection to the gas network (where applicable). For the water connection, the total cost of an installed 1km pipeline, 4 inches in diameter, has been assumed for RoI. This cost was estimated using GT MASTER/PEACE.

[6] We have assumed a 2 per cent increase in connection costs to reflect recent movements in metal prices.

[7] http://www.cer.ie/GetAttachment.aspx?id=1a1c0c08-83cc-4bf0-bb47-956011bc56e3

For the Belfast West site, the Consultation on Vacant Sites document[8] states that a water supply from the 9 inch pipeline running parallel with McCaughey Road feeds the vacant Belfast West site. The off-take to the site is currently disconnected at the security gatehouse, which constitutes the battery limit of the site. Given a water main runs adjacent to the site no costs have been allocated for the water connection beyond the battery limit (although the EPC cost includes the water supply pipeline from the battery limit).

We have used the same gas connection costs for NI and the RoI as the 2011 BNE decision paper. These are based on estimates received from Gaslink in developing the BNE price for 2010 revised in the determination of the pipeline and connection costs for a 1km pipeline for Belfast West and a 2km pipeline for the site in RoI.

*Table 4.5: Gas and raw water connection costs*

| Location | Cost of water connection (€) | Cost of gas connection (€) |
|---|---|---|
| NI | 0 | €1,810,000 |
| RoI | €480,000 | €3,620,000 |

### 4.3.7. Owners contingency

Owner's contingency covers such things as project delays due to force majeure events and the resulting lost revenue, additional civil works costs due to unexpected sub-terrain, and claims relating to interface problems. We have retained the assumptions from last year. Based on PB's project experience, 5.2% of the value of the EPC cost has been attributed to owner's contingency (in addition to the contingency within the EPC price).

*Table 4.6: Owners contingency*

| Location | Fuel Type | Owners contingency (€) |
|---|---|---|
| NI | Distillate | €4,810,000 |
| | Dual Fuel | €4,804,800 |
| RoI | Distillate | €4,872,400 |
| | Dual Fuel | €4,872,400 |

### 4.3.8. Financing, interest during construction and construction insurance

Our financing and construction insurance costs have been estimated as a proportion of EPC costs based on CEPA/PB's past experience. For interest during construction we have used the same approach as last year and calculated the interest on the loan amount drawn down in proportion to the gearing ratio prior to the plant earning revenues. Similar to last year we have not assumed any premium on the debt during the construction phase.

[8] http://www.uregni.gov.uk/news/view/update_on_the_consultation_on_vacant_sites_within_the_nie_land_bank

*Table 4.7: Financing, interest and insurance costs*

| Element | Total cost for distillate (€) | Total cost for duel fuel (€) |
|---|---|---|
| Financing NI | €1,850,000 | €1,848,000 |
| Financing RoI | €1,874,000 | €1,874,000 |
| IDC NI | €2,204,216 | €2,233,493 |
| IDC RoI | €3,305,708 | €3,406,774 |
| Construction Insurance NI | €832,500 | €831,600 |
| Construction Insurance RoI | €843,300 | €843,300 |

### 4.3.9. Fuel working capital assumption

It is necessary to include the costs of fuel which needs to be held to comply with various regulatory policies as a BNE capital cost. In the RoI this cost is driven by the secondary fuel obligation. For gas plant this states:

> *Generating units that expect to operate less than 2,630 hours per year are categorised as lower merit generating units for the purpose of this proposed decision. These units are required to hold stocks equivalent to three days continuous running based on the unit's rated capacity on its primary fuel.*[9]

We note that secondary fuel requirements in NI are currently under review by DETI as part of the redrafting of the NI fuel security code.[10] In the absence of further information it is assumed that the above obligation would be applicable in either jurisdiction.

At the outset of the project an investor will need to pay for this fuel. We have therefore assumed an initial fuel storage fill cost of €5.04m for a distillate plant and €4.23m for a dual fuel plant, based on a requirement to run for 72 hours full load, as well as an additional 0.5 days of commercial running for distillate plants and an oil price of US$123.24/barrel[11]. It is assumed that this fuel is sold back at the end of the plant life. Consistent with the 2012 BNE decision, excise duty has also been added to fuel costs for NI plant.

Our cost estimate for fuel working capital is provided in Table 4.8 below.

*Table 4.8: Initial fuel working capital*

| Element | Total cost for distillate (€) | Total cost for dual fuel (€) |
|---|---|---|
| Fuel working capital | €5,044,812 | €4,227,704 |

[9] Secondary Fuel Obligations on Licensed Generation Capacity in the Republic of Ireland

[10] http://www.detini.gov.uk/deti-energy-index/deti-energy-consultations/revision_of_northern_ireland_fuel_security_code___draft_northern_ireland_fuel_security_code.htm

[11] Oil price used was ICE Brent Crude as traded on 31st March 2012 (sourced from CEPA Bloomberg subscription).

#### 4.3.10. Other non-EPC costs

In keeping with the presentation of "Other non-EPC costs" from last year, the reasoning behind this grouping of costs is as follows. While the costs specified above are relatively easily determinable, many of the costs under "Other non-EPC costs" are difficult to benchmark against other projects due to varying definitions and groupings of costs. The types of costs covered by "Other non-EPC costs" include Environmental Impact Assessment (EIA), legal, owner's general and administration, owner's engineer, start-up utilities, commissioning, O&M mobilisation and spare parts.

This same grouping of costs has been benchmarked against several relevant projects for which PB performed the role of lender's engineer, obtaining access to total project costs. From this benchmarking exercise, the percentage of EPC cost allocated to Other non-EPC costs is 9.0%.

*Table 4.9: Other non-EPC costs*

| Location | Fuel type | Other non-EPC costs |
|---|---|---|
| NI | Distillate | €8,325,000 |
| NI | Dual fuel | €8,316,000 |
| RoI | Distillate | €8,433,000 |
| RoI | Dual fuel | €8,433,000 |

#### 4.3.11. Market accession and participation fees

The BNE plant will also need to pay market accession and participation fees before beginning operating. Participation fees have been reduced slightly compared to the previous year costs as shown in Table 4.10 below.[12]

*Table 4.10: Market accession and participation fees*

| Type of charge | Basis for calculation | Charge amount | Total cost |
|---|---|---|---|
| Accession fee | Fixed charge to cover costs of assessing application | € 1,115 | € 1,115 |
| Participation fee | The fee payable with an application to register and become a participant in respect of any Unit. | € 2,788 | € 2,788 |

### 4.4. Recurring cost estimates

In addition to identifying investment costs, it is necessary to consider the recurring costs that the BNE plant will face. These issues are discussed in this section.

[12] http://www.sem-o.com/Publications/General/2011-12%20SEMO%20Tariffs%20and%20Imperfections%20Costs.pdf

### 4.4.1. Electricity transmission and market operator charges

As part of its role in the administration of the market, there are charges which the SEMO must levy in order to recover its own allowed costs and allowed market related costs.

These charges consist of:

- the Imperfections Charge,
- the Market Operator charges, and
- the generator under test tariff.

For the purposes of this analysis, the Transmission Use of System (TUoS) charges and Market Operator charges are relevant.

*Market operator charges*

Table 4.11 provides our initial estimate of the Market Operator tariffs which apply to the BNE peaking plant. SEMO Market Operator charges have increased compared to the previous year costs.

*Table 4.11: Market operator charges*

| Type of charge | Charge amount | Total Cost |
|---|---|---|
| Fixed market operator tariffs | € 109.00 | Distillate - €21,414<br>Dual - €21,578 |

*Transmission Use of System charges*

The development of harmonised all-island transmission Generator charges was an objective stated in the original 2005 SEM high level design. The SEM Committee recently published a decision paper[13] on the calculation method for all-island G-TNUoS tariffs, the TSO's G-TNUoS methodology statement and all-island G-TNUoS tariffs for the tariff year 1st October 2011 to 30th September 2012.

For the BNE 2013 calculation we have used:

- the average locational G-TNUoS tariff for NI sites; and
- the average locational TNUoS tariff for RoI sites

for the notional NI and RoI site respectively. This includes wind and non-wind generation. Our estimates of electricity transmission capacity charges are summarised in Table 4.12 below.

[13] http://www.allislandproject.org/GetAttachment.aspx?id=91fcf973-e74f-438d-8f08-d951dd0df291

*Table 4.12: TUoS charges*

| Location | Fuel Type | TUoS charge (€) |
|---|---|---|
| NI | Distillate | €1,146,691 |
| | Dual Fuel | €1,155,431 |
| RoI | Distillate | €977,129 |
| | Dual Fuel | €984,577 |

### 4.4.2. Gas transmission charges

For the dual fuelled plant we also need to consider gas transmission charges. There are a series of short and long-term products available in the RoI and interruptible products available in NI. However we have assumed a rational investor would purchase an annual product.

Gaslink "Code of Operations" paragraph 7.3.7, requires a peaking plant to book capacity for a minimum of 16/24 of its "maximum hourly quantity". Accordingly our gas transmission charge calculation assumes that on a peak day the BNE plant would run for 16 hours.

On that basis our estimates for gas capacity charges are shown below.[14] RoI transmission charges are available from Gaslink for 1st October 2010 to 30th September 2011.[15] The postalised capacity charge for the NI transmission system is published by Bord Gais Networks, including a forecast for gas years 2011/12 to 2014/15.[16] We have used the forecast NI postalised capacity charge for the 2012/13 gas year.

*Table 4.13: Gas transmission charges*

| Jurisdiction | Cost per kWh [1] | Plant size (MW) | Efficiency (%) | Assumed hours run | Transmission charge |
|---|---|---|---|---|---|
| NI capacity | 0.35164 | 197.96 | 36.4% | 16 hours [2] | €4,079,686 |
| RoI (capacity) | | | | | |
| Onshore | 0.440657 | 197.96 | 36.4% | 16 hours [2] | €6,080,654 |
| Interconnection | 0.189884 | | | | |

*Note 1: Peak day capacity*

*Note 2: Per peak day*

[14] Similar to our BNE report for last year we have used the following calculation for the Republic of Ireland:
(Plant Output/ Load Factor/ Calorific Value Conversion Factor) x Running Hours x (Onshore Tariff + Interconnector Tariff) = Total Gas Transmission Charges
And for Northern Ireland:
(Plant Output/ Load Factor/ Calorific Value Conversion Factor) x Running Hours x (Postalised Tariff) = Total Gas Transmission Charges

[15] http://www.gaslink.ie/files/Copy%20of%20library/20110908034456_BGN%20Transmission%20Tariff%20for%20Ga.pdf

[16] http://www.bordgais.ie/networks/media/PostalisationTransmissionTarifffforGasYear2010-20111.pdf

### 4.4.3. Operation and maintenance costs

Similar to previous years, the plant is assumed to be manned by multi-skilled staff capable of operating the plant and performing minor maintenance activities not covered by the Long Term Service Agreement (LTSA). Five shifts of two multi-skilled operators have been assumed, together with an allocation for general and administration costs, amounting to an estimated €470,000 per year. Consistent with the approach used in previous years, any differences between locations (such as, for example, labour rates) have not been considered.

The fixed annualised LTSA maintenance costs of the plant are based on the minimum maintenance regime for the GT13E2 recommended by Alstom for units running less than 3000EOH per year. Recent LTSA costs for a GT13E2 plant have been reviewed and there does not appear to be a significant move in the prices. For the distillate option, the fixed annualised LTSA maintenance costs amount to an estimated €1,432,000 and for the dual fuel option, €1,458,000. Since the fixed LTSA payments have been anticipated to cover the minimum recommended maintenance regime for low-utilisation plants, it has been assumed that the cost of full parts replacement at 48,000EOH is accounted for through a variable maintenance cost that is bid into the market.

*Table 4.14: Fixed operation and maintenance costs*

| Fuel type | O&M Costs (€) |
|---|---|
| Distillate | €1,902,000 |
| Dual fuel | €1,928,000 |

### 4.4.4. Insurance

Our insurance estimate is based on a percentage of EPC costs and is based on past experience. As for last year's calculation, we have assumed insurance costs are 1.6% of EPC costs.

*Table 4.15: Insurance costs*

| Fuel Type | NI (€) | RoI (€) |
|---|---|---|
| Distillate | €1,480,000 | €1,499,200 |
| Dual Fuel | €1,478,400 | €1,499,200 |

### 4.4.5. Business rates

Business rates are annual taxes paid on the value of a property. They are paid on a local (and in NI also regional basis). We have used the same approach to determining business rates as used in previous years. For NI we have used the valuation formula from the "Valuation (Electricity) Order (Northern Ireland) 2003", which sets out how electricity generating stations are valued for tax purposes. We have used the local and regional tax rates applicable in the Belfast area.[17] For the RoI we have retained the valuation formulae used in previous years, whereby the plant is valued at

[17] http://www.dfpni.gov.uk/lps/index/property_rating/rate-poundages-2012.htm

€115/MW and the multiplier rate on valuation is 68. From our research we have not found clear evidence to consider it appropriate to revise these.

*Table 4.16: Annual business rates*

| Fuel Type | NI (€) | RoI (€) |
|---|---|---|
| Distillate | €695,082 | €1,538,343 |
| Dual Fuel | €700,380 | €1,550,069 |

### 4.5. Summary

The tables below summarise our findings for investment and recurring costs for both fuel options and our chosen locations in both NI and the RoI.

