COSTS OF A BEST NEW ENTRANT PEAKING PLANT FOR THE CALENDAR YEAR 2012

A REPORT FOR THE REGULATORY AUTHORITIES

May 2011

Initial report

Submitted by:

Cambridge Economic Policy Associates Ltd in association with Parsons Brinkerhoff

CONTENTS

1. Introduction and context 1
1.1. Overview 1
1.2. Purpose of the initial report 1
1.3. CEPA and Parsons Brinkerhoff 1
1.4. The capacity payment mechanism 2
1.5. Structure of this document 3
2. Overview of CEPA/PB's approach 4
2.1. BNE calculation 4
2.2. Approach 5
3. BNE Technology selection 7
3.1. Approach 7
3.2. Long list of options 7
3.3. Initial filter 10
3.4. EPC costs and performance 12
3.5. Chosen technology option 15
4. Cost estimates 18
4.1. Types of cost 18
4.2. Location of the BNE plant 18
4.3. Investment costs 19
4.4. Recurring cost estimates 25
4.5. Summary 28
4.6. Summary 30
5. Economic and financial parameters 31
5.1. Approach 31
5.2. Estimate of BNE cost of capital 32
6. Infra-marginal rent and ancillary service revenues 35
6.1. Infra-marginal rent 35
6.2. Ancillary services revenue 35
7. Initial view of the BNE price 36
7.1. Additional modelling assumptions 36

7.2. Results 36
Annex 1: CEPA/PB Long-list of plant 38
Annex 2: Cost of capital for a BNE plant 39

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 2012 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 2012. 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 2012.

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 and 2011 trading years.

This report is intended to inform the RA's consultation on the BNE price for 2012. 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 and 2011 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 and 6,922 MW for 2011; and
- a price element which was €80.74/kW/year for 2010 and €78.73/kW/year for 2011.

The product of these price and quantity elements yielded an Annual Capacity Payment Sum (ACPS) for the 2011 trading year of €544,956,545.05.

1.4.2. Medium term review

CEPA and PB are aware that the RAs are currently undertaking a Medium Term Review (MTR) of the CPM. The main purpose of this review is to examine if the current design of the CPM can be further improved to optimally meet the objectives of the CPM (see Box 1.1 above). A recent consultation paper published by the RAs reviewed the BNE calculation methodology currently used within the CPM.[1] Issues covered by the MTR are outside the scope of this document. CEPA and PB have 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.

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.

[1] CER/NIAUR (2010): 'CPM Medium Term Review – Work Package 7: BNE Calculation Methodology'

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 third 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 two trading years (2010 and 2011). However, we have sought to fully reflect comments received from respondents if deemed appropriate and lessons learned from the previous two calculations as well as revisiting and refreshing our analysis in light of recent market developments.

2.1. 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 no market is in equilibrium and it is impossible 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.

2.1.1. 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 2012.

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 in

Key question	Other issues / questions to consider
What are the characteristics of a rational investor?	Is the investor independent or vertically integrated? Are they considering opportunities across the World, Europe or solely Ireland/ UK? What form of financial structure do they have? How would they finance an investment in a BNE plant?
What technology choice would the rational investor make?	What size is the plant? What specification (due to operational or environmental factors) does the plant have to meet? What trade-offs between efficiency and cost would they make? 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? What does that mean for fixed costs? What does this mean for operational costs?
Why would a BNE choose to enter the SEM?	Capacity payment revenues? Infra-marginal rent and ancillary services revenues? What is the required cost of capital?

Source: CEPA / PB

2.1.2. BNE methodology

The 2012 calculation will be the fifth 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.

2.2. Approach

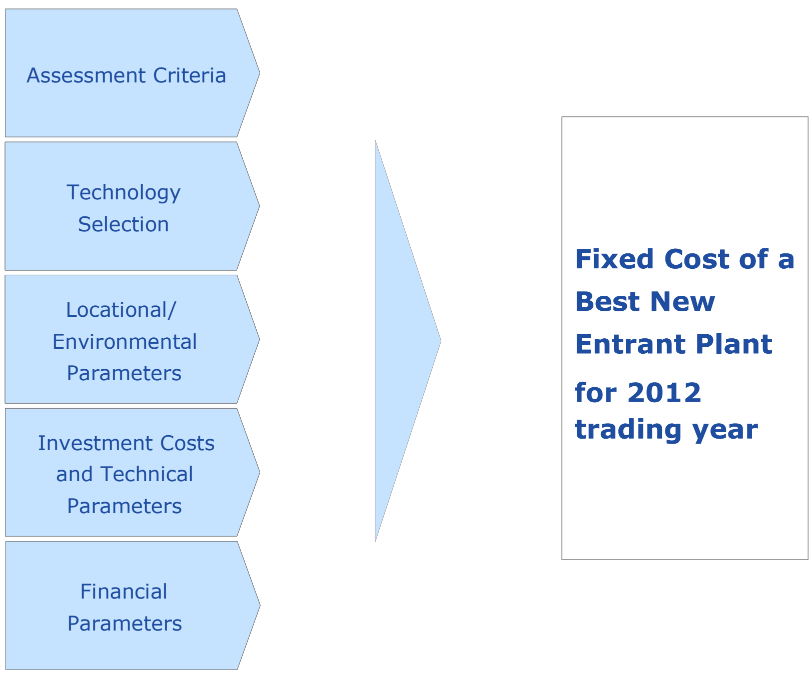
CEPA/PB are aware of the importance of the CPM to existing and prospective investors in generation and the consequences of the size of the CPM pot (the BNE price multiplied by the capacity requirement) for consumers. Our approach is consistent with that used in calculating the BNE price for the trading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

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 2012 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.

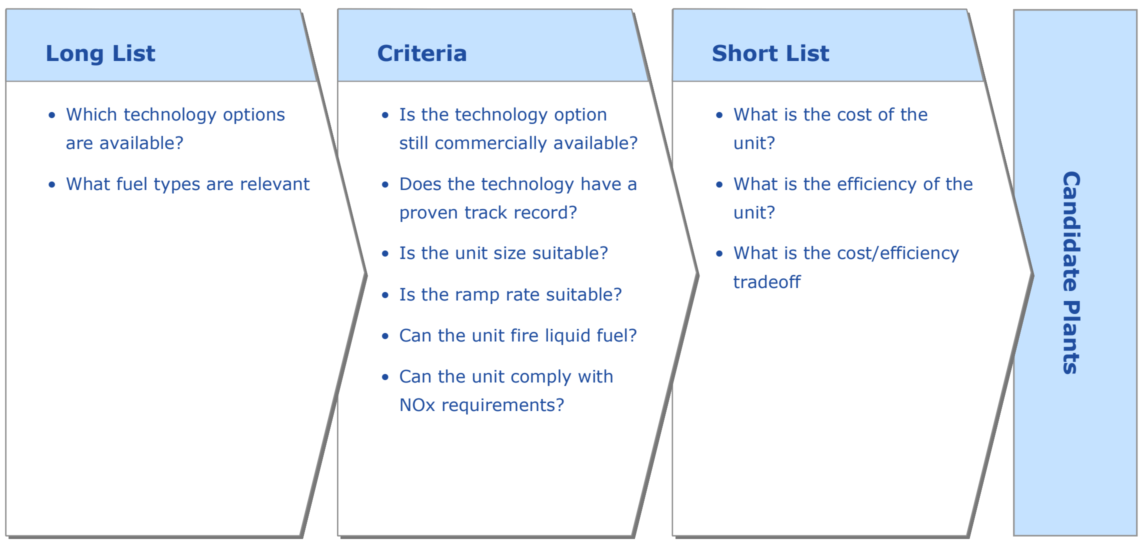
3. BNE TECHNOLOGY SELECTION

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 more promising 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 2012 has drawn from the conclusions previously reached through the 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 they 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.

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 (100 mg/Nm3).

The Directive on industrial emissions[2] (IED) came into force on 6 January 2011 and has set limits for GTs of 50 mg/Nm3 NOx for gas-firing and 50 or 90 mg/Nm3 NOx for liquid fuel firing. The 90 mg/Nm3 limit will apply if a plant has been awarded a Permit no later than two years following the commencement of the IED (or has applied within two years and is operational within three years after commencement). For any other circumstances 50 mg/Nm3 will apply for liquid fuel fired GTs. Since the BNE 2012 plant would be operational by 2013, the 90 mg/Nm3 NOx limit applies.

The emissions requirements that the plant must be capable of meeting 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)
Distillate Firing	90	100
Gas Firing	50	100

Source: Directive on industrial emissions

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).

For the 2010 and 2011 calculation CEPA and PB (via the RAs) sought the views of the TSOs about the appropriate assessment criteria.

Eirgrid noted that the proposed range of plant sizes of 30 – 200MW was very wide. However, they note that the lower end reflects a scale that is of practical use to system operators while the upper end reflects medium sized units which retain large elements of flexibility. Eirgrid noted the increasing importance of flexible plant for system operation and suggested it may be appropriate to consider ramping rate of plants (e.g. MW/min) rather than the time taken to reach full load as a criteria. In general, Eirgrid agreed with the proposed criteria and felt they were reflective of their requirements.

SONI noted a need for all plant, including second hand plant, to comply with its Minimum Functional Specification and suggested that all criteria should be reflective of this specification.

CEPA and PB consider that the assessment criteria used in last year's calculation remain fit-for-purpose. 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. We do not see a rationale for revisiting the criteria.
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.

