COSTS OF A BEST NEW ENTRANT PEAKING PLANT FOR THE CALENDAR YEAR 2011

A REPORT FOR THE REGULATORY AUTHORITIES

12 May 2010

Initial Report

Submitted by:

Cambridge Economic Policy Associates Ltd in association with Parsons Brinkerhoff

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1. INTRODUCTION & CONTEXT

1.1. Overview

Cambridge Economic Policy Associates (CEPA) working with Parsons Brinkerhoff (PB) are pleased to submit this initial report on the costs of a Best New Entrant (BNE) peaking plant for the calendar year 2011 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 2011. 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 2011.

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 trading year.

This report is intended to inform the RA's consultation on the BNE price for 2011. 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 Parsons Brinkerhoff (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 Best New Entrant (BNE) plant for the 2010 trading year.

1.4. The Capacity Payment Mechanism

Objectives of the CPM

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.

Text Box 1.1 Objectives of the Capacity Payment Mechanism

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: RAs/CEPA

Structure of the CPM

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 7,356 MW for 2009 and 6,826 MW for 2010; and
- a price element which was €87.12/kW/year for 2009 and €80.74/kW/year for 2010

Previous consultations by the RAs determined that the cost of a BNE peaking plant was the appropriate basis for determining the price element of the CPM. Therefore, this cost, expressed in €/kW per annum multiplied by the available generation determines the payments under the CPM.

Medium Term Review of the CPM

CEPA and PB are aware that the RAs are currently undertaking a Medium Term Review (MTR) of the CPM. We understand the review is designed to question whether the current approach to determining the CPM is fit-for-purpose on an enduring basis given the challenges the SEM will face in future.

Issues covered by the MTR are outside the scope of this document. CEPA and PB have been appointed to determine the fixed costs 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 technology option.
- In Section 4 we consider the costs associated with the chosen 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; and
- Annex 2 provides a more detailed assessment of relevant financial issues.

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 second year for which CEPA/PB have been commissioned to determine the costs of a BNE peaking plant and recognising the largely favourable comments received from market participants regarding the methodology used in 2010, we have employed a substantively similar approach. However, we have sought to fully reflect comments received from responses and lessons learned from that process; as well as revisiting and refreshing our analysis in light of recent market developments.

2.1. The 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.

2.2. 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 2011. The high-level questions and a number of the more detailed issues they give rise to are shown in Table 2.1 below.

Table 2.1: High level questions to address.

Key question	Other issues/questions to consider
What are the characteristics of a rational investor?	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?

2.2.1. The BNE methodology

The 2011 calculation will be the fourth time that the RAs have calculated the fixed costs of a BNE plant entering the SEM. It may well also be the penultimate time this approach is used given the ongoing MTR of the CPM. 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 and a site in the Republic of Ireland and infra-marginal rent and ancillary services number deducted from that figure.
- Infra-marginal rents earned by a given plant will not be a determinant of the choice of plant (i.e. they will be calculated independently of plant selection).
- The costs of a BNE plant will be calculated for both markets and a decision as to which is best made on cost-benefit grounds.

2.3. Approach

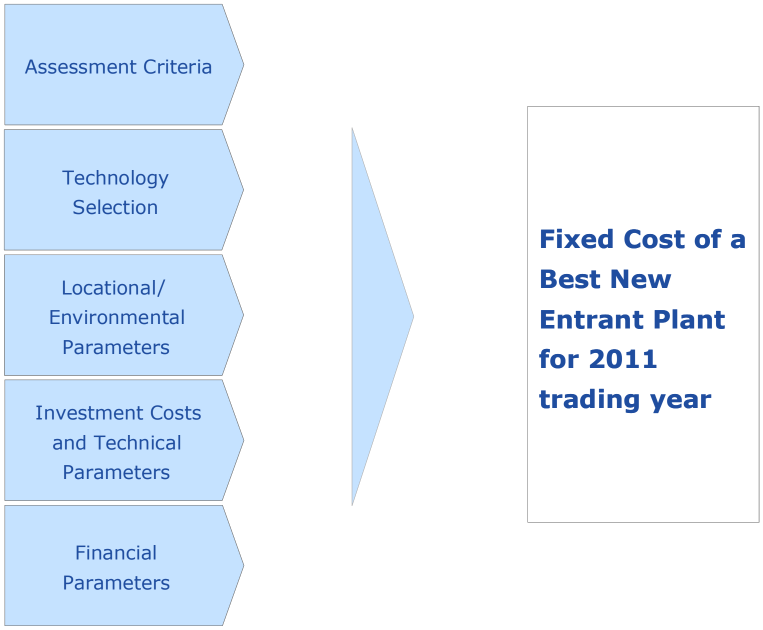
CEPA/PB are aware of the importance of the CPM to existing and prospective investors in generation and the consequences of the size of the CPM pot (the BNE price multiplied by the capacity requirement) for consumers. Our approach is consistent with that used in calculating the BNE price for the trading year 2010. We have considered the lessons from last year's approach, along with comments received from market participants.