*Table 4.17: Investment cost estimates (€)*

| Fuel Type | NI Distillate | NI Dual Fuelled | RoI Distillate | RoI Dual Fuelled |
|---|---|---|---|---|
| EPC costs | €92,500,000 | €92,400,000 | €93,700,000 | €93,700,000 |
| Site procurement cost | €1,529,154 | €1,514,379 | €767,262 | €759,849 |
| Electrical Connection costs | €7,870,000 | €7,870,000 | €6,680,000 | €6,680,000 |
| Water connection costs | €0 | €0 | €480,000 | €480,000 |
| Gas connection costs | €0 | €1,810,000 | €0 | €3,620,000 |
| Owners contingency | €4,810,000 | €4,804,800 | €4,872,400 | €4,872,400 |
| Financing costs | €1,850,000 | €1,848,000 | €1,874,000 | €1,874,000 |
| Interest during construction | €2,204,216 | €2,233,493 | €3,305,708 | €3,406,774 |
| Construction insurance | €832,500 | €831,600 | €843,300 | €843,300 |
| Initial fuel working capital | €5,044,812 | €4,227,704 | €4,434,796 | €3,716,492 |
| Other non EPC costs | €8,325,000 | €8,316,000 | €8,433,000 | €8,433,000 |
| Accession fees | €1,115 | €1,115 | €1,115 | €1,115 |
| Participation fees | €2,788 | €2,788 | €2,788 | €2,788 |
| **Total** | **€124,969,584** | **€125,859,879** | **€125,394,369** | **€128,389,718** |

*Table 4.18: Recurring cost estimates*

| Fuel Type | NI Distillate | NI Dual Fuelled | RoI Distillate | RoI Dual Fuelled |
|---|---|---|---|---|
| Market operator charges | €21,414 | €21,578 | €21,414 | €21,578 |
| Electricity transmission charges | €1,146,691 | €1,155,431 | €977,129 | €984,577 |
| Gas transmission charges | €0 | €4,055,606 | €0 | €6,080,654 |
| Operation & Maintenance | €1,902,000 | €1,928,000 | €1,903,000 | €1,929,000 |
| Insurance | €1,480,000 | €1,478,400 | €1,499,200 | €1,499,200 |
| Business rates | €695,082 | €700,380 | €1,538,343 | €1,550,069 |
| Fuel working capital (ongoing)[18] | €325,523 | €272,798 | €376,577 | €315,583 |
| **Total** | **€5,570,710** | **€9,612,193** | **€6,315,664** | **€12,380,660** |

## 4.6. Summary

**Initial views**

- Our initial view is that a distillate and dual fuelled BNE plant sited in NI is likely to be cheaper than a BNE plant (distillate or dual fuelled) sited in the RoI.
- The lower BNE costs in NI are driven mainly by its lower financial costs (e.g. interest during construction) as discussed in Section 5.
- However, to be consistent with regulatory precedent we propose to calculate the full BNE price for the BNE site in NI and RoI.
- As in previous years, on the basis of our initial cost analysis the BNE plant is highly likely to be distillate fired.

[18] Similar to the approach taken in previous years we have included an opportunity cost for holding fuel at the plant. This is calculated as the initial cost of the fuel multiplied by the WACC.

# 5. ECONOMIC AND FINANCIAL PARAMETERS

This section outlines our consideration of the economic and financial parameters applying to the BNE plant. It follows the format and approach CEPA used in respect of the BNE calculation for the 2010, 2011 and 2012 trading years. Analysis is summarised here and more detailed supporting information is provided in Annex 2.

## 5.1. Approach

CEPA's approach to deriving the appropriate Weighted Average Cost of Capital (WACC) for the investment in the BNE plant is broadly unchanged from the 2010, 2011 and 2012 exercise. Within that approach, all parameters have been re-considered in light of data which has become available since the last decision. Although a broad range of academic and market evidence exists on the cost of capital for utilities, both in RoI and the UK, the RA's continue to face a difficult task in determining a forward-looking estimate of the cost of capital for the BNE given the limited precedent of regulators setting a WACC for a generator subject to competitive and market constraints. In the RoI, this task is made even harder by the Euro-zone sovereign debt crisis.

In order to address these factors, we continue to make use of traditional finance theory and cross check this against market evidence.

We note both CER and NIAUR are expected to set a precedent for the WACC in both the RoI and NI as part of the ongoing price control reviews of Bord Gáis Networks (BGN) and Northern Ireland Electricity (NIE) transmission and distribution. As consultation papers for each control have yet to be published, we have not reviewed the RAs analysis but will consider this evidence as part of the next phase of the BNE calculation process.

Our review of the evidence from the BGN and NIE price reviews may require an update to the BNE WACC parameter ranges below.

### 5.1.1. Building blocks of a BNE cost of capital

In line with the majority of regulatory agencies in the RoI and the UK, the approach we adopt in this report is the building-block approach to the WACC. This involves an estimation of the appropriate gearing (measured as net debt: net debt plus equity); cost of debt; cost of equity; and an allowance for the taxation costs of a BNE peaking plant.

An allowance needs to be made for corporation tax payments for the BNE project. This can be done either through a pre-tax WACC or through a post-tax WACC with a separate tax allowance. For the current purposes, a pre-tax allowance is considered more practical and is in line with previous RA decisions.

We also use a real WACC rather than a nominal WACC as the prices used in the BNE computation are real prices.

### 5.1.2. BNE peaking plant investment

The RA's are seeking to estimate the cost of capital associated with a BNE peaking plant entering the SEM in the calendar year 2013. This requires assumptions on the nature of the BNE investment, in terms of the profile of the hypothetical BNE investor, including its credit rating, and the financing structure adopted by that investor. Our key assumptions for assessing the cost of capital for the BNE peaking plant are unchanged from our assumptions last year, and are summarised in the Text Box 5.1 below.

**Text Box 5.1: BNE 2012: peaking plan investment assumptions**

- **Type of investor** - we assume that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level.
- **Plant life** – in line with the 2010 and 2011 BNE calculation the economic life of the project has been taken as 20 years.
- **Financing structure** – we assume that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Thus we assume an average tenor of 10 years on the new debt.
- **Financing structure -** we also assume that the investor would seek to maximise the debt/equity ratio. Consistent with the 2011 calculation, in the current financial markets this would mean a gearing ratio of 60%.
- **Credit quality** – we assume that a BNE investor has an investment grade credit rating in the range BBB to A. In our analysis of market data, we have employed data for BBB grade debt, which is a more conservative assumption.
- **Investment type** - our assumption is also that the BNE is a green-field investment with no existing assets and associated financing costs. This means that the cost of capital for the BNE is purely a forward-looking estimate for an efficiently operated and financed peaking plant.

## 5.2. Estimate of BNE cost of capital

### 5.2.1. Gearing

As we have noted in our previous BNE reports, identifying an appropriate gearing assumption for the BNE is inevitably a judgment as the plant is a notional investment in the SEM. We have seen no compelling evidence to change our gearing assumption of 60% for the BNE. We welcome evidence from stakeholders' on whether this assumption continues to be appropriate.

### 5.2.2. Cost of debt

In line with our previous BNE reports, in assessing the risk-free rate for the UK we have looked at market evidence for nominal and index-linked gilts from the UK. For the UK debt premium we have looked at spreads over benchmark gilts, as well as costs for recent issues by investment grade utilities in the UK. On the basis of the evidence presented in Annex 2, our estimate of the appropriate range for the BNE cost of debt 3.25% - 4.75% in the UK. This includes an uplift of 50bps added to the top end of the range for the debt premium to account for a premium on NI utility debt compared to spreads implied by generic UK corporate bond indices.

Assessing the cost of debt for the BNE in the RoI is made more difficult with the Euro-zone sovereign debt crisis. The evidence presented in Annex 2 shows that the breakout of the global financial crisis and the sovereign debt crisis in the Euro-zone has led to a re-evaluation of risk by investors in the different member states.

The specific risk profile of RoI assets can be accounted for in calculating the WACC in one of two ways. The first would be to rely solely on information from Irish markets (including Irish government bonds for the risk-free rate and spreads on Irish corporate bonds for the debt premium). However, while this would represent the preferred solution, as we noted in our previous BNE reports, we consider this approach to be problematic, because the Irish market is relatively small and illiquid.

The alternative approach is to rely on a wider range of information, from across the Euro-zone, but to make an explicit adjustment to the risk faced by investors in the RoI by including a Country Risk Premium (CRP) in the WACC. To incorporate a RoI CRP, an adjustment could be made to the WACC in one of two ways:

- either to the risk-free rate; or
- to the risk premia for Irish assets (the debt premium and equity risk premium).

As explained in Annex 2, we propose that the appropriate cost of debt to allow a BNE peaking plant investment in the RoI for 2013 lies within the range 3.5% - 8.5%.

The top end of the range accounts for the uncertain and challenging financing conditions in the RoI but also that the BNE credit risk and borrowing costs, while likely to be correlated to the cost of debt faced by the state, is primarily related to participation in the SEM.

The bottom of the range reflects evidence of recent Euro-zone corporate borrowing costs including ‘periphery’ Euro-zone corporate utility debt currently trading with a higher debt premia than the cost of debt for generic Euro-zone corporate bond indices.

### 5.2.3. Cost of equity

We have again deployed the Capital Asset Pricing Model (CAPM) as the primary tool for estimating the cost of equity, with a cross-check to recent regulatory precedent.

Our judgement is that the appropriate range for the post-tax cost of equity for the BNE peaking plant is 7.90% - 13.50% in the RoI and 6.90% - 8.50% in the UK.

#### 5.2.4. Taxation

We have again calculated the WACC for the BNE on a real pre-tax basis using an assumed statutory corporation tax rate for the jurisdiction in which the BNE is located.

#### 5.2.5. Single electricity market WACC

The decision paper for Medium Term Review notes the following:

"*Regarding the economic parameters, the Regulatory Authorities will be asking the BNE consultants to provide the SEM Committee with additional information regarding the WACC. The SEM Committee will review this information and determine the methodology to be implied in the 2013 BNE consultation paper.*"[19]

Discussion of a single electricity market WACC is provided in Annex 3.

#### 5.2.6. WACC

Our judgement of the appropriate range for the real pre-tax WACC for the BNE peaking plant is thus 5.71% - 11.3% in the RoI and 5.58% - 7.32% in the UK. We note our proposed ranges for the UK BNE WACC parameters are not inconsistent with the parameters that have been proposed by the Utility Regulator for NIE T&D's price control WACC (see Annex 2).

**Initial views**

- On the basis of market evidence and new regulatory precedent, we believe that a reasonable estimate for the gearing of the BNE continues to be 60%.
- We continue to assume that the plant life for the BNE will be 20 years and that the BNE investor would target an average debt life of 10 years.
- We also continue to conservatively assume that whilst the investor will be 'investment grade', the debt raised will be based on BBB grade costs.
- Our estimate of the appropriate range for the BNE cost of debt is 3.5% - 8.5% in the RoI and 3.25% - 4.75% in the UK.
- Our judgement of the appropriate range for the post-tax cost of equity in the UK and RoI is 6.9% - 8.5% and 7.9% - 13.5% respectively.
- We have calculated the WACC for the BNE on a real pre-tax basis using an assumed statutory corporation tax rate for the jurisdiction in which the BNE is located.
- This points to a range for the assumed real pre-tax WACC of 5.7% - 11.3% in the RoI and a range of 5.6% - 7.3% in the UK.

[19] SEM-12-016

# 6. INFRA-MARGINAL RENT AND ANCILLARY SERVICE REVENUES

We now proceed to calculate the inframarginal rent for the selected peaker. Our approach replicates the process used in the previous three years: that is to subtract revenues accruing to the BNE peaker as a result of activity in the energy market and Ancillary Service (AS) revenues. This section provides the results of modelling to determine infra-marginal rents and AS revenues.

## 6.1. Infra-marginal rent

The RAs have adopted the formulae set out in the MTR decision paper to determine the Infra-Marginal rent which will be earned by the BNE plant. The RAs have identified that €5.54/kW infra-marginal rent would be earned by the plant.

## 6.2. Ancillary services revenue

Estimates of AS revenues are based on information provided by the TSOs who reviewed the unit for the 2012 BNE calculation decision paper. We have updated the AS income and penalties to account for the change in the average lifetime output of the 2013 BNE plant using the current harmonised AS rates and other system charges. The parameters adopted in BNE AS revenue calculation are as follows:

*Table 6.1: Ancillary Service values for use in the BNE calculation for 2013*

| Parameter | Value | Unit | Source |
|---|---|---|---|
| POR | 21.2 | MW | SONI Minimum Function Spec for OCGTs |
| SOR | 35.4 | MW | SONI Minimum Function Spec for OCGTs |
| TOR1 | 35.4 | MW | SONI Minimum Function Spec for OCGTs |
| TOR2 | 35.4 | MW | SONI Minimum Function Spec for OCGTs |
| RR | 196.5 | MW | SONI Minimum Function Spec for OCGTs |
| Min MW for POR | 19.7 | MW | SONI Minimum Function Spec for OCGTs |
| Min MW for SOR | 19.7 | MW | SONI Minimum Function Spec for OCGTs |
| Min MW for TOR1 | 19.7 | MW | SONI Minimum Function Spec for OCGTs |
| Min MW for TOR2 | 19.7 | MW | SONI Minimum Function Spec for OCGTs |
| Min MW for RR | 0.0 | MW | SONI Minimum Function Spec for OCGTs |
| Reactive Power Leading | 64.6 | MVAr | SONI Minimum Function Spec for OCGTs |
| Reactive Power Lagging | 147.4 | MVAr | SONI Minimum Function Spec for OCGTs |

Using these values and the RA assumption of 60% load factor when running gives the following output for AS revenues:

*Table 6.2: Ancillary Services for 2013 BNE*

| Parameter | Not Running [€/TP] | Running [€/TP] |
|---|---|---|
| POR | | 23.53 |
| SOR | | 37.7 |
| TOR1 | | 31.15 |
| TOR2 | | 15.58 |
| RR | 50.11 | 7.86 |
| Reactive Power Leading | | 8.4 |
| Reactive Power Lagging | | 19.16 |
| **Total** | **50.11** | **143.38** |

The potential AS income using the RA assumption of 95% availability and 2% run hours is therefore = (50.11 * 0.93 * 48 * 365) + (143.38 * 0.02 * 48 * 365) = €866,713

In the 2012 BNE decision paper, the RAs also clarified the applied penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events. A 196.5MW direct trip and a 196.5MW SND at zero notice time gives:

- Trip Charge: = €10,499
- SND (current 10/11 rates): = €7,860

This gives a value of AS revenues that the BNE peaking plant for 2013 would achieve of €848,354 as illustrated in Table 6.3 below.

*Table 6.3: Annual ancillary services revenues*

| Fuel choice | Ancillary Services |
|---|---|
| AS payments | €866,713 |
| Trip Charge | €10,499 |
| SND | €7,860 |
| **Total (Distillate (Northern Ireland))** | **€848,354** |

## 7. INITIAL VIEW OF THE BNE PRICE

Based on the discussions in the previous sections of this document, we now provide our initial estimate of the fixed costs of a distillate fired BNE peaking plant located at Belfast West or a notional site in the RoI.

### 7.1. Additional modelling assumptions

In order to increase transparency, the other modelling assumptions we have used and brief justifications for those assumptions are given below.