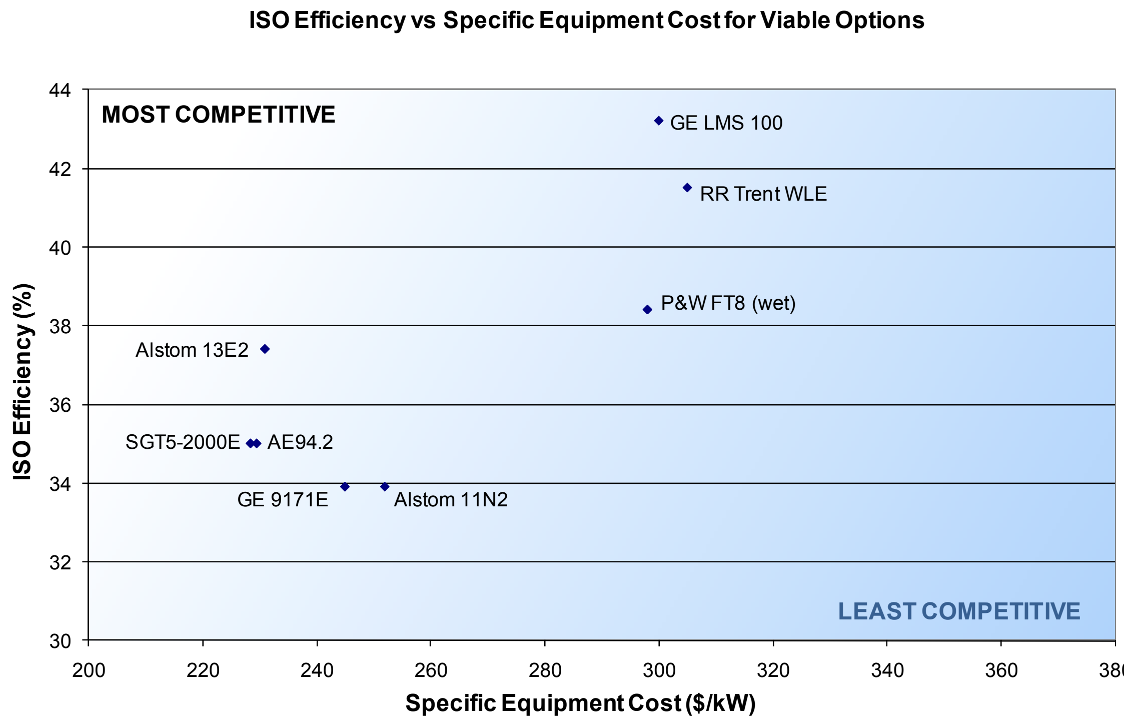
3.3. Initial filter

On the basis of the filtering process outlined above, we identified a series of plant which fulfilled these criteria. 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.

We note that during the BNE process for the 2010 trading year, 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 have reflected it in the approach taken in shortlisting plant for the 2012 trading year.

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

Figure 3.2: 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 towards the left-hand side of 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 aeroderivative GTs shown in Figure 3.2 were considered in the candidate plant selection process.

3.3.1. Candidate plants

Having applied the filters described above and removed the plant towards the right of competitive similar plant in Figure 3.2 (including the slightly smaller, less efficient and higher specific cost GE 9171E and Alstom 11N2 gas turbines), we identified the most practicable generating unit options for the BNE technology. In order to ensure a robust analysis, the aeroderivative GTs with the best specific equipment cost were also included such that the effect of any relative performance improvements from water injection or EPC cost advantages of containerised systems might be captured. The candidate plant list was increased from four candidate GTs to five, and their arrangements are as follows:

- 1 x Siemens SGT5-2000E
- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2

- 3 x Pratt & Whitney SwiftPac 60 (wet)
- 2 x General Electric LMS100PA

In our analyses we have included the Alstom GT13E2, the plant selected as the BNE plant last year. We have also included the Siemens SGT5-2000E (selected for BNE 2009) and the Ansaldo Energia AE94.2, which has its origins in the same GT design as the SGT5-2000E. The selected aeroderivative GT plants comprise of the P&W SwiftPac 60 and the GE LMS100PA, both of which appear to be being actively considered by investors in the SEM.

Similar to last year's modelling we have included the increase in power output resulting from the use of water injection for NOx control 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.

Included as part of this year's methodology, we have provided all 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. The reason for doing this is to allow for more accurate estimates of the gross power output for the GTs under consideration. The use of water injection for NOx control introduces a variable for which either OEMs may not have provided sufficient curves to Thermoflow or for which the platform used by Thermoflow may not be able to model accurately the performance for certain GT models. Where responses have not been received from the OEMs, the Thermoflow results have been used as is. 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. The values provided by Siemens were used 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

We have seen a significant reduction in tendered EPC prices relative to last year. The long implementation times of most power plants as well as the delay in the perception of reduced electricity demand has meant that the downturn in the power industry had a significant lag relative to most markets. In contrast to the global price trends produced by Gas Turbine World, in which the reduction of simple cycle plant prices from mid-2009 to mid-2010 dropped by more than 10%, and was more significant than for combined cycle plants, we have seen a more significant drop in CCGT plant prices. The highly competitive large CCGT market has more comparable offerings from the OEMs than the medium-sized GT market, for which GT capacities are generally staggered and performance/cost benefits differ significantly.

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.

GT PRO Version 20 was used to model the candidate plants and the models were then used in the cost estimation process. The post-September release of Version 20 contains updated cost estimate multipliers that in general yield lower estimates for EPC prices.

The reduction in EPC cost estimates based on the use of appropriate default multipliers in Thermoflow's PEACE software yields differing percentages for the various candidate plants. A greater reduction is evident in the aeroderivative GT plants (representing an appropriate shift based on market evidence), but less of a reduction on the industrial GT plants (previously selected as BNE plants for the SEM) compared to the average price trend given by Gas Turbine World.

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 overleaf (using NI as the basis, there is a slight difference in EPC costs 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). 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.

We note there has been a slight increase in the lifetime output of a number of candidate plants from our 2011 BNE report. This is driven by requirements for greater water injection to meet IED environmental limits on NOx. Changes to average lifetime output are based on the final release of GT Pro Version 20 and consultation with plant manufacturers.

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

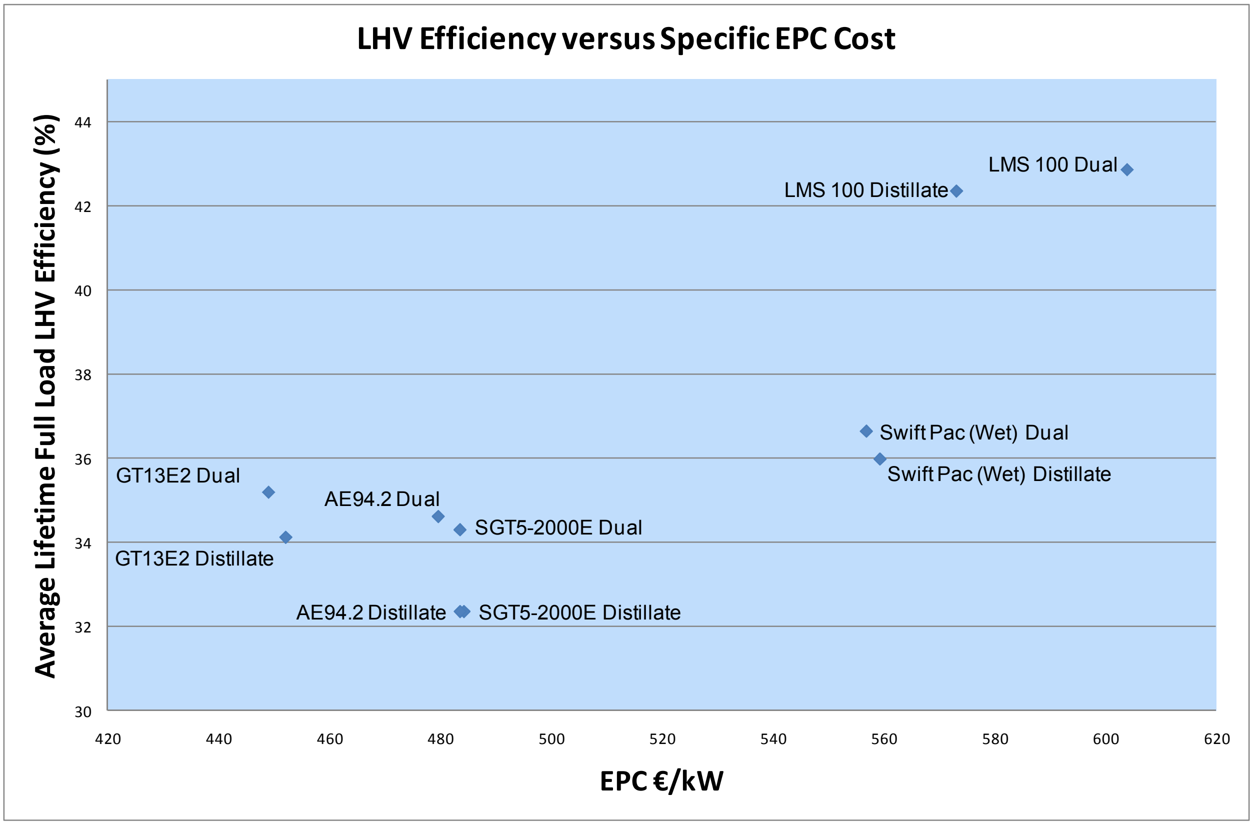
Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)[3]
1 x Alston GT13E2	Distillate	192.5	87.0
	Gas	193.9	87.1
1 x AE94.2	Distillate	166.4	80.5
	Gas	167.7	80.4
1 x SGT5-2000E	Distillate	166.4	80.6
	Gas	167.7	81.1
3 x SwiftPac 60	Distillate	183.8	102.8
	Gas	185.1	103.1
2 x LMS 100	Distillate	195.3	111.9
	Gas	193.5	116.8

Source: CEPA/PB

To compare these options on a specific EPC cost basis, the costs are plotted against efficiency in the chart below (Figure 3.3). Once again, the efficiencies reflect the impact of water injection. 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.

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

Figure 3.3: 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.