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 2011 trading year.
- It may be located in either the Republic of Ireland or Northern Ireland and use the plant and fuel type which proves most efficient.
- The plant will serve the final MW 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.

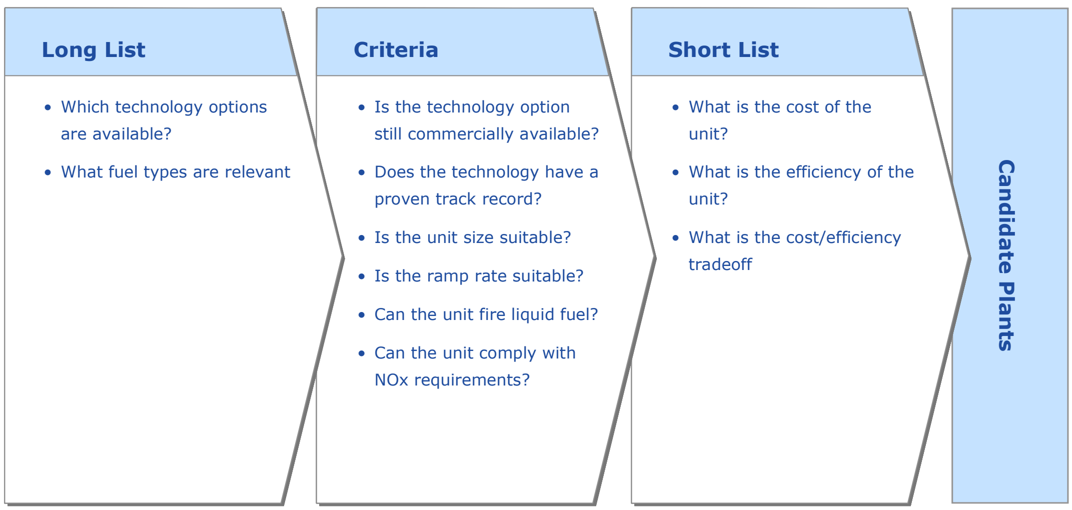
3. TECHNOLOGY SELECTION

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. This list, which is available in Annex 1, was designed to be exhaustive and cover various manufacturers and fuel-types.

3.2.1. Respondents' views to the 2010 consultation in respect of candidate peaking plants

In developing the long list for 2011, we have been mindful of comments received from respondents during the 2010 consultation process. For example, parties suggested that we should consider hydro units, second-hand plant, the interconnector as a marginal generation sources and combinations of smaller-units (Aggregated Generation Units (AGUs) in our long list.

We have carefully considered respondents' views and sought to factor them into the long-list where appropriate:

- We have held conversations with a party which aggregates AGUs to understand the capability of the generation technology as a peaker. We have also sought the views of the TSO on whether they would consider such a plant configuration to represent an appropriate peaking plant.
- Pumped storage was not considered in the 2010 calculation due to the limited number of suitable sites. However, we understand that investors are actively considering this sort of investment. We have therefore incorporated pumped storage within the long-list.
- Interconnection was excluded from the long-list due to uncertainties over whether it would always be available to serve the final MW of generation in all circumstances.

Following comments in 2010, we considered the suitability of second hand plants for the BNE. Our review concluded the following regarding the availability of second hand plant equipment:

- mainly GE machines are available;
- mainly 40MW nominal machines are available;
- larger machines for sale are typically new machines, at prices similar to that listed in Gas Turbine World; and
- mainly 60Hz machines are available.