*Table 7.1: Justification for key modelling assumptions*

| Assumption | Justification |
|---|---|
| Euro to Sterling exchange rate is 1.1958 Euros to the pound. | Spot rate at time of developing document. Spot rate viewed as best indicator of future rate. |
| Midpoints of ranges for cost of capital have been used. | CEPA/PB have recommended ranges, the midpoint is used for ease but does not necessarily represent our view on the point estimate of the cost of capital. |
| Residual value of land and fuel included by present valuing of end term values | These items will have a real value that can be realised in the market |
| No residual value for plant | Plant life is assumed to be 20 years |
| Interest During Construction (IDC) | Based on steady drawdown of loan in proportion to gearing |
| Initial Working Capital | Initial fuel charge plus two month's payables |
| Owner's contingency | Included |
| Capacity MW | On a sent out basis allowing for degradation |

### 7.2. Results

Table 7.2 overleaf brings together the issues discussed in the previous sections to provide our initial assessment of the costs of locating a BNE plant in either the RoI or Belfast West in NI. On the basis of the analysis set out, the costs would be:

- At Belfast West **€86.19/kW/yr**.
- In the RoI **€100.34/kW/yr**.

This is before deductions for infra marginal rent and ancillary service revenues.

*Table 7.2: Summary assessment of the costs of a distillate fired BNE plant in the RoI or NI*

| Line Item | Unit | NI | RoI |
|---|---|---|---|
| Total investment costs | € million | 119.92 | 120.96 |
| Land and Fuel Residual Value | € million | -1.88 | -1.02 |
| Initial Working Capital | € million | 7.64 | 6.93 |
| Total Annual Costs | € million | 16.93 | 19.71 |
| Plant Size | MW | 196.5 | 196.5 |
| Pre Tax WACC | % | 6.45% | 8.49% |
| Plant Life | Years | 20 | 20 |
| **Estimated BNE cost (before reductions** | €/kW | **86.19** | **100.34** |
| | | | |
| Inframarginal Rent | €/kW | 5.54 | |
| Ancillary Service revenues | € 000/annum | 848.4 | |
| **Estimated BNE cost** | €/kW | **76.34** | |

**Initial views**

- We therefore consider, albeit on the basis of initial analysis, that the plant should be distillate fired and located at the Belfast West site in NI.
- The estimated cost of €76.34/kW remains unchanged from the €76.34 allowed for 2012.

# ANNEX 1: CEPA/PB LONG-LIST OF PLANT

**Main Considerations of 50 Hz Technology Options between 35MW and 200MW**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 (OUTPUT) | Ansaldo AE64.3A | Ansaldo AE94.2 | GE 6591C | GE 6111FA | GE 9171E | GE 9231EC | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 PA | P&W FT4000 Swift Pac | P&W FT8 Swift Pac 60 (wet) | RR RB211-H63 | RR Trent 60 Dry | RR Trent 60 WLE | Siemens SGT-750 | Siemens SGT-800 | Siemens SGT-1000F | Siemens SGT5-2000E | Siemens SGT5-3000E | Aggregated Generating Units |
| Nom. Power | 115.4 MW | 184.5 MW | 75.0 MW | 170.0 MW | 43.0 MW | 78.3 MW | 127.6 MW | 173.0 MW | 50.8 MW | 54.2 MW | 103.0 MW | 120.0 MW | 62.0 MW | 44.0 MW | 52.7 MW | 64.0 MW | 37.0 MW | 47.0 MW | 67.4 MW | 169.0 MW | 190.8 MW | 50.0 MW |
| Website | | | | | | | | | | | | | | | | | | | | | | |
| GT Pro | | | | | | | | | | | | | | | | | | | | | | |

**PASS/FAIL Criterion: Is the technology option still commercially available, i.e. is the supplier still marketing the equipment?**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 | Ansaldo V64.3A | Ansaldo AE94.2 | GE 6591C | GE 6111FA | GE 9171E | GE 9231EC | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 | P&W FT4000 Swift Pac | P&W FT8 Swift Pac 60 (wet) | RR RB211-H63 | RR Trent 60 Dry | RR Trent 60 WLE | Siemens SGT-750 | Siemens SGT-800 | Siemens SGT-1000F | Siemens SGT5-2000E | Siemens SGT5-3000E | Aggregated Generating Units |

**PASS/FAIL Criterion: Does the technology option have a proven track record, i.e. 3 x heavy duty GT > 8000hrs each or 3 x aero > 500 starts each?**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 | Ansaldo V64.3A | Ansaldo AE94.2 | | GE 6111FA | GE 9171E | | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 | P&W FT4000 Swift Pac | P&W FT8 Swift Pac 60 (wet) | RR RB211-H63 | RR Trent 60 Dry | RR Trent 60 WLE | Siemens SGT-750 | Siemens SGT-800 | | Siemens SGT5-2000E | | Aggregated Generating Units |

**PASS/FAIL Criterion: Can the technology option ramp up to full load in 20 minutes?**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 | Ansaldo V64.3A | Ansaldo AE94.2 | | GE 6111FA* | GE 9171E | | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 | P&W FT4000 Swift Pac | P&W FT8 Swift Pac 60 (wet) | RR RB211-H63 | RR Trent 60 Dry | RR Trent 60 WLE | Siemens SGT-750 | Siemens SGT-800 | | Siemens SGT5-2000E | | Aggregated Generating Units |

* The GE 6111FA requires 23 minutes to reach full load.

**PASS/FAIL Criterion: Can the technology fire liquid fuel?**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 | Ansaldo V64.3A | Ansaldo AE94.2 | | | GE 9171E | | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 | P&W FT4000 Swift Pac | P&W FT8 Swift Pac 60 (wet) | RR RB211-H63 | RR Trent 60 Dry | RR Trent 60 WLE | Siemens SGT-750 | Siemens SGT-800 | | Siemens SGT5-2000E | | Aggregated Generating Units |

**Indicators**

| No. | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 | 12 | 14 | 15 | 17a | 17 | 18a | 18 | 19 | 20a | 20 | 22 | 23 | 24 | 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option | Alstom GT11N2 | Alstom GT13E2 | Ansaldo# V64.3A | Ansaldo AE94.2 | | | GE 9171E | | GE LM6000PC Sprint | GE LM6000PG Sprint | GE LMS100 | | P&W FT8 Swift Pac 60 (wet) | | | RR Trent 60 WLE | | Siemens SGT-800 | | Siemens SGT5-2000E | | Aggregated Generating Units |
| ISO efficiency | 33.9 | 37.4 | 36.0 | 35.0 | | | 33.9 | | 40.2 | 40.0 | 43.2 | | 38.4 | | | 41.5 | | 37.5 | | 35 | | 35 |
| GTW equipment USD/kW | 256 | 232 | 284 | 234 | | | 248 | | 325 | 328 | 300 | | 300 | | | 310 | | 328 | | 228 | | 200 |
| Short List* | | Alstom GT13E2 | | Ansaldo AE94.2 | | | GE 9171E | | | | GE LMS100 | | P&W Swift Pac | | | | | | | SGT5-2000E | | |

## ANNEX 2: COST OF CAPITAL FOR A BNE PLANT

### A1 Overview

This annex sets out our analysis of the weighted average cost of capital (WACC) for a BNE peaking plant seeking to enter the SEM in the calendar year 2013. It begins with a review of the previous year's BNE cost of capital decision, and an overview of our proposed methodology for estimating the cost of capital in the forthcoming CPM determination. The subsequent sections set out our position on the individual parameters in the calculation and our approach to choosing an estimated range that emerges from the analysis.

### A2 Summary of previous year determination

In the cost of capital determination for 2010, 2011 and 2012, analysis by CEPA set out proposed parameters for input to a WACC calculation using the standard approach of basing the cost of debt on observable market data taken from the debt markets and a capital asset pricing model (CAPM) derived cost of equity (CoE). Table A1 summarises the individual parameters that the RAs used in the decision paper for 2012.[20] The key points to note from the decision are as follows:

- The RAs used a real cost of debt of 7.5% for the RoI and 3.75% for the UK. This was derived on the basis of an international utility with a credit rating of BBB operating the BNE and was based on government and corporate bond market data from Europe and the UK.
- The real post-tax cost of equity for a BNE plant was estimate as 11.45% for the RoI and 7.70% for the UK. This was based on an equity risk premium (ERP) of 4.75% and an equity beta for the BNE of 1.25.
- The statutory tax rate was used to turn the WACC into a pre-tax allowance and was based on the jurisdiction in which the BNE was located (i.e. a tax rate of 12.5% was used for the RoI and a rate of 26.0% was used for the UK).

These individual parameters resulted in a real BNE pre-tax WACC of 9.74% for the RoI and 6.41% for the UK in the 2012 determination.

[20] SEM Decision Paper on BNE Peaker for 2012. http://www.allislandproject.org/en/cp_decision_documents.aspx?article=a6ac980b-67cc-4f29-a786-a40ae5f7d28f

*Table A1: WACC estimate for BNE peaking plant in 2011*

| | RoI | UK |
|---|---|---|
| Risk-free rate | 5.50% | 1.75% |
| Debt Premium | 2.00% | 2.00% |
| **Cost of Debt** | **7.50%** | **3.75%** |
| Equity Risk Premium | 4.75% | 4.75% |
| Equity beta | 1.25 | 1.25 |
| **Post-tax Cost of equity** | **11.45%** | **7.70%** |
| Tax rate | 12.50% | 26.00% |
| **Pre-tax Cost of Equity** | **13.09%** | **10.41%** |
| Gearing | 60.00% | 60.00% |
| **Pre-tax WACC** | **9.74%** | **6.41%** |

*Sources: NIAUR, CER*

## A3 Approach

The nature of our analysis remains consistent with last year– we estimate the WACC parameters based on observable market data from reputable sources and ensure that our estimates are broadly aligned with relevant regulatory precedent, updated to consider any newly available information.

Although a broad range of academic and market evidence exists on the cost of capital for utilities, both in Ireland and the UK, the RAs continue to face a difficult task in determining a forward-looking estimate of the cost of capital for the BNE over its expected economic plant life since there is limited precedent of regulators setting a WACC for a generator subject to competitive and market constraints.

As such, it should be noted that regulators' decisions on the allowed WACC for regulated networks are not direct comparisons. A regulated network will typically be considered lower risk than the BNE, and an efficiently financed network will have locked in a portion of debt on its balance sheet at fixed rates, which, in the case of RoI, would be expected to be at lower rates that those currently available in the market. The notional BNE will, on the other hand, be financed by entirely new debt and equity taken out at current costs.

## A4 Gearing

Economic theory states the optimal level of gearing is the level of gearing at which the marginal interest tax shield benefit (arising from tax allowance) equates to the marginal default risk cost. In practice, however, regulators have not sought to estimate the optimal level directly and have instead tended to use a 'notional' level of gearing as a proxy for the optimal rate.

In our 2012 report, we noted that the Competition Commission ('CC') used an assumption of 60% gearing in the Bristol Water reference[21] while NIAUR had proposed a gearing assumption of 55% for the SONi price control consultation. NIAUR's retained the 55% gearing assumption for the SONi price control. The RIIO-T1 fast-tracked business plans from January 2012 take a notional gearing level of 55%, but this relatively low level reflects the exceptionally high levels of new capex relative to RAB. Overall, we do not consider that information since our last report presents a compelling case to change our assumption for the BNE and thus continue to recommend using a gearing assumption of **60%**.

## A5 Cost of debt

In this section we estimate the real cost of debt faced by an efficiently operating and financed BNE peaking plant.

### A5.1 Factors affecting how a BNE might seek to fund itself

An efficiently financed BNE peaking plant will look to adopt an 'optimal' debt structure that broadly matches the useful life of its assets, whilst minimising actual debt financing costs and mitigating various risks such as interest rate risk and refinancing risk.

As set out in the main report we have assumed that the plant life for the BNE will be 20 years i.e. an unchanged assumption from our 2010, 2011 and 2012 BNE reports. The broad expectation continues to be that the BNE would seek to match the maturity of its debt profile to the average useful life of its assets and would spread its debt maturity profile across a number of tenors – averaging around a 10 year maturity – in order to reduce the re-financing risk in any given year.

### A5.2 Risk-free rate (UK)

*Indexed-linked debt*

A commonly used source for risk-free rate estimates is the redemption yield on index-linked gilts (ILGs) issued by the UK Government. While ILGs are theoretically the best representative of the real risk-free rate, owing to the fact that they are seen as virtually free of default risk, there is a body of work which suggests that there may be some distortions in the ILG market owing to the Minimum Financing Requirement (MFR), which has created an amount of inelastic demand for ILGs (particularly of long maturities) by institutional investors such as pension funds. It is generally agreed that this distortion has led to lower yields being observed on long-dated ILGs than would have otherwise been the case.