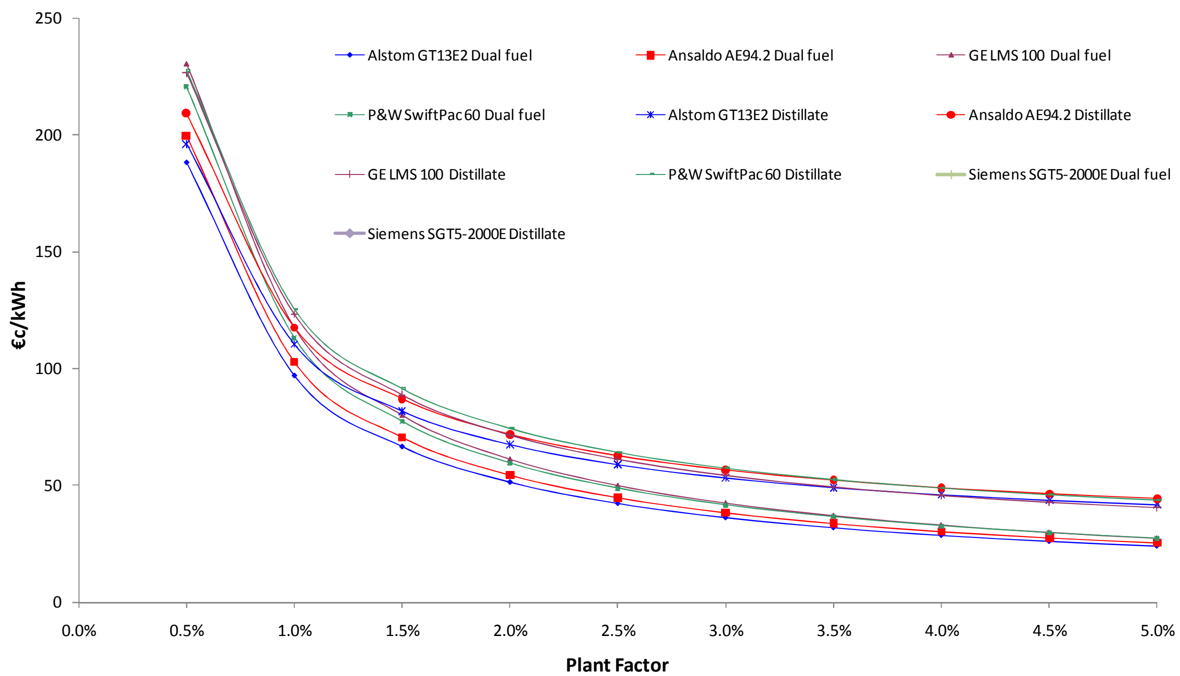
Table 3.4: Specific EPC cost estimates for short-listed plants in NI.

Plant Type	Fuel Type	EPC Cost €/kW
1 x Alston GT13E2	Distillate	452.2
	Gas	449.1
1 x AE94.2	Distillate	483.6
	Gas	479.7
1 x SGT5-2000E	Distillate	484.3
	Gas	483.6
3 x SwiftPac 60	Distillate	559.3
	Gas	556.8
2 x LMS 100	Distillate	573.1
	Gas	603.8

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 2010 and 2011 we have undertaken screening-curve analysis. The results of this analysis are shown in Figure 3.4.

Figure 3.4: 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 2012 is an Alstom GT13E2**. This plant has a capacity of 193.9MW 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. The water injection rate is required to achieve the 90mg/Nm3 NOx limit.

- 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 and 2011) 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 and 2011 BNE report, there appears to be significant interest in investment in power capacity in both NI and the RoI despite the economic downturn. In the RoI the past year has already seen the addition of two large CCGT plants in Cork, and two new OCGT units at Edenderry. Four new OCGTs are due to connect to the system over the next 4 years.

Table 4.1 lists thermal generators that have signed agreements to connect to the island over the next few years. These generators are all due to connect in the RoI.[4] A connection offer for a 440 MW CCGT generator in Co. Louth has also been signed and Endesa have plans to commission new plant immediately after the closure of the existing units at Great Island and Tarbert.

Table 4.1: Plant commissioning

Plant	Date	Capacity (MW)
Meath Waste to Energy	Feb 2011	17
Nore Power	Apr 2012	98
Dublin Waste to Energy	Dec 2012	72
Cuilleen OCGT	Jan 2013	98
Suir OCGT	Jan 2014	98
Caulstown GT	Apr 2014	55
Knocknagreenan pumped storage	Jun 2014	70

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 Belfast West 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.

[4] EirGrid / SONi (2010): 'Generation Adequacy Report 2011-2015'

Table 4.2: EPC cost estimates for NI and RoI

Plant	Fuel type	EPC Costs (€)
NI	Distillate	€87,037,000
	Dual	€87,077,000
RoI	Distillate	€88,155,000
	Dual	€88,197,000

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 the 2010 and 2011 decision, been estimated at 18 months. While 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%.

Recent research, also by Knight Frank Ireland, notes that the price of Irish farmland now seems to have stabilised:

> "*we are seeing agricultural land prices now stabilising after significant drops approaching 50% in the years 2008 and 2009 … it is clear from the survey that land is now beginning to sell again at auction.*" [5]

In the 2011 BNE report we used a notional rate of €150k/acre for suitable greenfield land in the RoI. 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 2012 BNE calculation as while market commentary suggests that agricultural land values may have stabilised, we have seen no 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.

[5] http://www.knightfrank.ie/documents/landsalessurveyaugust2010.pdf

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. This assumption is supported by the Utility Regulator's recently closed consultation on Vacant Sites within the NIE Land Bank.[6]

As we noted in our 2011 BNE report, the Belfast Harbour Estate is owned by two landowners (Belfast City Council and Belfast Harbour Commissioners) 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.

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	€1,451,532
	Dual	20,500	€1,437,508
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.

4.3.5. Electrical connection costs

A significant driver of the costs of a site is the electrical connection costs the site would face. As in previous years, we have contacted the TSOs to understand the costs for our BNE sites in the RoI and NI, for which the transmission voltages 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 original estimate for movements in metal prices. 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

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

most recent decision on transmission charges and timelines.[7] As for NI, we have updated our 2011 estimate for movements in metal prices.

The estimate of electrical connection costs in both jurisdictions is summarised in Table 4.3 below.

Table 4.3: Electrical Connection Cost Estimates

Location	Electrical Connection Costs (€)
NI	€7,720,000
RoI	€6,930,000

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. For the Belfast West site, a water main runs adjacent to the site and consequently, no costs have been allocated for the water connection beyond the battery limit. For the gas connection, estimates from Gaslink received in developing the BNE price for 2010 have been 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 4.4: Gas and raw water connection costs

Location	Cost of water connection (€)	Cost of gas connection (€)
NI	0	€1,810,000
RoI	€450,000	€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 4.5: Owners contingency

Location	Fuel Type	Owners contingency (€)
NI	Distillate	€4,525,924
	Dual Fuel	€4,528,004
RoI	Distillate	€4,584,060
	Dual Fuel	€4,586,244

[7] http://www.cer.ie/GetAttachment.aspx?id=0e95c64f-80f9-4487-b9c9-88f56b8209a5

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.

Our estimates are provided in Table 4.6 below.

Table 4.6: Financing, interest and insurance costs

Element	Total cost for distillate (€)	Total cost for duel fuel (€)
Financing NI	€1,740,740	€1,741,540
Financing RoI	€1,763,100	€1,763,940
IDC NI	€1,815,350	€1,841,380
IDC RoI	€3,795,276	€3,911,362
Construction Insurance NI	€783,333	€783,693
Construction Insurance RoI	€793,395	€793,773

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.*[8]

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.[9] 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 €4.41m for a distillate plant and €3.69m 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$119.21/barrel[10]. It is assumed that this fuel is sold back at the end of the plant life.

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

[9] 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

[10] Oil price used was ICE Brent Crude as traded on 1st April 2011 (sourced from CEPA Bloomberg subscription).

Our cost estimate for fuel working capital is provided in Table 4.7 below.

Table 4.7: Initial fuel working capital

Element	Total cost for distillate (€)	Total cost for dual fuel (€)
Fuel working capital	€4,413,073	€3,694,292

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 4.8: Other non-EPC costs

Location	Fuel type	Other non-EPC costs
NI	Distillate	€7,833,330
NI	Dual fuel	€7,836,930
RoI	Distillate	€7,933,950
RoI	Dual fuel	€7,937,730

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 slight compared to the previous year costs as shown in Table 4.9 below.[11]

Table 4.9: 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

[11] http://www.sem-o.com/Publications/General/2010-11%20SEMO%20Tariffs%20and%20Imperfection%20costs.pdf

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.

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.

Table 4.10 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 4.10: Market operator charges

Type of charge	Charge amount	Total Cost
Fixed market operator tariffs	€ 107.00	Distillate - € 20,598 Dual - € 20,747

Transmission Use of System Charges

The RoI and NI take different approaches to calculating capacity charges. While we understand that a project to harmonise charges has been considered, we have assumed that the existing differential approaches continue for 2011 and we use the most recent tariffs as the best estimate of the tariffs which the BNE plant will face.

The differential approaches to calculating capacity charges in the RoI and NI are as follows:

- In NI, TUoS charges are approved by NIAUR and designed to recover the NIE Transmission Revenue Entitlement. Charges are available from SONI's charging statement, which was updated in August 2010[12]. For the period 1 October 2010 to 30 September 2011, the charge is £250.37/MW per month. We propose to use this figure, converted at a €/£ exchange rate of 1.1317, for the purposes of the BNE calculation.
- In the RoI charges to generators connected to the system are based on the generator's capacity and are site specific, differing according to the location of the generator. For

[12] http://www.soni.ltd.uk/upload/TUoS%20CHARGING%20STATEMENT%202010-11%20v1.3.pdf

conventional generation, Generation Network Location-Based Capacity Charges vary between €0.00/kW/annum and €10.30/kW/annum.[13] Because we are using a notional location it is not possible to quote a TUoS charge for a given site. We therefore propose to use a figure of €5.15/kW/annum, representing a midpoint of this range.

Our estimates of electricity transmission capacity charges are summarised in Table 4.11 below.

Table 4.11: TUoS charges

Location	Fuel Type	TUoS charge (€)
NI	Distillate	€656,490
	Dual Fuel	€661,265
RoI	Distillate	€991,789
	Dual Fuel	€999,002

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. Similar to last year we have assumed that on a peak day the BNE plant would run for 4 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 2011/12 gas year.

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[13] http://www.eirgrid.com/media/2010-2011%20Statement%20of%20Charges%20-%20Approved%20by%20CER%20-%20Published%2030%2009%2010.pdf

[14] Similar to the response document 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/index.jsp?p=289&n=180

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

Table 4.12: Gas transmission charges

Jurisdiction	Cost per kWh [1]	Plant size (MW)	Efficiency (%)	Assumed hours run	Transmission charge
NI capacity	£0.32590	193.9	35.19%	4 hours [2]	€902,920
RoI (capacity)					
Onshore	€ 0.446809	193.9	35.19%	4 hours [2]	€1,617,371
Interconnection	€ 0.21583				

Note 1: Peak day capacity

Note 2: Per peak day

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 €461,000 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 €1,330,000 and for the dual fuel option, €1,355,000. 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 4.13: Fixed operation and maintenance costs

Fuel type	O&M Costs (€)
Distillate	€1,791,000
Dual fuel	€1,816,000

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 4.14: Insurance costs

Fuel Type	NI (€)	RoI (€)
Distillate	€1,392,592	€1,410,480
Dual Fuel	€1,393,232	€1,411,152

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

Table 4.14: Annual business rates

Fuel Type	NI (€)	RoI (€)
Distillate	€631,479	€1,507,316
Dual Fuel	€636,072	€1,518,278

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.