We remain of the view that it may be difficult to source a suitable plant from the second hand market. In addition, there appear to be uncertainties associated with second hand plants. In particular, we consider that older GTs may struggle to comply with emissions requirements and consider that investors may be concerned about the potentially uncertain start-up reliability of a second hand machine.

3.2.2. 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 calculation we have considered candidate plant firing both natural gas and distillate fuel.

3.2.3. 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, particularly in respect of oxides of nitrogen (NOx), but also sulphur dioxide and dust particulates, while taking into account the expected operational profile of the plant.

The most significant issue in respect of gas turbine plant is the NOx emissions requirements. The emissions requirements which plant must be capable of meeting are shown in Table 3.1 below.

Table 3.1: Emissions limits

Fuel Type	Maximum NOx value (Mg/Nm$^{3)}$
Distillate Firing	120
Gas Firing	50

Source: Environmental Protection Agency/ Large Combustion Plant Directive

3.3. Short-listing criteria

Having developed an exhaustive long-list which covers various technology options and fuel types, we have the applied a series of short-listing criteria. These criteria are designed to reflect considerations which a rational investor may take into account in making a decision on technology as well as the requirements of the Transmission System Operators (TSOs). As in previous years, CEPA and PB (via the RAs) have sought the views of the TSOs about the appropriate assessment criteria. We would like to thank the TSOs for their useful comments.

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. However, they suggested that, while currently operating within the SEM, AGUs can be considered as a prototype technology.

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. In respect of AGUs it noted that it had undertaken performance testing of a 22MW plant which was found to have start up times and ramp rates similar to existing open cycle plant. However, SONI did not consider that an AGU should be used as the BNE peaker as the existing level of installed capacity is very low and it would be impossible to serve the entirety of SEM demand with this technology were it deemed to be the BNE plant, although CEPA's work is of course focused on investment in notional new capacity.

Having carefully considered the TSO's comments, 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 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.

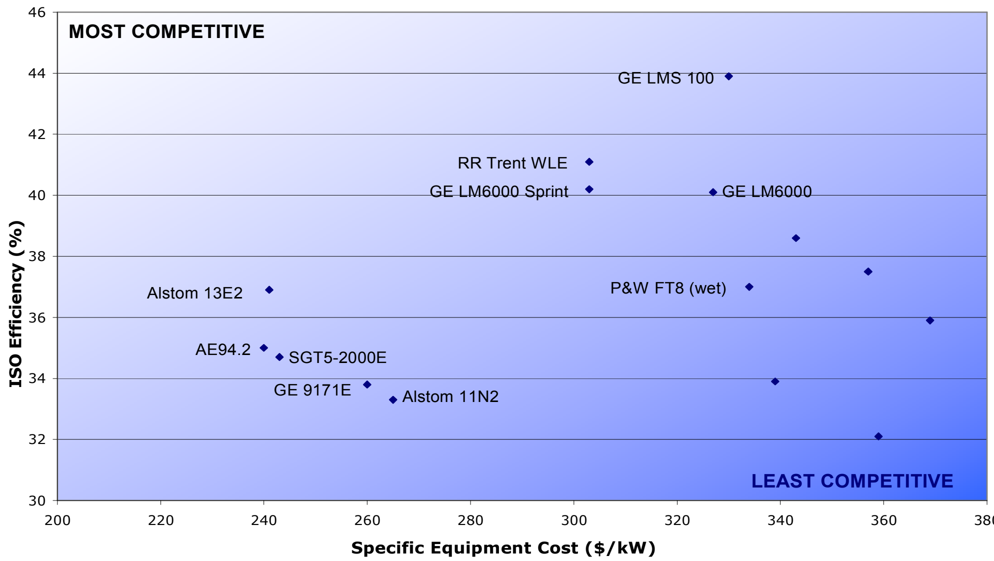
3.4. Initial filter

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 2009 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 2011 trading year.

Figure 3.2 shows the cost and efficiency trade-off for various candidate plants.

Figure 3.2: ISO Efficiency and cost trade-off for 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. It also illustrates that, given the reduced focus on efficiency, plants towards the bottom left hand corner of the diagram would be expected to be the most likely candidates to become the BNE plant.