A further influence depressing sovereign bond yields is the Bank of England's Quantitative Easing (QE) policy. In March 2009, the Bank of England introduced a programme of QE, initially involving the purchase of £75bn (subsequently raised to £200bn) of financial assets. A second phase of QE was introduced in October 2011 to raise the total of asset purchases under this scheme to

[21] http://www.competition-commission.org.uk/rep_pub/reports/2010/558Bristol.htm

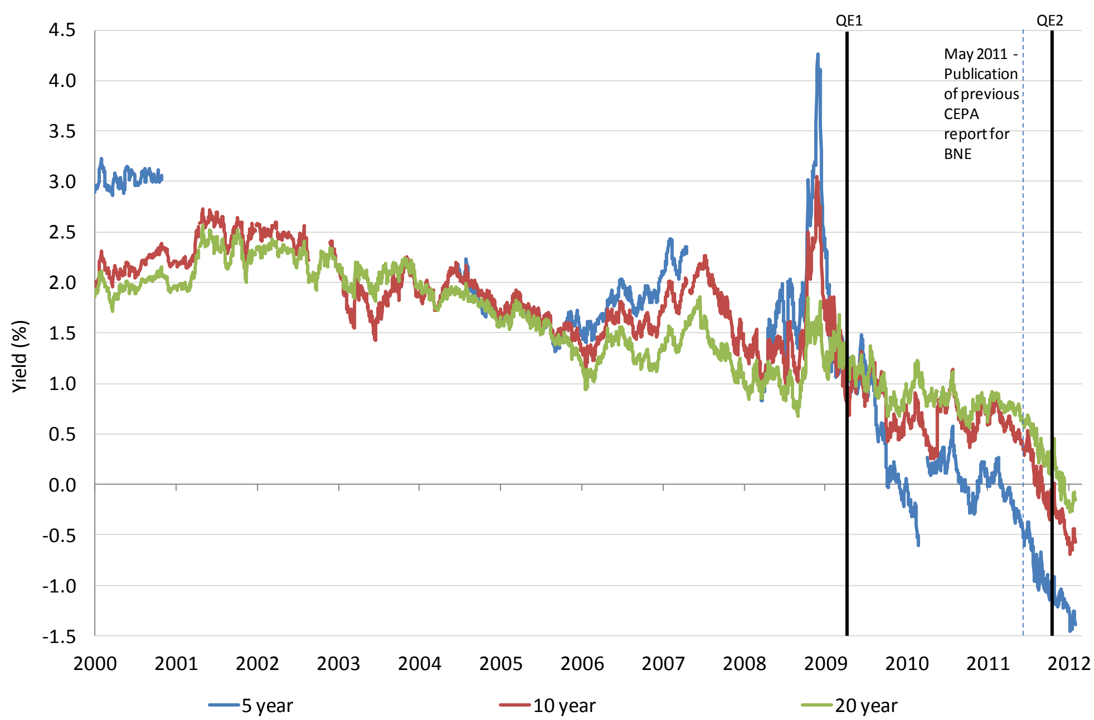
£275bn. This was increased to £325bn in February 2012. The extensive purchase of gilts has raised their prices and subsequently reduced yields. In a working paper by the Bank of England[22], they estimate the effect of Quantitative Easing was to decrease gilt yields by around 100bps. This depended on the maturities that were purchased in this scheme, as fewer purchases (and expectations of purchases) of longer-term gilts meant there was relatively less of an effect.

As a result, over-reliance on long-dated ILGs would likely result in an estimate of the real risk-free rate that was too low. Our analysis on the risk-free rate for the UK takes account of these comments.

We note that the CC in its Bristol Water determination noted that ILGs remain the most suitable source for estimating risk-free rates, and that long maturities appear most relevant since 'equities also have long (indefinite) maturity' and shorter-dated maturities may be affected by actions to address the recession. The CC went on to consider that long-dated ILG yields have remained constant at about 1% for five years, giving grounds to assume a lower risk-free rate. The CC also noted that there is no evidence for risk-free rates of over 2%, and thus set a range of 1% - 2%.

Figure A1 shows movements in the yields on benchmark ILGs over the past 10 years. Spot rates on 10 year ILGs are currently around -0.50%, below the 12 month trailing average of 0.13% and even more significantly below the 5 year trailing average of 1.00%.

*Figure A1: Yields on UK index-linked gilts*




*Source: Bloomberg*

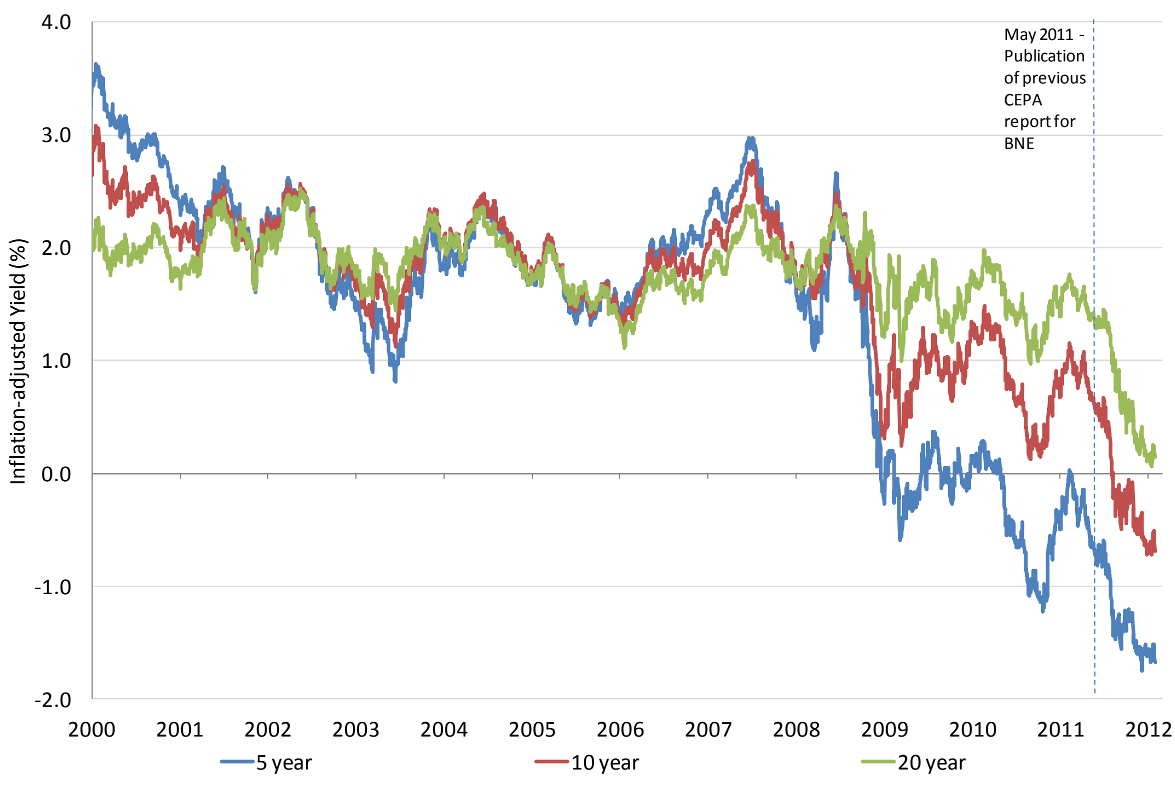
[22] Bank of England Working Paper No 393 (2010) 'The financial market impact of Quantitative Easing.'

*Nominal gilts*

Given the apparent distortion in the index-linked market, our preferred approach is to sense-check risk-free rate estimates derived from ILGs against estimates from nominal gilts. To do so requires us to deflate the nominal yields on gilts by a measure of expected inflation. Absent direct estimates of long-term Retail Price Index (RPI) inflation expectations, we deflate the nominal yield by an RPI inflation rate that is consistent with the Bank of England's inflation target of 2.0% on the Consumer Price Index (CPI) – namely 2.7%. It should be noted that this deflator is lower than the current 'break-even' deflator implied by longer-term ILGs and as such avoids the potential bias in using current break-even inflation rates.

Figure A2 shows the movements in the deflated yield on nominal gilts over the past 10 years. Here the historical downward trend is still quite clear. Spot rates on 10-year gilts are around 1.0% lower than at the time of our report last year (when they were around 0.3%) and well below the trailing average for the past 12 months (0.17%).

*Figure A2: Deflated yield on UK nominal gilts*



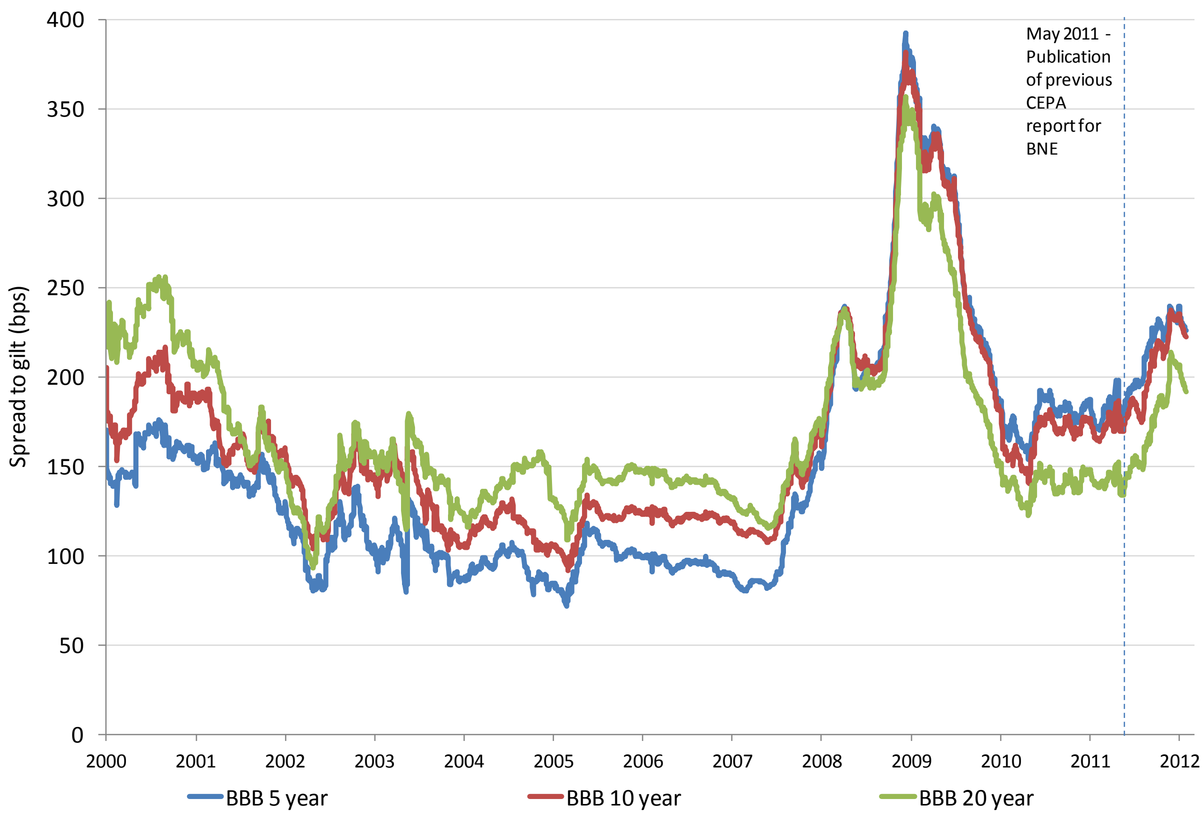

*Source: Bloomberg, CEPA analysis*

### A5.3 Debt premium (UK)

The debt premium is the cost above and beyond the risk-free rate which a company has to pay when borrowing in order to reflect that it is not completely free of default risk. Hence the debt premium is influenced by the company's credit rating. In line with our assumption that the BNE is a subsidiary of an international utility, we assume a credit rating of BBB, which is at the lower end of the investment grade spectrum.

Figure A3 shows the evolution of spreads (against benchmark gilts) for sterling denominated corporate debt with a BBB rating for different debt maturities. Following a spike in the debt premium around the time of Lehman Brothers' collapse, spreads had started to narrow, but have increased again since our 2012 report. The current spot rate on 10-year debt is around 222 basis points. This is slightly above the one year average of 194 basis points.

*Figure A3: Spreads on BBB rated UK corporate debt*




*Source: Bloomberg, CEPA analysis*

Table A2 overleaf shows evidence on recent issues of sterling denominated utility company debt raised in the UK.[23] It shows the (nominal) yield and spread at issue, as well as the current yield and spread as at 31st January 2012.

[23] We limit our evidence to utilities with a credit range of at least BBB and no higher than A.

*Table A2: Recent UK utility debt issues*

| Company | Issue date | Maturity | Amount (£m) | S&P credit rating | Spread at issue (bps) | Nominal yield on 09/02/12 (%) | Spread on 09/02/11 (bps) |
|---|---|---|---|---|---|---|---|
| Wales & West | 04/11/2011 | 2023 | 250 | A- | 197 | 4.11 | 186 |
| Wales & West | 04/11/2011 | 2028 | 150 | A- | 192 | 4.56 | 181 |
| Northern | 23/03/2010 | 2040 | 200 | BBB+ | 112 | 5.06 | 186 |
| EDF LDN | 17/10/2011 | 2041 | 1,250 | A- | 212 | 5.53 | 234 |
| Southern | 05/10/2011 | 2023 | 300 | BBB+ | 236 | 4.35 | 210 |
| NIE Finance | 02/06/2011 | 02/06/2026 | 400 | BBB+ | 239 | 5.65 | 304 |

*Sources: Bloomberg, CEPA analysis*

Following publication of the consultation for the 2012 BNE trading year calculation, NIE Finance carried out a bond issue in late May, which had an initial yield of 6.39% with a 239bps spread at issue. The evidence in Table A2 illustrates a higher yield on NIE debt compared, for example, to bonds recently sold by Northern Gas Networks and other GB utilities.

There are a number of characteristics of the NIE bond which might be considered drivers of this high coupon rate, which are individual to this issue, rather than necessarily evidence of investors requiring a premium for utility assets with a Northern Ireland connection.

For example:

- NIE issued this bond very soon after the acquisition by ESB and it appears likely that the bond was issued in relation to the acquisition.
- NIE issued a bond worth almost 40% of the company (on a regulated asset basis) at a point where there is uncertainty about future allowed funds owing to the timing of the ongoing price review.
- Typically efficiently financed companies would not seek to access debt capital markets in the run up to a price review determination i.e. when there is maximum uncertainty.
- Also you would not normally meet such a significant funding requirement through issuing one bond, i.e. the efficiently financed company might typically issue at a range of tenors and over a period of time.

As a benchmark and cross-check of this evidence, we have therefore considered evidence of debt costs for other energy utility companies in NI. Table A3 provides information on a Phoenix Gas BBB+ rated bond from 2009.