[17] http://www.dfpni.gov.uk/lps/index/property_rating/rate-poundages-2011.htm

Table 4.15: Investment cost estimates (€)

Fuel Type	**NI Distillate**	**NI Dual Fuelled**	**RoI Distillate**	**RoI Dual Fuelled**
EPC costs	€87,037,000	€87,077,000	€88,155,000	€88,197,000
Site procurement cost	€1,451,532	€1,437,508	€767,262	€759,849
Electrical Connection costs	€7,720,000	€7,720,000	€6,930,000	€6,930,000
Water connection costs	-	-	€450,000	€450,000
Gas connection costs	-	€1,810,000	-	€3,620,000
Owners contingency	€4,525,924	€4,528,004	€4,584,060	€4,586,244
Financing costs	€1,740,740	€1,741,540	€1,763,100	€1,763,940
Interest during construction	€1,815,350	€1,841,380	€3,795,276	€3,911,362
Construction insurance	€783,333	€783,693	€793,395	€793,773
Initial fuel working capital	€4,413,073	€3,694,292	€4,413,073	€3,694,292
Other non EPC costs	€7,833,330	€7,836,930	€7,933,950	€7,937,730
Accession fees	€1,115	€1,115	€1,115	€1,115
Participation fees	€2,788	€2,788	€2,788	€2,788
Total	**€117,324,186**	**€118,474,250**	**€119,589,020**	**€122,648,093**

Table 4.16: Recurring cost estimates

Fuel Type	**NI Distillate**	**NI Dual Fuelled**	**RoI Distillate**	**RoI Dual Fuelled**
Market operator charges	€20,598	€20,747	€20,598	€20,747
Electricity transmission charges	€656,490	€661,265	€991,789	€999,002
Gas transmission charges	-	€902,920	-	€1,617,371
Operation & Maintenance	€1,791,000	€1,816,000	€1,791,000	€1,816,000
Insurance	€1,392,592	€1,393,232	€1,410,480	€1,411,152
Business rates	€631,479	€636,072	€1,507,316	€1,518,278
Fuel working capital (ongoing)[18]	€276,354	€231,343	€422,967	€354,076
Total	**€4,768,513**	**€5,661,578**	**€6,144,149**	**€7,736,626**

[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.

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.

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 and 2011 trading year. 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 and 2011 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.

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 2012. 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 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 regulatory or market evidence to change our gearing assumption of 60% for the BNE, although we note that the Competition Commission (CC) used a gearing ratio of 60% in the Bristol Water determination and NIAUR has proposed a notional gearing ratio of 55% for the WACC calculation in SONi price control consultation.[19]

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 3.0% - 4.0% in the UK.

[19] http://www.uregni.gov.uk/news/view/soni_price_control_2010_2015_consultation_paper_published

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 have noted in our 2010 and 2011 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 estimate the cost of debt for the BNE in the RoI by adjusting the risk-free rate to include an Irish CRP in the range 3.0% - 6.0%. Overall, we estimate the appropriate range for the BNE cost of debt to be 5.5% - 9.0% in the RoI. This range is broad to reflect the inherent uncertainty in the RoI economic climate and Euro-zone capital markets.

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 9.4% - 13.5% in the RoI and 6.9% - 8.5% in the UK. Our range for the cost of equity in the UK is unchanged from our 2011 BNE report. The change in the range for the RoI is driven by the rise in the risk-free rate, adjusted to include an Irish CRP of 3.0% - 6.0%.

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. WACC

Our judgement of the appropriate range for the real pre-tax WACC for the BNE peaking plant is thus 7.6% - 11.6% in the RoI and 5.5% - 7.00% in the UK.

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 5.5% – 9.0% in the RoI and 3.0% - 4.0% in the UK. The cost of debt for the UK remains unchanged from our 2011 BNE report. The range for the RoI cost of debt reflects the uncertainty in Euro-zone capital markets due to the sovereign debt crisis that continues to affect economies such as Ireland.
- Our judgement of the appropriate range for the post-tax cost of equity is unchanged in the UK at 6.9% - 8.5%. The change in the range from 2010 for the RoI is driven by the rise in the Irish risk-free rate.
- 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 rise in the ranges for the assumed real pre-tax WACC to 7.6% - 11.6% in the RoI. Our judgement of the WACC in the UK is in the range 5.5% - 7.0% in the UK.

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 revenues. This section provides the results of modelling to determine infra-marginal rents and ancillary service revenues.

6.1. Infra-marginal rent

The Plexos modelling tool has been used to determine the Infra-Marginal rent which will be earned by the BNE plant. Due to the very low running hours of the plant, the RAs modelling has identified that no infra-marginal rent would be earned by the plant.

6.2. Ancillary services revenue

There are four main types of ancillary service (AS) payments which could, in theory, be earned by the BNE plant. They are the provision of:

- Black Start capability;
- Operating Reserve;
- Replacement Reserve; and
- Reactive Power Capability.

Since the black start capability requires extra investment we have ruled it out as it is not in the spirit of costing for the "last kilowatt generator". Also since the BNE plant will conceptually be serving the last kW it will never be used for operating reserve. Similarly we would expect provision of leading/ lagging power factors to be provided more cheaply by machines already operating rather than paying the start up and shut down costs for a gas turbine. The only AS which therefore appears relevant is the provision of replacement reserve. The plant's fast start capability was one of the criteria requested for consideration by the system operator and can be provided by all the machines selected.

Table 6.1: Annual ancillary services revenues

Fuel choice	Ancillary Services Revenues
Distillate	€848,333/annum

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 1.1317 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 **€74,87/kW/yr**.
- In the RoI **€99,38/kW/yr**.

The dramatic rise in the costs of locating a BNE plant in the RoI is driven by the increase in the RoI WACC as discussed in Section 5.

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	112.91	115.18
Land and Fuel Residual Value	€ million	-1.74	-0.83
Initial Working Capital	€ million	6.66	6.87
Total Annual Costs	€ million	15.26	19.98
Plant Size	MW	192.5	192.5
Pre Tax WACC	%	6.26%	9.58%
Plant Life	Years	20	20
Deductions			
Inframarginal Rent	€ 000/annum	-	-
Ancillary Service revenues	€ 000/annum	848	848
Estimated BNE cost	€/kW	**74.87**	**99.38**

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 €74.87/kW is a reduction from the €78.73 allowed for 2011.

ANNEX 1: CEPA/PB LONG-LIST OF PLANT

2012 BNE Peaking Plant - Selection Criteria Flowchart

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

No.	2	3	4	5	7	8	9	10	12	14	15	17	18	19	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 FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800	Siemens SGT-1000F	Siemens SGT5-2000E	Siemens SGT5-3000E	Aggregated Generating Units
Nom. Power	115.4 MW	182.2 MW	75.0 MW	168.2 MW	43.0 MW	78.3 MW	127.6 MW	173.0 MW	50.8 MW	52.4 MW	103.0 MW	62.0 MW	52.7 MW	64 MW	47.0 MW	67.4 MW	169.0 MW	190.8 MW	50 MW

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	17	18	19	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 FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	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	17	18	19	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 FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	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	17	18	19	20	22	23	24	27
Option	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2		GE 6111FA*	GE 9171E		GE LM6000PC Sprint		GE LMS100	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	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	17	18	19	20	22	23	24	27
Option	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2			GE 9171E		GE LM6000PC Sprint		GE LMS100	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800		Siemens SGT5-2000E		Aggregated Generating Units

Indicators

No.	2	3	4	5	7	8	9	10	12	14	15	17	18	19	20	22	23	24	27
Option	Alstom GT11N2	Alstom GT13E2	Ansaldo# V64.3A	Ansaldo AE94.2			GE 9171E		GE LM6000PC 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		43.2	38.4		41.5	37.5		35		35
GTW equipment USD/kW	252	231	277	230			245		319		300	298		305	322		228		200
Short List*		Alstom GT13E2		Ansaldo AE94.2							GE LMS100	P&W Swift Pac					SGT5-2000E		

\# From GT PRO

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 2012. 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 and 2011, 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 consultation paper for 2011. The key points to note from the decision are as follows:

- The RAs used a real cost of debt of 4.0% for the RoI and 3.50% 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 7.95% 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 28.0% was used for the UK).

These individual parameters resulted in a real BNE pre-tax WACC of 6.04% for the RoI and 6.38% for the UK in the 2011 determination.

Table A1: WACC estimate for BNE peaking plant in 2011

	RoI	**UK**
Real RfR	2.0%	1.75%
Debt Premium	2.0%	1.75%
Real Cost of Debt	**4.0%**	3.50%
Real RfR	2.0%	1.75%
Equity Risk Premium	4.75%	4.75%
Equity beta	1.25	1.25
Post-tax Cost of equity	**7.95%**	**7.70%**
Tax rate	12.50%	28.00%
Pre-tax Cost of Equity	**9.09%**	**10.70%**
Gearing	60%	60%
Pre-tax WACC	**6.04%**	**6.38%**

Sources: NIAUR, CER

A3 Approach

The essence of our analysis remains the same as last year – we estimate the WACC parameters based on observable market data and reputable sources, and check our estimates against the relevant regulatory precedent. We do, however, take full account of newly available information and update our approach in line with that 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, including most recently the CER's decision on ESB, 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 2010 report, we noted that two UK regulators had increased their notional assumed gearing rates: Ofgem (December 2009) and Ofwat (November 2009) both raised their gearing assumptions by 2.5% compared to their previous determinations to 65% and 57.5% respectively. More recently, the Competition Commission ('CC') used an assumption of 60% gearing in the Bristol Water reference[20] while NIAUR has proposed a gearing assumption of 55% for the SONi price control consultation. 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 and 2011 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.