*Table A3: Evidence on Phoenix Gas bond*

| Category | Value |
|---|---|
| Issue date | 03/11/09 |
| Spread | 284.9 bps (compared to 5yr UK Treasury bonds) |
| Price | 107.503 |
| Yield (maturity) | 4.077 |
| Maturity date | 07/10/17 |
| Rating (Fitch) | BBB+ |
| Spread at issue | 250bps (compared to 7yr UK Treasury bonds) |

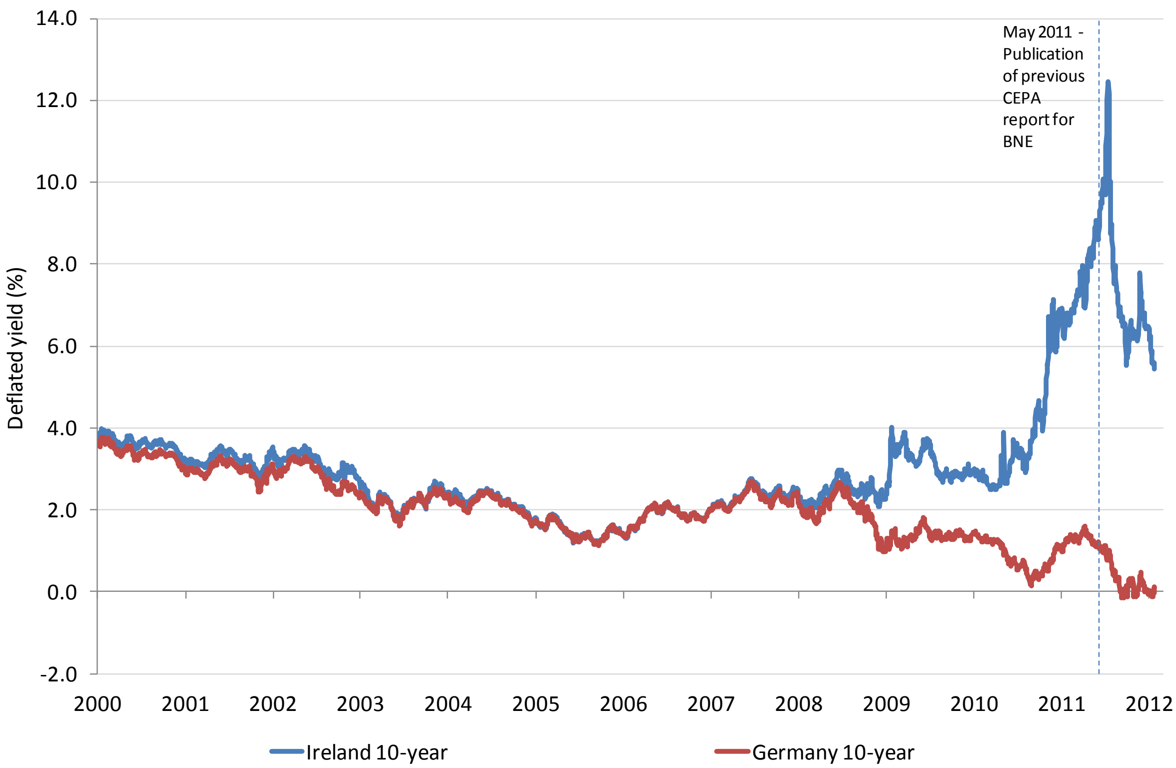
*Source: Bloomberg (figures as of 20 Feb 2012)*

The above would seem to provide evidence to support a premium on NI utility debt relative to debt issued by utilities from other parts of the UK. On balance, therefore, we believe there should be an additional 50bps on the top end of the range for the debt premium for the UK BNE compared to spreads implied by generic UK corporate bond indices.

## A5.2 Cost of debt for RoI – evidence of a Country Risk Premium

Prior to the breakout of the financial crisis in late-2008, there was a perception that investors treated sovereign risk as essentially identical anywhere inside the single Euro-zone currency zone. But as Figure A4 shows, the global financial crisis and more recently the Euro-zone sovereign debt crisis has resulted in what appears to be a structural break (Figure A4 plots the deflated yield on 10-year bonds issued by the governments of the RoI and Germany) – as is well documented, investors now view risk very differently in each Euro-zone member state, and for some of them, such as the RoI, the divergence with Euro-zone "core" countries such as Germany is significant, despite the gap narrowing compared to mid-2011.

*Figure A4: Deflated yields on 10-year Irish and German benchmark sovereign bonds*




*Source: Bloomberg, ECB CEPA analysis*

The sovereign debt crisis in Euro-zone member states has been widely commented upon both by policy makers and the investor community. The Financial Times commenting on the 8th February 2012 on recent developments in the Europe's capital markets noted:

> *"Traders and investors stress that the risk of a disorderly default by Greece and contagion across the eurozone remains. As one banker puts it, international investors are tip-toeing back into peripherals and they are being highly selective."* [24]

[24] Financial Times, 'Investors lured back to periphery debt', February 8th 2012

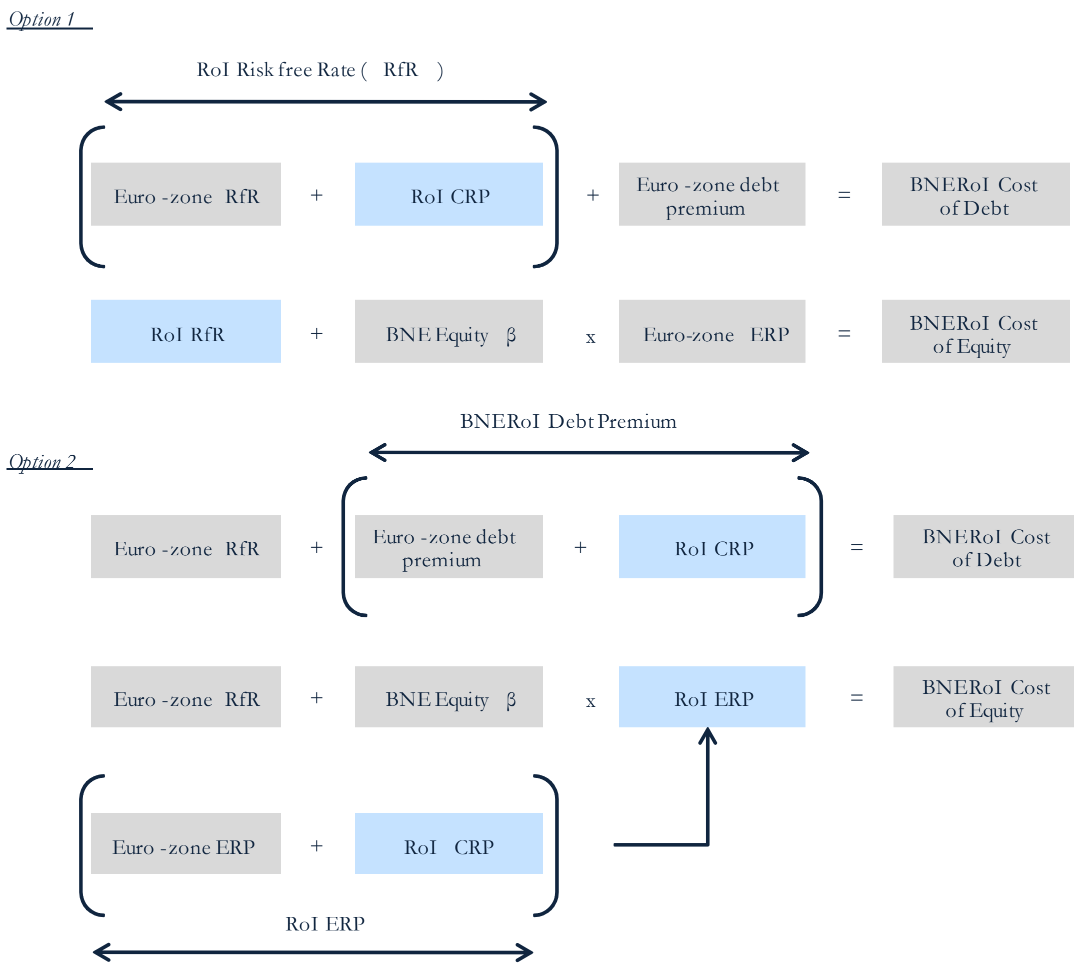
Given the ongoing debt crisis, the specific risk profile of RoI assets can be accounted for in calculating the WACC in one of two ways. The first would be to rely solely on information from Irish markets (including Irish government bonds for the risk-free rate and spreads on Irish corporate bonds for the debt premium). However, while this would represent the preferred solution, as we have noted in our 2009, 2010 and 2011 BNE reports, we consider this approach to be problematic, because the Irish market is relatively small and illiquid, for example, the RoI government bond market is much more shallow than the wider Euro-zone market.

The alternative approach is to rely on a wider range of information from across the Euro-zone, as mentioned in our 2012 BNE analysis, but to make an explicit adjustment to the risk faced by investors in the RoI by including a Country Risk Premium (CRP) in the WACC. To incorporate a RoI CRP, an adjustment could be made to the WACC in one of two ways:

- either to the risk-free rate; or
- to the risk premia for Irish assets (the debt premium and equity risk premium).

How the CRP is applied in the WACC calculation in each case is illustrated in the figure below.

*Figure A5: Adjustments to WACC calculation for risk profile of RoI assets*




We discuss each of the approaches in turn, while noting that a consistent approach needs to be used regardless of where the adjustment is made.

## A5.2 Risk-free rate (RoI)

*Conventional RoI sovereign debt*

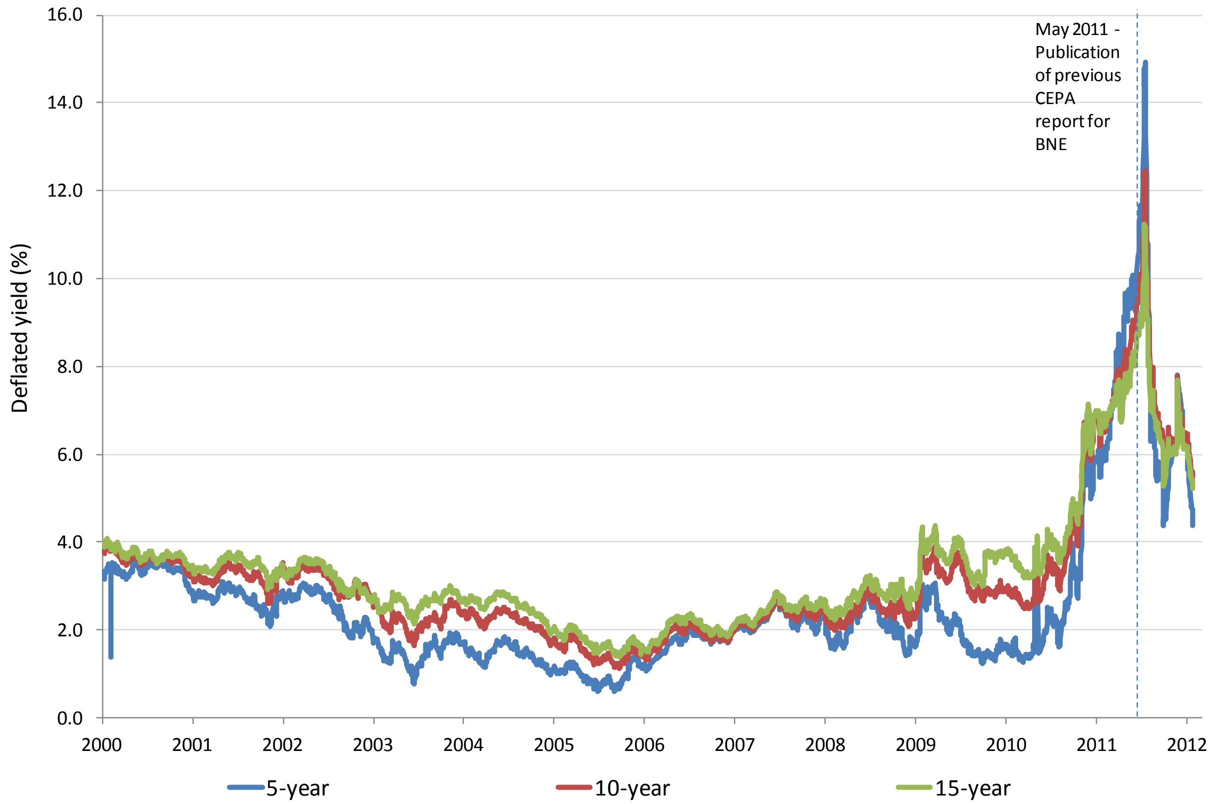
Figure A6 shows the deflated yield on Irish nominal bonds of different maturities over the past 10 years.[25] To convert nominal data into a real risk free rate requires deflating the observed nominal rates by inflation. This should be done using *expected* inflation rather than *actual* inflation since the yield on, for example, a nominal 10 year government security has built into it an assumption on the level of inflation that is *expected* over the 10 year life of the bond not the actual rate of inflation for the day the yield is observed.

[25] Note that there is insufficient data on 20-year Irish bonds.

While we acknowledge that Ireland has often seen very different inflation rates to the Euro-zone average,[26] absent any long-term inflation expectations specific to Ireland[27], we consider the best approach is to deflate Irish nominal bond yields by estimates from the European Central Bank's (ECB) Survey of Professional Forecasters.[28]

As Figure A6 shows, the sovereign debt crisis in the RoI (and other "peripheral" Euro-zone member states) has resulted in a large spike in the yield on benchmark Irish government bonds. Despite rising to over 12%, spot rates of the deflated yield on the 10-year bond are currently around 5.4%, compared to 7.1% at the time of our 2012 BNE report.

*Figure A6: Deflated yield on Irish nominal bonds*




*Source: Bloomberg, ECB, CEPA analysis*

In January 2012, the National Treasury Management Agency (NTMA) in Ireland conducted its first major issue since the November 2010 bailout by the IMF and EU. This was in the form of a swap, whereby over €3.5bn of bonds maturing in 2014 were exchanged for new bonds maturing in 2015. This equated to just over a quarter of government bonds set to expire in 2014.

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[26] Indeed, Irish Harmonised Index of Consumer Prices (HICP) inflation in December 2011 is estimated to be 1.7 per cent compared to 2.3 per cent in Germany.

[27] Shorter term forecasts for inflation in RoI, such as those provided by ESRI, are available.

[28] Long-term here is defined as five years and beyond. Note that the ECB does not have a specific inflation target but rather strives to achieve inflation that is "close to but below 2.0%".

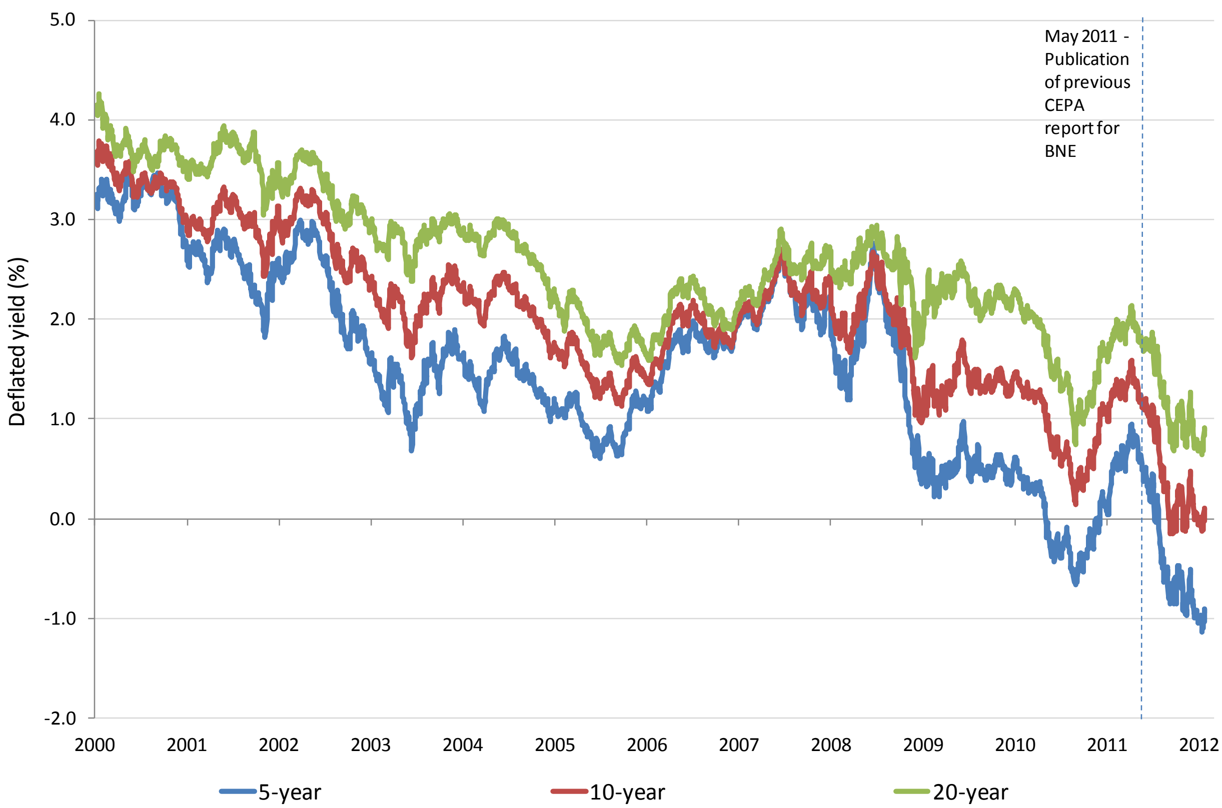
Although the newly issued bonds had a higher yield than what they were being swapped for (5.2 per cent rather than 4.9 per cent), we note this is considerably lower than could have been expected in the months preceding this.

*Euro-zone market evidence*

The most liquid sovereign debt market in the Euro-zone is Germany. Hence, we use benchmark German sovereign bonds to estimate the nominal risk-free rate for the wider Euro-zone economy, which we then also deflate by long-term inflation expectations taken from the ECB Survey of Professional Forecasters. Figure A7 shows the deflated return on benchmark German sovereign bonds for the past 10 years.

Current spot rates on the 10-year benchmark German sovereign bond are around 0.0%, substantially below the level observed around the time of our report last year (1.4%). The twelve month average for the deflated yield on 10-year German government bonds is around 0.7%. As context the average yield on 10-year German government bonds prior to the global financial crisis (January 2003 to September 2008) was around 2.0%

*Figure A7: Deflated yield on German benchmark sovereign bonds*




*Source: Bloomberg, ECB CEPA analysis*

*RoI relative to wider Euro-zone market evidence*

Table A4 shows average yields on 10-year government bonds in Ireland and Germany and the change in spreads prior to and following the global financial crisis and the sovereign debt crisis. The data shows that prior to the global financial crisis, the average yield on Irish and German government bonds was very similar. In the past 12 months, the yield differential in German and Irish sovereign debt has remained inflated with the spread on 10-year bonds issued by the governments of the RoI and Germany over 5% at the end of January 2012.

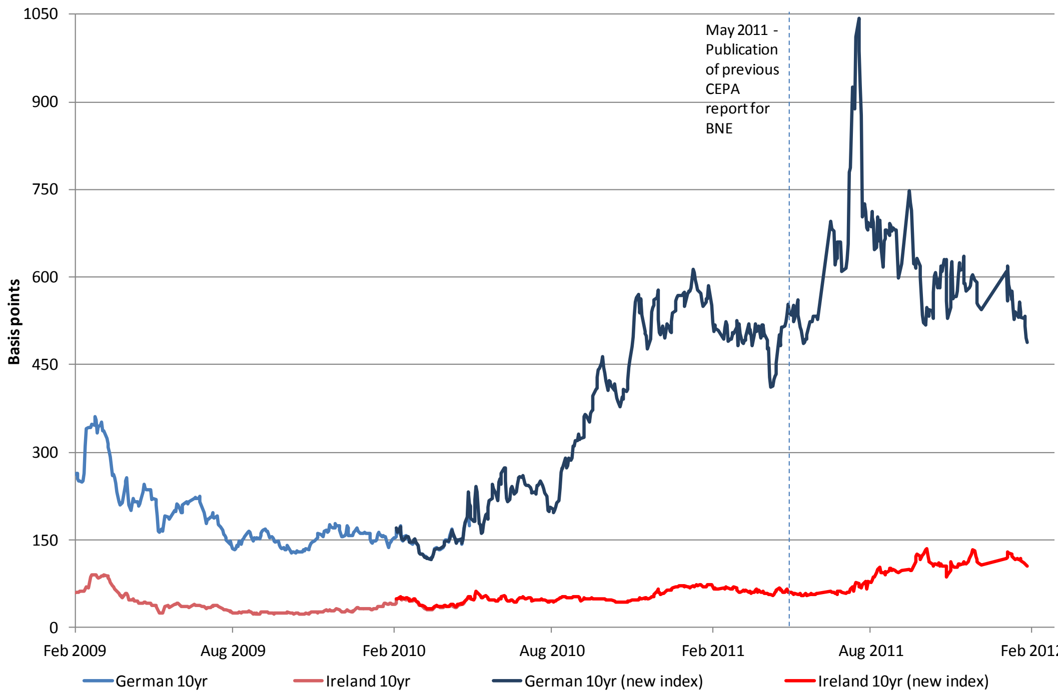
*Table A4: Average yields on 10-year government bonds in Ireland and Germany*

| **Period** | **RoI** | **Germany** | **Spread** |
|---|---|---|---|
| Spot (27th January 2012 ) | 5.44% | -0.02% | 5.46% |
| BNE Report 2012 (3rd March 2011) | 7.01% | 1.39% | 5.71% |
| 1-year average | 7.48% | 0.67% | 6.81% |
| Pre-crisis (3rd January 2003 – 15 September 2008) | 2.07% | 2.00% | 0.07% |

*Source: Bloomberg / CEPA analysis*

An alternative way of testing a CRP in the RoI risk free rate is to consider evidence from the market for credit default swaps (CDS). The derivative market for CDS developed to enable debt holders to hedge against the risk of a bond (or bond issuer) defaulting and also extends to sovereign debt. Figure A7 presents spreads on 10 year CDS for both Irish and German sovereign debt. The lower the spread in basis points the less risky investors perceive the threat of the debt defaulting.

*Figure A7: 10-year Irish and German Credit Default Swaps*[29]




*Source: Bloomberg, CEPA analysis*

Figure A7 shows that the spread on CDS for RoI and German government debt has widened significantly at times over the past 12 months, but currently remains close to its level for the BNE 2012 report. At the end of January 2012 the 10-year RoI CDS traded at a premium of 383 basis points to the equivalent 10-year German CDS. The twelve month average for the spread on RoI CDS compared to the German CDS was 501 basis points.

As illustrated in Table A4, the 12 month average for yields on deflated 10 year German nominal debt is around 0.7%. A RoI CRP of 200 – 600 basis points would be consistent with current evidence from the sovereign CDS market and from yield differentials in German and Irish sovereign debt markets.

Bringing this evidence together, this would imply a RoI risk free rate – incorporating a CRP – could lie anywhere in the range 4.25% - 9.75%. This is a very wide range for the risk-free rate, but reflects the uncertainty that continues to affect Euro-zone capital markets and specifically the borrowing costs of Euro-zone economies such as the RoI.

In contrast a euro-zone risk-free rate, based on evidence of rates for benchmark German sovereign bonds, is in the range 0.5% - 1.0% taking account of both current spot rates and average yields in the past twelve months.

[29] There is a discontinuation in the original Ireland and Germany 10 year index as reported by Bloomberg. The new index shows the latest data available from Bloomberg.

### A5.3 Debt premia (RoI)

Historically, there has been a shortage of data in the RoI to allow a direct inference of the domestic debt premium for Irish utilities. In previous BNE reports, we have therefore reviewed evidence of the spreads on Euro denominated corporate debt (with a BBB rating across different debt maturities) to arrive at an estimate of the debt premium in the RoI. This approach continues to be acceptable if a Irish CRP adjustment is made to the risk-free rate. However, if the adjustment is to be made to the debt premium then we must draw on the (limited) information that is available from the RoI market. In the sections which follow, we review market evidence on Euro-zone wide corporate debt and then some information on the debt premium paid by Irish utilities from individual issues and credit ratings over the past 12 months.

*Euro-zone wide market evidence*

Figure A8 shows the evolution of spreads (against Euro-zone benchmark sovereign bonds) for Euro denominated corporate debt with a BBB rating for different debt maturities. This data illustrates how spreads have remained elevated and currently are at levels above both their 1-year and 5-year historical averages.

*Figure A8: Spreads on BBB rated European corporate debt*


*Source: Bloomberg, CEPA analysis*

Table A5 shows information on the spot, 1-year and 5-year average for the debt premium on BBB rated Euro denominated debt.

*Table A5: Spreads on BBB Euro denominated debt (basis points)*

| | **Spot (27th Jan 2012)** | **1 year average** | **5 year average** |
|---|---|---|---|
| BBB 5-year | 253 | 212 | 196 |
| BBB 10-year | 217 | 196 | 209 |

*Source: Bloomberg, CEPA analysis*

Table A6 (overleaf) contains evidence on some of the issues of euro denominated utility company debt raised in the Euro-zone during 2011 and 2012. It shows the (nominal) yield and spread at issue, as well as the current yield and spread. As for UK issues, we again limit our analysis to issued debt of maturity up to 15 years.

*Table A6: Recent Euro-zone utility debt issues*

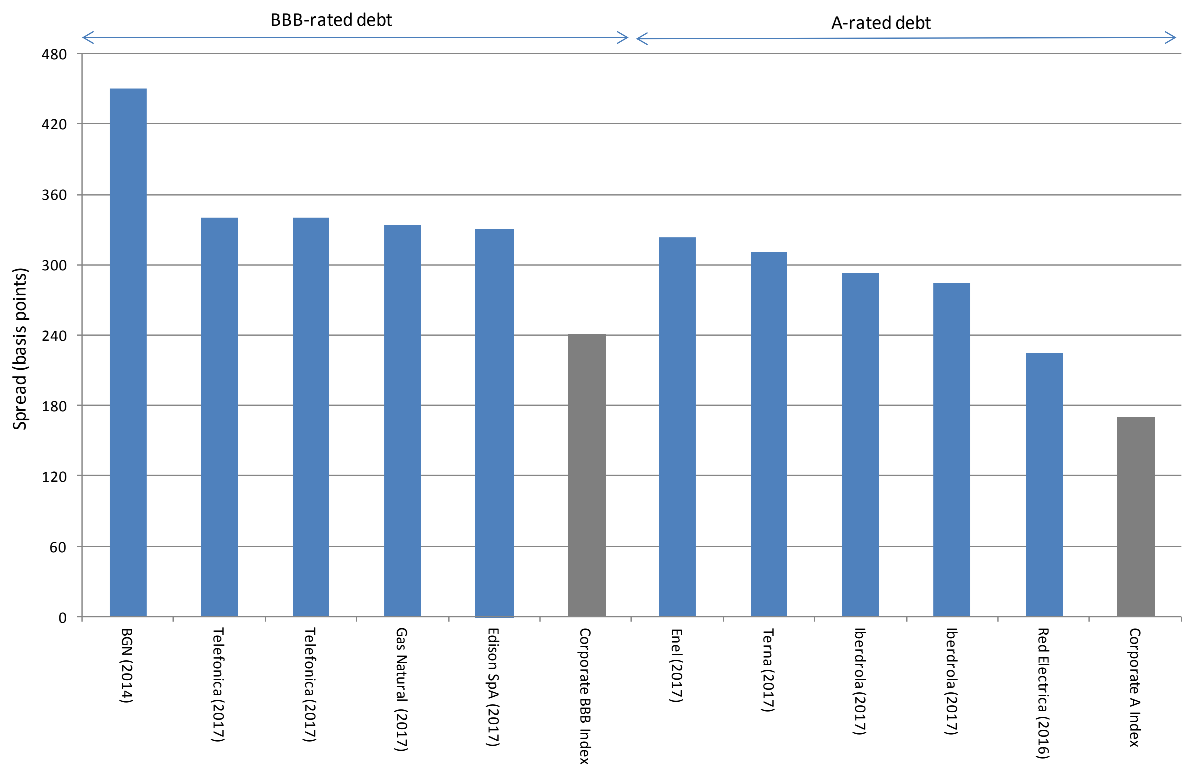
| Company | Issue date | Maturity | Amount (€m) | S&P credit rating | Spread at issue (bps) | Nominal yield (%) on 27/01/12 | Spread (bps) on 27/01/12 |
|---|---|---|---|---|---|---|---|
| Bord Gais | 16/06/2009 | 16/06/2014 | €550 | BBB+ /*- | 297 | 5.99 | 568 |
| Iberdrola | 10/02/2011 | 10/02/2014 | 750 | A- | 185 | 3.25 | 307 |
| Iberdrola | 07/04/2011 | 07/04/2017 | 750 | A- | 164 | 4.10 | 329 |
| Fortum | 24/05/2011 | 24/05/2021 | 500 | A | 104 | 3.17 | 147 |
| ENEL | 12/07/2011 | 12/07/2021 | 750 | A- /*- | 273 | 5.62 | 384 |
| ENEL | 12/07/2011 | 12/07/2017 | 1000 | A- /*- | 240 | 4.31 | 337 |
| SPD Finance UK | 18/07/2011 | 17/07/2026 | 403 | A- | 205 | 4.45 | 205 |
| Scottish & South | 14/09/2011 | 14/09/2021 | 345 | A- | 207 | 3.78 | 203 |
| ENEL | 24/10/2011 | 24/10/2018 | 1000 | A- /*- | 398 | 5.16 | 399 |
| ENEL | 24/10/2011 | 24/06/2015 | 1250 | A- /*- | 390 | 3.56 | 340 |
| Iberdrola | 25/10/2011 | 25/01/2016 | 600 | A- | 332 | 3.80 | 324 |
| EDF | 18/01/2012 | 18/01/2022 | 2000 | AA- /*- | 217 | 3.72 | 186 |

*Sources: Bloomberg, CEPA analysis*

*RoI relative to wider Euro-zone market evidence*

Figure A9 shows the *current* bond spread for Irish and other "peripheral" European economy utilities compared to generic BBB and AAA European corporate bond indices. Figure A9 shows that Irish and other "periphery" Euro-zone corporate utility debt currently trades at wider spreads than the cost of debt for generic Euro-zone corporate bond indices with an equivalent corporate credit rating. The spread in Figure A9 is calculated over benchmark sovereign bonds for the *Euro-zone* economy (as provided by Bloomberg).