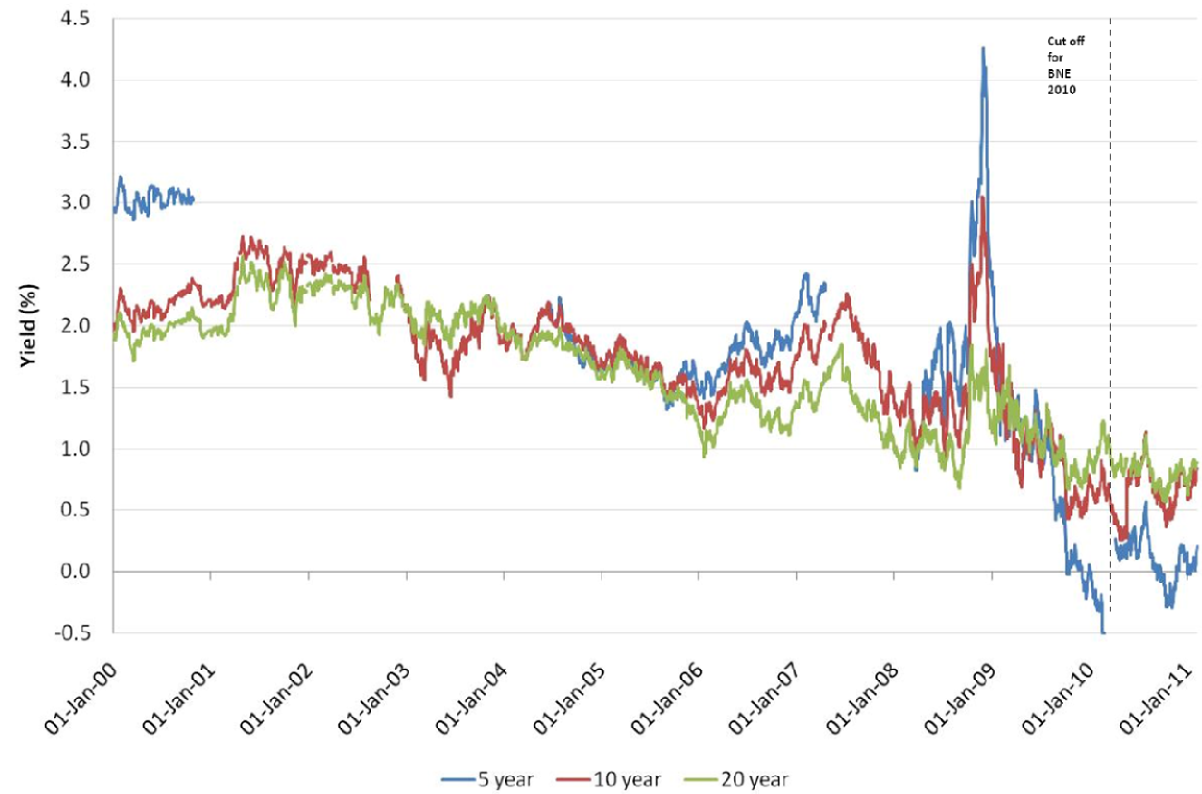
It is generally agreed that this distortion has led to lower yields being observed on long-dated ILGs than would have otherwise been the case. As a result, over-reliance on long-dated ILGs would likely result in an estimate of the real risk-free rate that was too low. Our analysis on the risk-free rate for the UK takes account of these comments.

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

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 0.65%, slightly below the 12 month trailing average of 0.7% but significantly below the 5 year trailing average of 1.3%.

Figure A1: Yields on UK index-linked gilts



Source: Bloomberg

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 not quite as clear as it is for ILGs, but it is still present. Spot rates on 10-year gilts are around 1.0% (real) lower than at the time of our report last year (when they were around 1.3%) but above the trailing average for the past 12 months (0.75%).

Figure A2: Deflated yield on UK nominal gilts

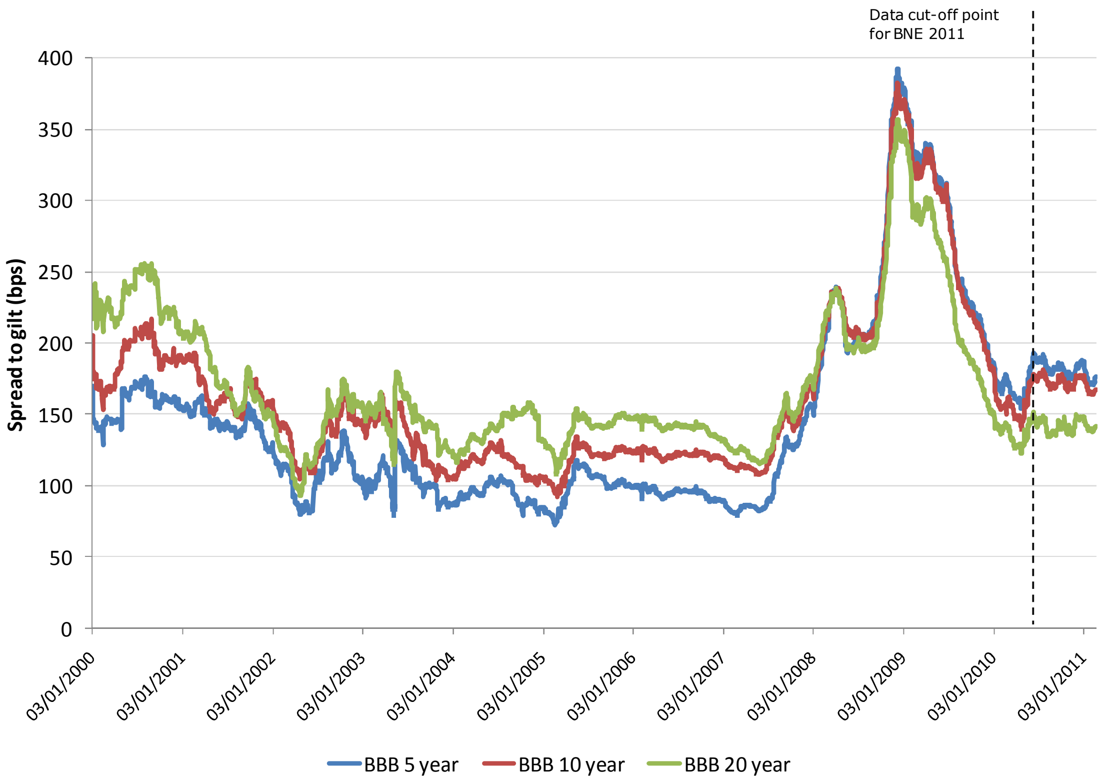
Source: Bloomberg, CEPA analysis

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 A7 shows the evolution of spreads (against 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 have narrowed gradually and have remained stable since our 2010 report. The current spot rate on 10-year debt is around 170 basis points. This is slightly above the one year average of 168 basis points.

Figure A7: 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.[21] It shows the (nominal) yield and spread at issue, as well as the current yield and spread as at 25th February 2011.

[21] 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

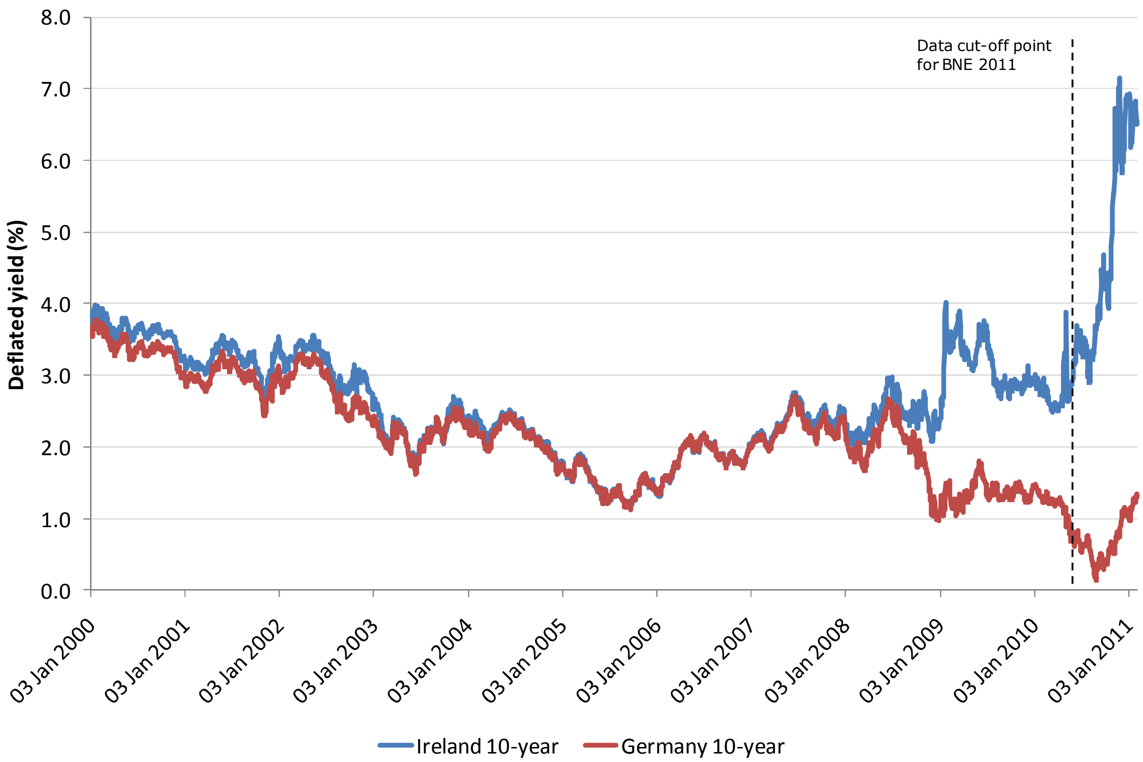
Company	Issue date	Maturity	Amount (£m)	S&P credit rating	Spread at issue (bps)	Nominal yield on 25/02/11 (%)	Spread on 25/02/11 (bps)
Anglian Water	31/01/2011	2018	350	BBB	--	6.77	357
Central Networks	10/12/2010	2025	250	A	155	5.41	135
Wales & West	31/03/2010	2030	300	A-	-	5.33	109
Northern Gas	23/03/2010	2040	200	BBB+	220	5.49	112
Wales & West	02/12/2009	2016	200	A-	245	4.13	126
EDF Energy	12/11/2009	2031	300	BBB+	175	5.66	130
EDF LPN	12/11/2009	2016	300	A	167	5.66	130
Southern Gas	02/11/2009	2018	300	BBB	155	4.52	125

Sources: Bloomberg, CEPA analysis

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 A3 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 A3 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.