*Figure A9: Bond spreads for European utilities*




*Source: Bloomberg, CEPA analysis*

We have also considered evidence from credit rating agencies who have commented on Irish utility credit risk and links to borrowing costs faced by the state.

For example, we note that in January 2012 Standard & Poor's maintained their credit rating for both BGN and ESB:

*On Jan. 13, 2012, we affirmed our 'BBB+/A-2' long- and short-term sovereign credit ratings on the Republic of Ireland and removed them from CreditWatch negative. The ratings now carry a negative outlook. Consequently, in our view, the risk of a sovereign rating action triggering a downgrade of Irish Utility Bord Gais Eireann (Bord Gais) has reduced. We are therefore affirming our 'BBB+/A-2' long- and short-term corporate credit ratings on Bord Gais and removing them from CreditWatch negative...*

*The ratings on Bord Gais reflect our assessment of the company's business risk profile as "strong" and its financial risk profile as "significant." The "strong" business risk profile is underpinned by Bord Gais' leading market position in the Irish natural gas market and its significant proportion of stable and predictable cash flows from its low-risk regulated gas transmission and distribution network operations…*

*These strengths are partially offset by the effects of increasing competition in the energy retail market, promoted by the Irish government. This competition has resulted in Bord Gais losing market share in the gas supply market and has prompted the company's expansion into the low-margin electricity supply market. Also mitigating the strengths is the risk that the economic downturn in Europe will have a negative effect on economic growth and energy demand in Ireland…*

*The negative outlook on Bord Gais reflects that on the sovereign and our opinion that a rating action on the sovereign is likely to result in a similar rating action on Bord Gais."*[30]

The commentary on the assessment of ESB reflected a similar view as Bord Gais:

*The ratings on ESB reflect our assessment of the company's business risk profile as "strong" and its financial risk profile as 'significant'...*

*Any further downgrade in Ireland's government bond ratings will cause Moody's to review ESB's ratings; the ratings of utility companies would normally be constrained by the rating of the country where most of their activities are located...*

*Our opinion (is) that there is a "moderate" likelihood that the Republic of Ireland would provide timely and sufficient extraordinary support to ESB in the event of financial distress."*[31]

ESB and Bord Gais' credit ratings illustrate that Irish utilities are able to obtain investment grade credit ratings but the sovereign debt crisis continues to affect the borrowing conditions in the economy. Indeed, this rating announcement makes a direct link between the rating outlook for utility companies themselves and the sovereign position in the RoI. We note however that these comments must be considered in the context of both ESB and Bord Gais currently being state owned Irish utility companies.

### A5.4 Regulatory precedent

In the UK and RoI since we compiled our report on the cost of capital for the 2012 trading year BNE, there has been further consultation regarding the SONI and RIIO determinations (note for RIIO Ofgem propose to utilise a debt indexation model for setting the cost of debt allowance). Table A8 summarises the risk-free rate, debt premium and overall cost of debt used in each of those determinations.

[30] Reuters (18 Jan 2012)

[31] Ibid

*Table A8: Recent regulatory decisions on the cost of debt*

| Regulator | Decision | RfR | Debt premia | Cost of debt |
|---|---|---|---|---|
| *United Kingdom* | | | | |
| NIAUR | NIE T&D proposals (2012-2017) | 2.0% | N/A | 3.2% |
| Ofcom | Wholesale mobile calls (2011-2015) | 1.5% | 1.5% | 3.0% |
| NIAUR | SONI [1] (2010 – 2015) | 2.0% | N/A | 3.5% |
| Ofgem | RIIO-GD1 / RIIO-T1 (2013-2021) | 1.4% - 2.0% | N/A [2] | |
| CC | Bristol Water (2010-2015) | 2.0% | 1.9 [3] | 3.9% |
| Ofgem | Electricity distribution (2011-2015) | 2.0% | 1.6% | 3.6% |
| Ofwat | Water & sewerage (2011-2015) | 2.0% | 1.6% | 3.6% |
| *Republic of Ireland* | | | | |
| CER | Electricity T&D (2011-2015) | WACC – 5.95% | | |
| CAR | DAA (2010-2014) | 2.5% | 1.6% | 4.1% |

*Note 1: Final decision paper*

*Note 2: Ofgem propose to use cost of debt indexation and only provides an estimate of the RfR for the cost of equity calculation*

*Note 3: Implied (CC only report total cost of debt for Bristol Water)*

As we noted in our 2012 BNE report, there appears to be consensus among UK regulators that a risk-free rate of 2.0% or lower is appropriate in a regulatory context. In the Bristol Water determination, the CC set a range of 1% - 2% for the risk free rate and used an estimate of 2% (at the top of the range) in its cost of equity decision. Ofcom in its recent mobile call termination decision uses a risk-free rate of 1.5%.[32] In the UK, there also appears to be regulatory consensus around the approximate level of the debt premium.

The most recent regulatory determination in the RoI is the electricity transmission and distribution price control where CER used a real pre-tax WACC of 5.95% (the individual parameters of the WACC were not provided). In the consultation paper, CER proposed to allow a real pre-tax cost of capital of 5% for the TSO, TAO and DSO over the 5-year price control (PR3). In its decision paper, CER highlighted the inherent uncertainty in estimating the WACC given the economic climate. In reaching its decision, CER noted that the cost of borrowing had increased substantially in Ireland and there was evidence from other European countries that the cost of debt for utilities had some correlation to the cost of debt faced by the state. Given the financial difficulties and the size of capital investment plans in the RoI's electricity networks, CER concluded that the cost of capital proposed in the consultation paper (5.0%) was not appropriate and allowed an uplift of 0.95% to the pre-tax WACC in its final proposals.

[32] http://stakeholders.ofcom.org.uk/binaries/consultations/mtr/statement/MCT_statement_Annex_6-10.pdf

## A5.4 Conclusions on the cost of debt

Table A9 brings together our view on the cost of debt faced by a notional BNE peaking plant in NI. Our range for the risk free rate is 1.50% - 2.00% and our estimate of the debt premium lies in the range 1.75% - 2.75%. An uplift of 50bps has been added to the top end of the range for the debt premium to account for a premium on NI utility debt compared to spreads implied by generic UK corporate bond indices.

*Table A9: Summary range for BNE cost of debt (UK)*

| Element | UK BNE 2012 | UK BNE Low | UK BNE High |
|---|---|---|---|
| Risk free rate | 1.75% | 1.50% | 2.00% |
| Debt premium | 2.00% | 1.75% | 2.75% |
| **Cost of debt** | **3.75%** | **3.25%** | **4.75%** |

*Source: CEPA analysis*

Table A10 summarises the cost of debt estimate for a notional BNE peaking plant in the RoI derived from adjusting the risk-free rate to include an Irish CRP in the range 2.0% - 6.0%. Consistent with applying a CRP to the risk free rate, the RoI debt premium is estimated from spreads on Euro-denominated utility and corporate bonds.

*Table A10: Summary range for BNE cost of debt (RoI) – CRP incorporated into risk-free rate*

| Element | RoI BNE 2012 | RoI BNE Low | RoI BNE High |
|---|---|---|---|
| Risk free rate | 5.50% | 2.50% | 7.00% |
| Debt premium | 2.00% | 2.00% | 2.50% |
| **Cost of debt** | **7.50%** | **4.50%** | **9.50%** |

*Source: CEPA analysis*

As a cross-check, Table A11 summarises our cost of debt estimate for a BNE in the RoI derived from a risk-free rate in the range 0.5% - 1.0%. This is based on evidence of spot and 12-month average rates for benchmark German sovereign bonds.

For the debt premium, a CRP risk premia of 1.0% - 2.0% has been applied to a debt premia range of 2.00% to 2.50% derived from evidence of Irish and other 'peripheral' European utility debt and generic Euro-dominated corporate bond indices respectively.

*Table A11: Summary range for BNE cost of debt (RoI) – CRP incorporated into debt premium*

| Element | RoI BNE 2012 | RoI BNE Low | RoI BNE High |
|---|---|---|---|
| Risk free rate | 5.50% | 0.50% | 1.00% |
| Debt premium | 2.00% | 3.00% | 4.50% |
| **Cost of debt** | **7.50%** | **3.50%** | **5.50%** |

*Source: CEPA analysis*

As is evident the different approaches of incorporating an Irish risk premia result in quite different ranges for the BNE cost of debt. We therefore recommend that the RAs take account of the evidence provided in both Table A10 and Table A11.

We propose that the appropriate cost of debt to allow a BNE peaking plant investment in the RoI for 2013 lies within the range 3.50% - 8.50%.

The top end of the range accounts for the uncertain and challenging financing conditions in the RoI but also that the BNE credit risk and borrowing costs, while likely to be correlated to the cost of debt faced by the state, is primarily related to participation in the SEM.

The bottom of the range reflects evidence of recent Euro-zone corporate borrowing costs including 'periphery' Euro-zone corporate utility debt currently trading at wider spreads that the cost of debt for generic Euro-zone corporate bond indices.

Our proposed range is summarised in Table A12 below.

*Table A12: Summary range for BNE cost of debt (RoI)*

| Element | RoI BNE Low | RoI BNE High |
|---|---|---|
| Cost of debt | 3.50% | 8.50% |

### A.6. Cost of equity

As discussed in Section A.3, we have employed the capital asset pricing model (CAPM) as the primary tool for estimating a notional BNE peaking plant's cost of equity. The CAPM defined cost of equity equation is presented below:

$$CoE = r_f + \beta_{Equity}(ERP)$$

where $CoE =$ cost of equity

$r_f =$ risk-free rate

$ERP =$ equity risk premium for the market portfolio

$\beta_{Equity} =$ equity beta, a measure of non-diversifiable risk of the security relative to the market portfolio.

The risk-free rate and equity risk premium (ERP) are economy-wide variables, whilst the equity beta is by definition company-specific. We use the same risk-free rate as derived above for the cost of debt, and update the estimates of the ERP and equity beta from last year's analysis based on the latest information.

#### A.6.1. Equity risk premium

The ERP is the extra return over the risk-free rate which investors require if they are to hold a portfolio of equities rather than risk-free securities alone. Estimation of the ERP is fraught with difficulties – it is a variable whose value cannot be directly observed and hence is one of the more contentious parameters estimated when determining a company's WACC. Complicating matters further is that few studies concur on what the true value of the ERP is, or even the correct method for estimating it.

Our approach in the 2010, 2011 and 2012 BNE report was to rely mainly on studies of the *ex post* 'excess returns' of a market portfolio over the historic risk-free rate. The value of the ERP measured in this way is sensitive to the period over which the average is measured, to whether the arithmetic or geometric mean is used, and to whether the market portfolio is made up of regional or global equities. This estimation method assumes that *ex post* excess returns are a fair reflection of the *ex ante* expected excess returns.

The most comprehensive and most commonly quoted source of *ex post* estimates of the ERP is the annual Credit Suisse Global Investment Returns Sourcebook, complied by Dimson, Marsh and Staunton. Table A12 summarises their most recent analysis for the 2012 Sourcebook. CEPA considers it prudent for regulators to take account of arithmetic mean averages, which are higher.

*Table A12: Dimson, Marsh and Staunton estimates of the ERP (relative to bonds)*

| Jurisdiction | Arithmetic mean 1900-2011 | Geometric mean 1900-2011 |
|---|---|---|
| United Kingdom | 5.0% | 3.6% |
| RoI | 4.8% | 2.8% |
| Europe | 5.0% | 3.7% |

*Source: Dimson, Marsh and Staunton*

While the 2012 Credit Suisse Sourcebook shows risk premiums of 3.6% (geometric) to 5.0% (arithmetic) we consider that our proposed range from last year (4.5% - 5.0% for *both* the RoI and the UK) remains appropriate as while in the short term values of the ERP of 5.5% or higher are not uncommon, a range of 4.5% - 5.0% is more representative of the medium and long term.

### A.6.2. Equity beta

A company's equity beta is a measure of the systematic risk faced by the company that cannot be diversified away from as part of an investor's balanced portfolio of assets. For companies with listed stock, it is measured as:

$$\beta_{Equity} = \frac{\text{cov}(r_e, r_m)}{\text{var}(r_m)}$$

where $cov(r_e, rm)$ = the covariance between the return on equity and the return on the market as a whole

$var(r_m)$ = the variance of the return on the market.

By definition, the market has a beta of 1.0.

Given that we maintain a notional gearing assumption of 60%, we see no reason to revise the equity beta range of 1.2 – 1.3 that we recommended for the BNE 2010, 2011 and 2012.

### A.6.2. Regulatory precedent

Table A13 summarises the cost of equity parameters used in recent regulatory decisions in the UK and RoI. We note that, with the exception of Ofwat's determination, the ERP used by regulators has been in line with our 4.5% - 5.0% range. We also note that equity beta levels have been at or below the lower bound of our range, although it is worth remembering that the equity beta is a company-specific parameter. For the current SONi price control decision paper, NIAUR uses the *total market return* (estimated as 6.75%) and an equity beta of 0.88 to derive a post-tax cost of equity of 6.17% for its price control proposals.

*Table A13: Regulatory precedence on cost of equity*

| Regulator | Decision | Risk-free rate | ERP | Equity beta | Cost of equity |
|---|---|---|---|---|---|
| *United Kingdom* | | | | | |
| NIAUR | NIE T&D proposals (2012-2017) | 2.0% | 4.8% | 0.9 | 6.32% |
| Ofcom | Mobile calls (2011-2015) | 1.5% | 5.0% | 0.76 | 5.30% |
| NIAUR | SONI [1] (2010-2015) | N/A | | 0.77 | 5.64% |
| Ofgem | RIIO-GD1 & RIIO-T1[1] (2013-21) | 1.4% - 2.0% | 4.0% - 5.5% | 0.65 – 0.95 | 4.0%-7.2% |
| CC | Bristol Water (2010-2015) | 1.0% – 2.0% | 4.0% - 5.0% | 0.64–0.92 | 3.6%-6.6% |
| Ofgem | Electricity distribution (2011-2015) | 2.0% | 4.7% | 1.0 | 6.7% |
| Ofwat | Water & sewerage (2011-2015) | 2.0% | 5.4%[33] | 0.9 | 7.1% |
| CAA / CC | Stansted airport (2009-2014) | 2.0% | 3.0%-5.0% | 1.0 – 1.2 | 5.0%-8.2% |
| CAA/CC | Heathrow airport (2009-2014) | 2.5% | 2.5%–4.5% | 0.90–1.15 | 4.8%–7.7% |
| CAA/CC | Gatwick airport (2009-2014) | 2.5% | 2.5%–4.5% | 1.00–1.30 | 5.0%–8.4% |
| *Ireland* | | | | | |
| CER | Electricity T&D (2011-2015) | WACC – 5.95% | | | |
| CAR | DAA (2010-2014) | 2.5% | 5.0% | 1.2 | 8.5% |

*Note 1: Consultation proposal*

[33] Ofwat specifically chose an ERP at the top end of its range in order to account for the uncertain economic environment at the time of its determination. However, it also noted that expectations of the future ERP were lower than the historical average.

### A.6.3. Conclusions on the cost of equity

For both the UK and RoI we have adopted a range for the cost of equity that accounts for the risks related to participation in the SEM and the location of the BNE plant based on common ranges for UK and RoI for the ERP and equity beta.

*Table A14: Summary range for BNE cost of equity (post-tax)*

| | RoI Low | RoI High | UK Low | UK High |
|---|---|---|---|---|
| Cost of equity | 7.90% | 13.50% | 6.90% | 8.50% |

*Source: CEPA analysis*

We therefore recommend that the appropriate cost of equity to allow a BNE peaking plant investment in the RoI for 2013 lies within the range 7.90% - 13.50% and for the UK in the range 6.90% - 8.50%.

## A.7. Taxation

CEPA is of the view that the WACC is not necessarily the most appropriate mechanism to allow for taxation costs and that there is merit in forecasting actual taxation costs and allowing for these through BNE costs estimation. However, we recognise that given the RAs have adopted a pre-tax WACC approach in previous determinations and that this is for a notional BNE, for which forecasting actual taxation cost would be difficult at best, there are benefits in terms of regulatory consistency of adopting a pre-tax approach for the current BNE determination.

Assessing a pre-tax WACC requires making an adjustment to the cost of equity using a 'tax wedge' based on a given tax rate. For simplicity we have used the statutory tax rates in each jurisdiction. That is, we use a rate of tax of:

- 12.5% for the RoI; and
- 24.0% for the UK.[34]

## A.8. Conclusion

At this stage of the determination process we have identified relatively broad ranges within which we believe the WACC input parameters for the BNE lie. Our current range estimates for the BNE peaking plant WACC are presented in Table A15.

[34] Applicable from 1 April 2012.

*Table A15: Consortium estimate of BNE weighted average cost of capital*

| | **RoI** | | | **UK** | | |
|---|---|---|---|---|---|---|
| | **2012** | **Low** | **High** | **2012** | **Low** | **High** |
| Cost of debt | 7.50% | 3.50% | 8.50% | 3.75% | 3.25% | 4.75% |
| Post-tax cost of equity | 11.35% | 7.90% | 13.50% | 7.70% | 6.90% | 8.50% |
| Taxation | 12.50% | 12.50% | 12.50% | 26.00% | 24.00% | 24.00% |
| Pre-tax cost of equity | 12.93% | 9.03% | 15.43% | 10.41% | 9.08% | 11.18% |
| Gearing | 60% | 60% | 60% | 60% | 60% | 60% |
| **Pre-tax WACC** | **9.67%** | **5.71%** | **11.27%** | **6.41%** | **5.58%** | **7.32%** |

## ANNEX 3: SINGLE ELECTRICITY MARKET WACC

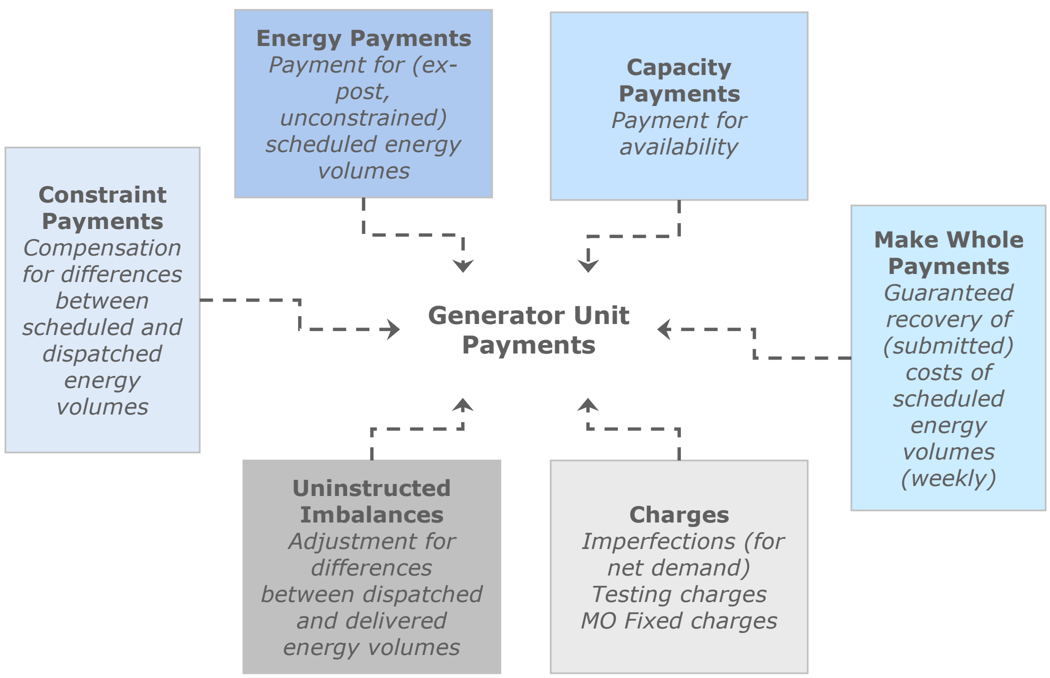
### Context

The SEM is a gross mandatory pool, similar to the pre-NETA trading arrangements for England and Wales and the existing and highly successful NordPool market in the Nordic region, combining NI and the RoI. In a gross mandatory pool like the SEM, all electricity generation and imports must be sold to the pool and all demand for electricity is bought back from it.

### Generator revenues

Generators operating within the SEM receive revenues through a variety of routes, illustrated in Table A3.1 below.

*Table A3.1: Energy payments within the SEM*




*Source: TSC helicopter guide/CEPA*

Of these revenue streams, revenues received from energy and capacity payments are likely to be amongst the most significant. The Capacity Payment Mechanism is therefore a crucial determinant of decisions both to enter and to leave the market, because it will drive financiers views on the long term viability of generation investment.

In the case of the BNE, the Capacity Payment Mechanism is the principle source of revenue for the BNE investor to cover the fixed costs incurred from (notionally) serving the final MW of demand at the point when the market is in equilibrium.

**BNE credit and investment risk**[35]

The SEM is an all-island market and therefore the risk of payment default by a market participant on their financial obligations in the SEM covers both NI and the RoI. The SEM, like other wholesale electricity markets such as the balancing mechanism in GB, has credit cover arrangements to ensure the financial integrity of the market.

Credit cover is collateral posted as a guarantee against a participant's potential exposures in the SEM and in the event of default, this credit cover can be utilised by the SEM market operator (SEMO) to satisfy the participants outstanding financial obligations to the market. Credit cover can take a number of forms including cash and letters of credit.

In the SEM credit risk is aggregated across all markets and payment streams managed by the SEMO. It includes not just the energy market, but also the capacity market, and any other amounts that serve to increase, or offset, these obligations. This is because the risk exposed by the market participant is an aggregate risk.

In the event that a SEM participant fails to make any payments due in the market, the SEMO will perform the following:

- inform the market participant of a shortfall;
- draw down on the lodged credit cover amount of the defaulting participant to cover the shortfall;
- if a participant credit cover is not sufficient to cover a shortfall then the amount not covered will be socialised among generators by reducing payments due to them by this amount, according to the value of their trading in that period;
- if unsecured bad debt, including interest, is recovered this amount will be paid to generators, according to the value of that trading period.

This means that were a RoI or NI market participant to fail to make payments due in the SEM (including capacity payments) and the participant's credit cover was not sufficient to cover the shortfall, then the unsecured loss would be socialised amongst all generation units in the SEM; those domiciled in NI and the RoI.

As capacity payments (the BNE's principle revenue stream) are funded on an all-island basis and covered by all-island credit cover arrangements, this implies that investment risk – driven by payment default in the SEM – of the BNE located in NI (RoI) is as much dependent on payment and credit risk of market participants domiciled in the RoI(NI) as NI (RoI).

**Single electricity market WACC**

[35] This section draws from SEMO – Credit Cover Overview – June 2010 http://www.sem-o.com/Publications/General/20100621_Credit%20Processes.pdf

The determination of an appropriate WACC is a key factor in the calculation of the annual BNE fixed costs. It was the view of a number of respondents to the 2012 BNE consultation paper that it was inappropriate to treat the WACC in the RoI separate from the WACC in NI (based on generic UK fundamentals).

This was an issue highlighted by most respondents with regards to the use of a UK WACC for a generator unit operating in a single cross jurisdictional electricity market. A number respondents argued the WACC for a BNE plant located in NI should reflect a unit operating in the SEM and therefore a blend of the NI and RoI WACC.

As discussed above, the circumstances of investing in a market that operates across two jurisdictions has relevance as it is the cash-flow risk of the investment which investors will in reality consider. However, CEPA has followed a methodology employed since the inception of the SEM and believe it would be a major methodological change to the way the capacity payment mechanism has historically been set were a single WACC approach adopted.

Based on the discussion above this change in methodology for calculating the BNE WACC should be considered further by the RAs.

**Impact of blended single electricity market WACC on BNE price**

We understand that a blended all-island WACC will be presented to the SEM Committee as an option for the final consultation paper. While not the only approach for deriving a single electricity market WACC this is one simple approach that could be adopted.

A blended SEM BNE WACC (weighted 70% RoI ; 30% UK)[36], based on the proposed cost of capital ranges in our main report, is illustrated in Table A3.1 below. This adopts a blend of the NI and RoI post-tax cost of equity which is results in different pre-tax WACCs for NI and RoI. The mid-point is adopted as a point estimate of the WACC ranges.

*Table A3.1 Blended all-island WACC*

| Element | RoI | NI |
|---|---|---|
| CoD (mid-point) | 5.4% | 5.4% |
| CoE – post tax (mid-point) | 9.8% | 9.8% |
| CoE – pre tax (mid-point) | 11.2% | 12.9% |
| **Pre-tax WACC** | **7.7%** | **8.4%** |

*Source: CEPA*

Table A3.2 shows the impact on the BNE price of adopting a single (before tax) all-island cost of capital assumption.

[36] The weightings are based on 2010 peak capacity in the two jurisdictions rounded to the nearest ten per cent: See Appendix 1 of the SONi / EirGrid Generation Capacity statement.

*Table A3.2: Costs of a BNE plant in the RoI or NI – all-island BNE WACC*

| Line Item | Unit | RoI Dual Fuel | NI Dual Fuel | RoI Distillate | NI Distillate |
|---|---|---|---|---|---|
| BNE cost (annualised) | €/kW | **128.15** | **117.18** | **96.13** | **96.67** |
| *Deductions* | | | | | |
| Inframarginal Rent | €/kW | | | | 5.54 |
| Ancillary service revenue | € 000/annum | | | | 848.4 |
| *Summary* | | | | | |
| **Estimated BNE cost** | **€/kW** | | | | **86.82** |

**Selecting a point estimate**

The analysis in the previous section adopted the mid-point of the RoI and NI ranges as the point estimate to derive the all-island WACC. This assumption is based on the RAs precedent of adopting the mid-point of the WACC range in previous BNE decisions. Should the RAs wish to consider calculating the BNE WACC on an all-island basis we note that with the proposed range for RoI WACC it may not necessarily be appropriate to adopt the mid-point as a modelling assumption (as adopted for Table A3.1).

Instead, based on the evidence in Annex 2, the RAs could consider adopting a point estimate towards the lower end of the RoI WACC parameter range given the BNE credit risk and borrowing costs, while likely to be correlated to the cost of finance faced by the state, will primarily be related to the risks associated with participation in the SEM.

Table A3.3 illustrates the impact on the BNE price of adopting a single (before tax) all-island cost of capital assumption where a point estimate is taken towards the lower end of the WACC range for the RoI as follows:

- CoD (RoI) – 4.0%
- CoE (RoI) post tax – 7.9%

The analysis illustrates that should the RAs consider a change in methodology for calculating the BNE WACC careful thought should be given to how a point estimate is derived from the RoI BNE WACC range proposed in Annex 2.

*Table A3.3: Costs of a BNE plant in the RoI or NI – all-island BNE WACC*

| Line Item | Unit | RoI Dual Fuel | NI Dual Fuel | RoI Distillate | NI Distillate |
|---|---|---|---|---|---|
| BNE cost (annualised) | €/kW | **118.95** | **107.13** | **87.05** | **86.57** |
| *Deductions* | | | | | |
| Inframarginal Rent | €/kW | | | | 5.54 |
| Ancillary service revenue | € 000/annum | | | | 848.4 |
| *Summary* | | | | | |
| **Estimated BNE cost** | **€/kW** | | | | **76.71** |