Figure A3: 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 9th March 2011 on recent developments in the Europe's capital markets noted:

> "*The rise in 10-year yields for the so-called "peripheral" eurozone countries has been inexorable over the past five months. Italy has seen a jump of 1.3 percentage points, Spain 1.5 percentage points and Portugal 2 percentage points. Greece and Ireland, both of which are in multiyear EU-IMF rescue programmes, have seen rises of almost 4 percentage points.*"[22]

[22] Financial Times, 'Eurozone periphery borrowing costs soar', March 9th 2011

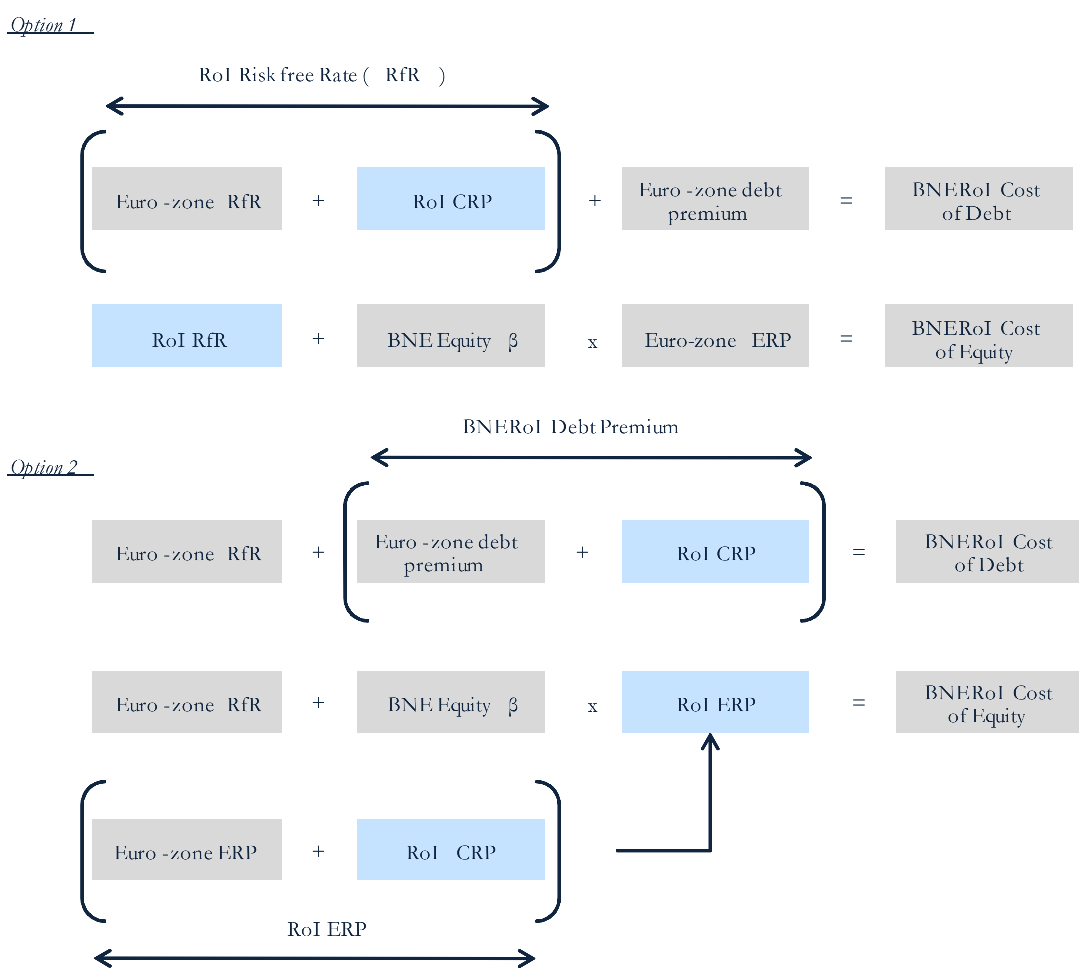
Given the ongoing debt crisis, the specific risk profile of RoI assets can be accounted for in calculating the WACC in one of two ways. The first would be to rely solely on information from Irish markets (including Irish government bonds for the risk-free rate and spreads on Irish corporate bonds for the debt premium). However, while this would represent the preferred solution, as we have noted in our 2009 and 2010 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, 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 A4: 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 A5 shows the deflated yield on Irish nominal bonds of different maturities over the past 10 years.[23] 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.

While we acknowledge that Ireland has often seen very different inflation rates to the Euro-zone average,[24] absent any long-term inflation expectations specific to Ireland[25], 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.[26]

As Figure A5 shows, the sovereign debt crisis in the RoI (and other "peripheral" Euro-zone member states) has resulted in a sharp rise in the yield on benchmark Irish government bonds. Spot rates of the deflated yield on the 10-year bond are currently around 7.1%, compared to 2.7% at the time of our 2011 BNE report.

We note the somewhat extreme increase in deflated yields on Irish nominal bonds since the last BNE data cut off point, and the impact this data has on our estimates of the WACC in RoI (the estimates are substantially higher than last year). We will review movements in this key data in the coming months – right now it is unclear to us whether and over what period these rates will normalise.

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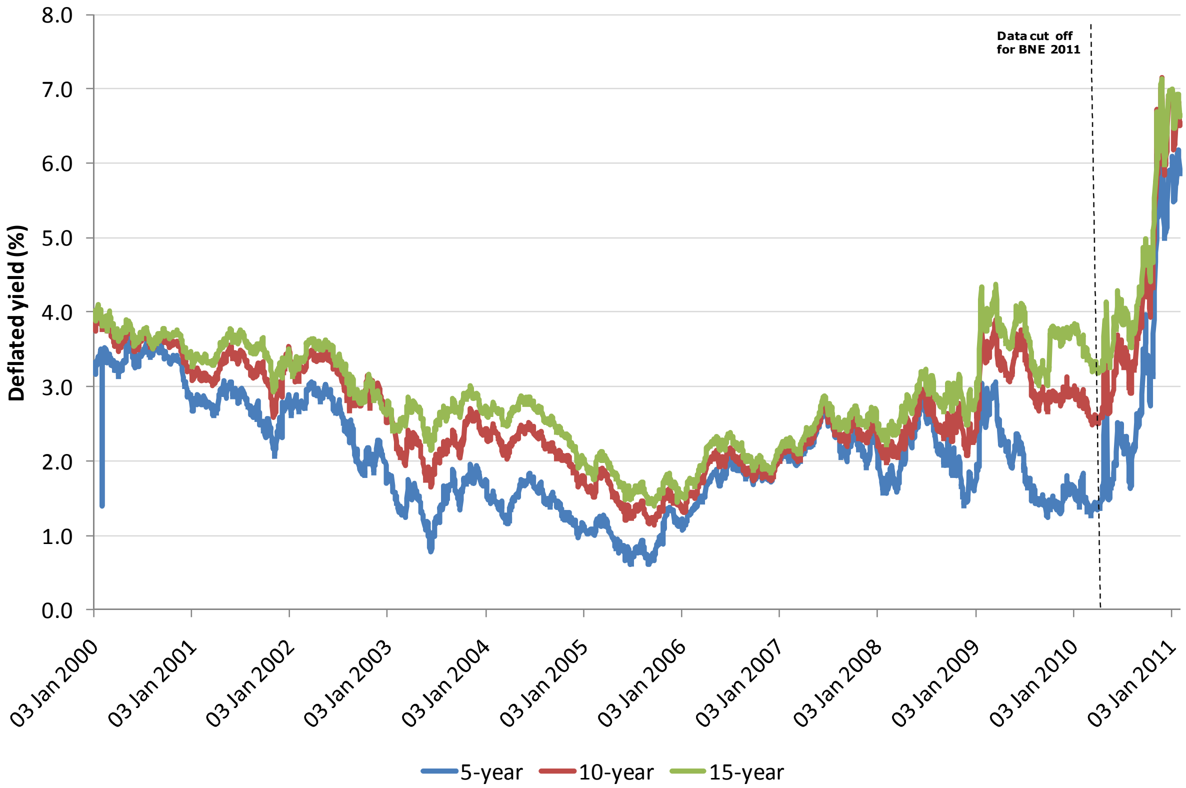
[23] Note that there is insufficient data on 20-year Irish bonds.

[24] Indeed, Irish Harmonised Index of Consumer Prices (HICP) inflation in January 2011 is estimated to be 0.2 per cent compared to 2.3 per cent across the whole of the Euro area.

[25] Shorter term forecasts for inflation in RoI, such as those provided by ESRI, are available. Note that these are below the long term deflator that we have used.

[26] 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%".

Figure A5: Deflated yield on Irish nominal bonds



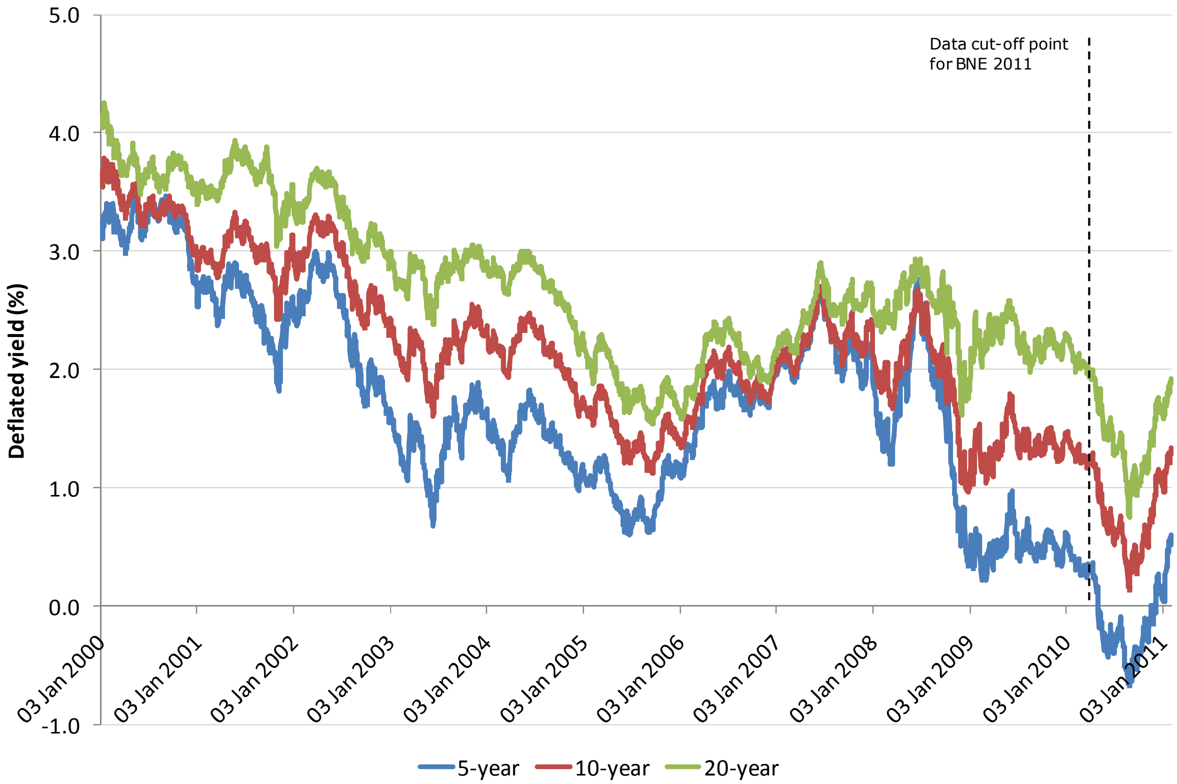
Source: Bloomberg, ECB CEPA analysis

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 A6 shows the deflated return on benchmark German sovereign bonds for the past 10 years.

Current spot rates on the 10-year benchmark bond are around 1.4%, in line with level observed around the time of our report last year. The twelve month average for the deflated yield on 10-year German government bonds is around 0.85% and within a range of 0.1% - 1.4%. 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 A6: Deflated yield on German benchmark sovereign bonds



Source: Bloomberg, ECB CEPA analysis

RoI relative to wider Euro-zone market evidence

Table A3 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 that has affected Euro-zone member states such as the RoI. The data shows that prior to the global financial crisis, the average yield on Irish and German government bonds was very similar. However, in the past 12 months, the yield differential in German and Irish sovereign debt has increased significantly, with the spread on 10-year bonds issued by the governments of the RoI and Germany above 5% at the beginning of March 2011.

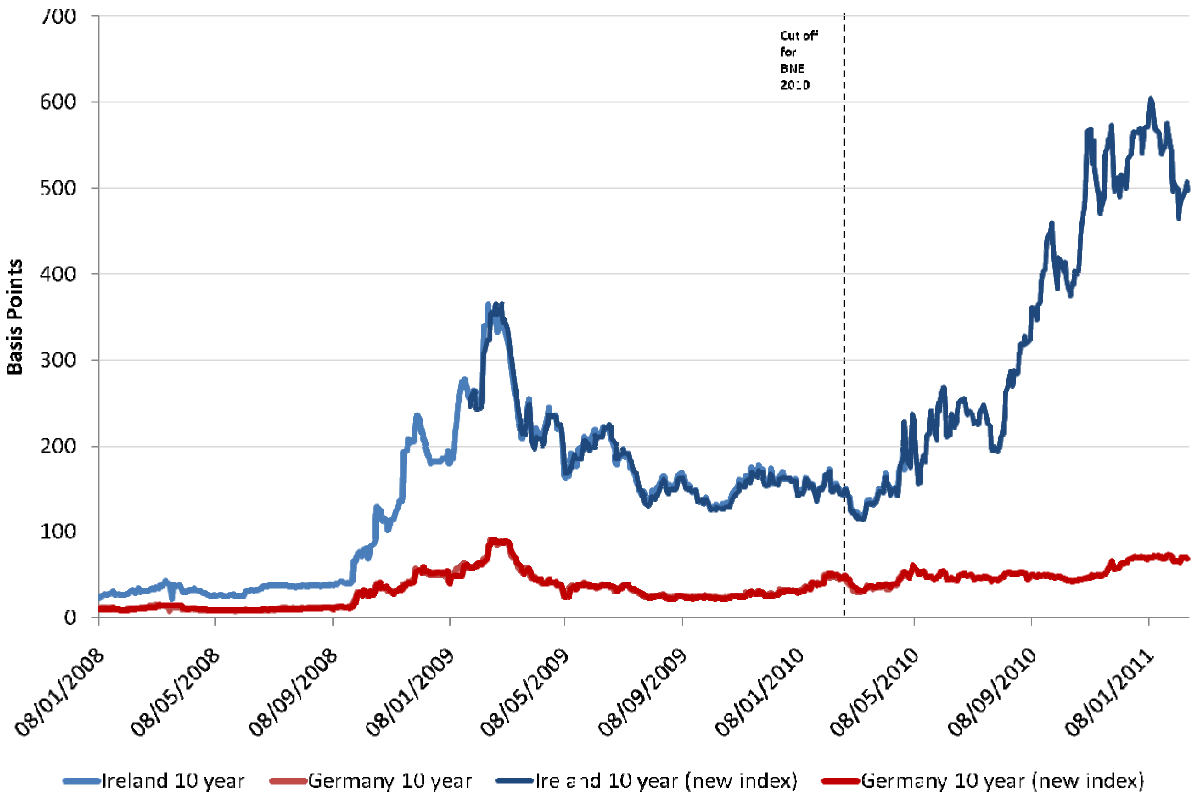
Table A3: Average yields on 10-year government bonds in Ireland and Germany

Period	RoI	Germany	Spread
Spot (3rd March 2011)	7.10%	1.39%	5.71%
1-year average	4.41%	0.84%	3.57%
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 treat of the debt defaulting.

Figure A7: 10-year Irish and German Credit Default Swaps[27]



Source: Bloomberg, CEPA analysis

Figure A7 shows that the spread on CDS for RoI and German government debt has widening significantly over the past 12 months. At the end of February 2011 the 10-year RoI CDS traded at a premium of 429 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 282 basis points.

As illustrated in Table A3, the 12 month average for yields on deflated 10 year German nominal debt is around 0.85% within a range of 0.1% - 1.4% (with current spot rates at the top of this range). A RoI CRP of 300 – 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 BNE risk free rate could lie anywhere in the range 4.0% - 7.0%. This is a very wide range for the risk-free rate, but reflects the uncertainty that continues to

[27] 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.

affect Euro-zone capital markets and specifically the borrowing costs of Euro-zone economies such as the RoI.

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 the 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. Similar to the evidence on spreads for the UK, it shows a gradual narrowing of spreads following the post-Lehman spike, although the spread has remained at unusually high levels for 20-year debt.

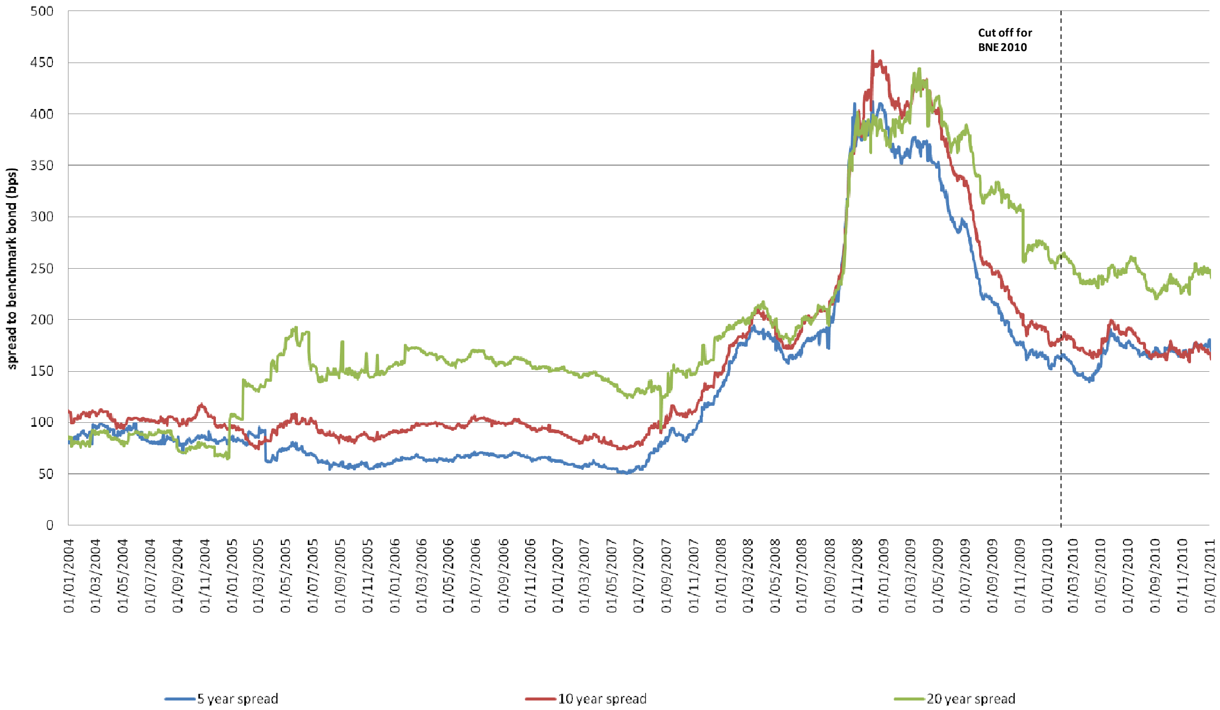
Table A4 shows information on the spot, 1-year and 5-year average for the debt premium on BBB rated Euro denominated debt.

Table A4: Spreads on BBB Euro denominated debt (basis points)

Sample	Spot (22nd Feb 2011)	1 year average	5 year average
BBB 5-year	158	167	165
BBB 10-year	149	173	188
BBB 20-year	238	242	232

Source: Bloomberg, CEPA analysis

Figure A8: Spreads on BBB rated European corporate debt



Source: Bloomberg, CEPA analysis

Table A5 contains evidence on some of the issues of euro denominated utility company debt raised in the Euro-zone during 2009, 2010 and 2011. 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 debt of maturity between five and 15 years.

Table A5: Recent Euro-zone utility debt issues

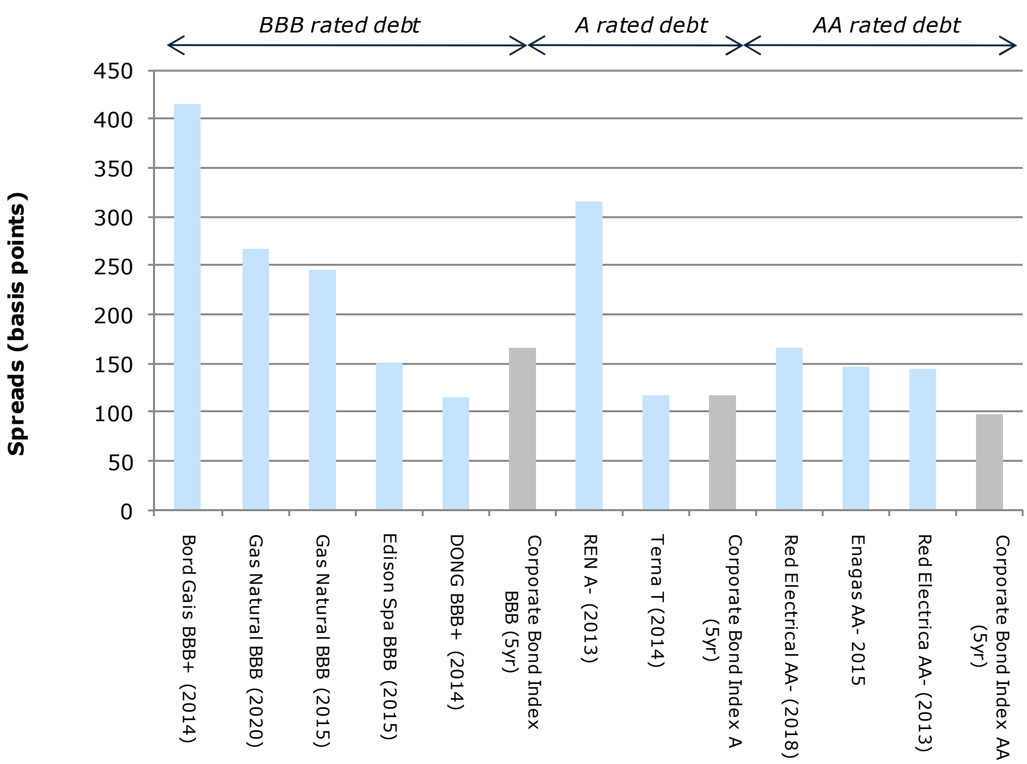
Company	Issue date	Maturity	Amount (€m)	S&P credit rating	Spread at issue (bps)	Nominal yield on 22/02/11 (%)	Spread on 22/02/11 (bps)
Tennet Hld BV	21/02/2011	2018	500	A-	101	3.77	102
Iberdrola	10/02/2011	2014	750	A-	236	3.42	168
Gas Natural	01/12/2010	2015	650	BBB+	115	4.41	247
Gas Natural	01/12/2010	2020	850	BBB+	126	5.72	257
EANDIS	30/12/2010	2020	170	n/a	-	4.25	118
Edison SpA	17/03/2010	2015	500	BBB	115	3.78	172
ENEL (Italy)	26/02/2010	2016	1000	A-	-	3.39	104
CEZ AS	28/06/2010	2020	750	A-	198	4.58	151
Iberdrola	24/02/2010	2012	25	A-	161	-	-
ENEL	24/11/2009	2020	500	A-	--	4.29	123

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 (such as Portugal) compared to generic BBB, A and AA 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

Note: Spreads are as at 22nd February 2011 and are calculated over benchmark sovereign bonds for EUR issuances

As a cross-check to the information on utility bonds in the Irish market, Table A6 shows the (nominal) yield and spread at issue, as well as the current yield and spread for BBB – A rated Irish corporate bonds in sectors other than the utility sector. The information in Table A6 also illustrates that Irish corporate debt trades at wider spreads than the cost of debt for generic Euro-zone corporate bonds with equivalent credit ratings.

Table A6: Irish corporate bond issues

Company	Issue date	Maturity	Amount (millions)	S&P credit rating	Spread at issue (bps)	Nominal yield on 22/02/11 (%)	Spread on 22/02/11 (bps)
Irish utility debt							
ESB Finance Ltd	05/03/2010	2020	£275	BBB+ /*-	250	6.98	346
Bord Gais	16/06/2009	2014	€550	BBB+ /*-	427	5.98	412
Wider market evidence							
Bank Of Ireland	03/11/2010	2013	€750	BBB+	n/a	9.18	764
Anglo Irish Bank	15/04/2010	2012	€1,500	BBB+	174	8.12	758
Irish Life & Perm	12/03/2010	2015	€50	BBB+	n/a	9.44	784

We note that in January 2011 ESB announced that it has obtained formal credit ratings from three rating agencies: Fitch, Moody's and Standard & Poor's:

"*ESB sought to obtain these ratings to enhance its access to the international debt and capital markets to support the funding of its capital expenditure programme of c. €6.5bn over the next 5 years …*

ESB is pleased to advise that the Company has been assigned a consistent investment grade credit rating (BBB+/Baa1/BBB+) from all three rating agencies "[28]

Commenting on the rating announcement, Moody's noted that:

"A*ssessment of ESB reflects (i) the low business risk profile of the Group's transmission and distribution operations … ESB's well diversified portfolio of generating assets … balanced by an established supply business with large customer bases in each of the different market segments …*

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."[29]

ESB's credit rating illustrates 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, Moody's rating announcement makes a direct link between the rating outlook for ESB and the sovereign position in the RoI.

A5.4 Regulatory precedent

In the UK and RoI there have been three regulatory determinations/consultations since we compiled our report on the cost of capital allowance for the 2011 BNE. Table A7 summarises the risk-free rate, debt premium and overall cost of debt used in each of those determinations.

[28] ESB (27 Jan 2011): 'Press release'
[29] Moody's (27 Jan 2011): 'Global Credit Research'

Table A7: Recent regulatory decisions on the cost of debt

Regulator	Decision	RfR	Debt premia	Cost of debt
United Kingdom				
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: Consultation proposal

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 2011 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%.[30] 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.

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

A5.4 Conclusions on the cost of debt

Table A8 brings together our view on the cost of debt faced by a notional BNE peaking plant in the UK. In line with the CC, our range for the UK risk free rate is 1.5% - 2.0%. Our estimate of the debt premium lies in the range 1.5% - 2.00%.

Table A8: Summary range for BNE cost of debt (UK)

Element	UK BNE 2011	UK BNE Low	UK BNE High
Risk free rate	1.75%	1.50%	2.00%
Debt premium	1.75%	1.50%	2.00%
Cost of debt	**3.50%**	**3.00%**	**4.00%**

Source: CEPA analysis

Table A9 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 3.0% - 5.0%. 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 A9: Summary range for BNE cost of debt (RoI)

Element	RoI BNE 2011	RoI BNE Low	RoI BNE High
Risk free rate	2.00%	4.00%	7.00%
Debt premium	2.00%	1.50%	2.00%
Cost of debt	**4.00%**	**5.50%**	**9.00%**

Source: CEPA analysis

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

β_{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 and 2011 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 A10 summarises their most recent analysis for the 2011 Sourcebook. CEPA considers it prudent for regulators to take account of arithmetic mean averages, which are higher.

Table A10: Dimson, Marsh and Staunton estimates of the ERP

Jurisdiction	Arithmetic mean 1900-2010	Geometric mean 1900-2010
United Kingdom	5.2%	3.9%
RoI	4.9%	2.9%
Europe	5.2%	3.9%

Source: Dimson, Marsh and Staunton

While the 2011 Credit Suisse Sourcebook shows risk premiums of 3.9% (geometric) to 5.2% (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.

In the RoI a 4.5% - 5.0% range for the ERP is consistent with our approach of arriving at a range for the BNE cost of debt where we apply a CRP to arrive at a RoI risk-free rate and then estimate the debt premium from evidence of Euro area corporate bonds yields. Rather than estimate the cost of equity of investing in the Irish economy vs the German economy, we account for the impact of the Euro-zone financial crisis by applying an adjustment to the risk-free rate and then adopting an ERP for the wider Euro-zone economy.

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 and 2011.

A.6.2. Regulatory precedent

Table A7 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 consultation paper, NIAUR uses the *total market return* (estimated as 6.75%) and an equity beta of 0.77 to derive a post-tax cost of equity of 5.64% for its price control proposals.

Table A11: Regulatory precedence on cost of equity

Regulator	Decision	Risk-free rate	ERP	Equity beta	Cost of equity
United Kingdom					
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%[31]	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

A.6.3. Conclusions on the cost of equity

Using our common ranges for UK and RoI for the ERP and equity beta and the country-specific risk-free rate estimated as part of the cost of debt analysis above, our estimated ranges for the cost of equity are presented in Table A12.

Table A12: Summary range for BNE cost of equity

	RoI Low	RoI High	UK Low	UK High
Risk-free rate	4.00%	7.00%	1.50%	2.00%
ERP	4.50%	5.00%	4.50%	5.00%
Equity beta	1.2	1.3	1.2	1.3
Cost of equity	**9.40%**	**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 2011 lies within the range 9.40% - 13.50% and for the UK in the range 6.90% - 8.50%.

[31] 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.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
- 26.0% for the UK.[32]

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 A13.

Table A13: Consortium estimate of BNE weighted average cost of capital

	RoI			UK		
	2011	**Low**	**High**	**2011**	**Low**	**High**
Risk-free rate	2.00%	4.00%	7.00%	1.75%	1.50%	2.00%
Debt premium	2.00%	1.50%	2.00%	1.75%	1.50%	2.00%
Cost of debt	**4.00%**	**5.50%**	**9.00%**	**3.50%**	**3.00%**	**4.00%**
Risk-free rate	2.00%	4.00%	7.00%	1.75%	1.50%	2.00%
ERP	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.2	1.3	1.25	1.2	1.3
Post-tax cost of equity	**7.95%**	**9.40%**	**13.50%**	**7.70%**	**6.90%**	**8.50%**
Taxation	12.50%	12.50%	12.50%	28.00%	26.00%	26.00%
Pre-tax cost of equity	**9.09%**	**10.74%**	**15.43%**	**10.70%**	**9.32%**	**11.49%**
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**6.04%**	**7.60%**	**11.57%**	**6.38%**	**5.53%**	**6.99%**

[32] Applicable from 1 April 2011.