3.4.1. Candidate plants

Having applied the filters described above and removed the plant towards the right of Figure 3.2, we identified the most practicable generating unit options for the BNE technology. In order to ensure a robust analysis, more efficient GTs such as the Rolls Royce Trent were also included such that the annualised cost at a 5% plant utilisation factor could be compared with the less expensive options. The candidate plant arrangements are as follows:

- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2
- 3 x Rolls Royce Trent WLE
- 2 x General Electric LMS100

In our analyses we have included the Alstom GT13E2, the plant selected as the BNE plant last year. We have also included the AE94.2, historically a Siemens design offered by Italian OEM Ansaldo Energia. The modified AE94.2 remains similar in design and performance to the SGT5-2000E plant investigated last year. The Rolls Royce Trent WLE was included as there is evidence that these plants have recently been chosen by investors. Similarly we have updated our assessment of the LMS100 given feedback from last year's process suggested this was being actively considered by investors in the SEM and that insurers were prepared to insure such plant.

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

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

3.5. EPC costs and plant performance

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

3.5.1. State of the EPC market

We have seen relatively little change in the EPC market relative to last year. Demand for medium to large GTs has remained strong in the Middle East, Far East and Australia and there appears to be little evidence that utilities around the world have aborted plans to implement larger GT power plants. Given the global nature of the EPC market, we have not seen a substantial fall in prices.

3.5.2. Approach to EPC Cost Estimation

As last year, our approach to EPC cost estimation includes two elements:

- Modelling the shortlisted plants in GT PRO[1].
- Adjusting 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

3.5.3. 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[2]. PB therefore uses relevant comparators to develop a series of adjustment factors which can be used to calibrate modelling results with practical experience.

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[1] GT PRO, GT MASTER and the associated PEACE programme are well established and respected GT thermal modelling and cost estimating software packages from Thermoflow Inc.

[2] We note the view of stakeholders that it is not always clear that manufacturers have the right incentives to submit accurate cost data to inform the GT Pro database and the data tends to have a time-lag within it.

During last year's calculation, we applied a 3.8% uplift to PEACE cost estimates. Having undertaken the same exercise this year (and recognising, as discussed below, that there has been a circa 5.5% increase in the unadjusted cost estimates produced by PEACE) we do not propose to apply any multiplier to PEACE costs as we feel these figures are a more accurate reflection of market conditions, as seen by PB during the course of the year, than was the case for the 2010 trading year.

3.5.4. Final EPC cost estimate and candidate plant performance

Applying the process outlined above gives final cost estimates as outlined in Table 3.3 overleaf (using Northern Ireland 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. 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.

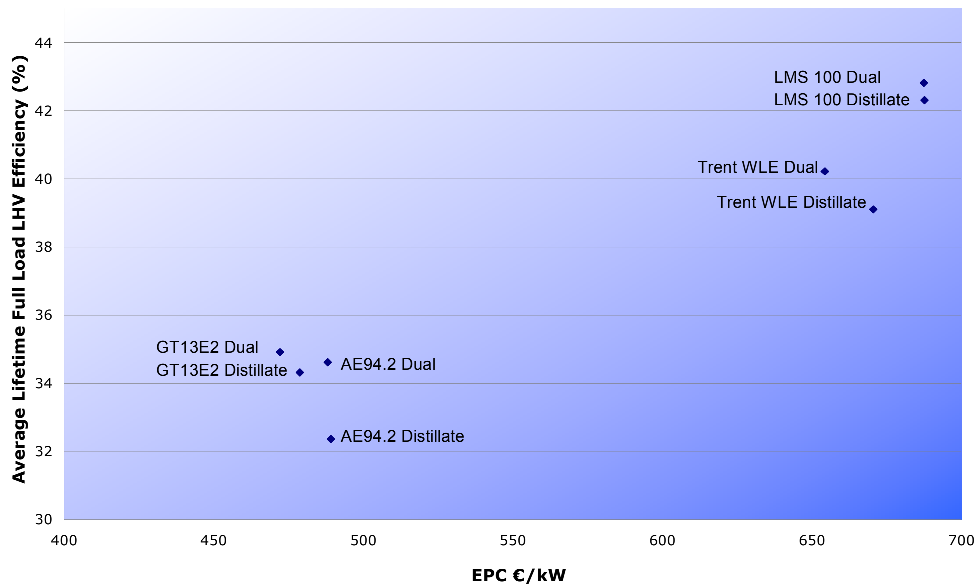
Table 3.3: Initial EPC cost assessment and power output for short-listed plants in NI.

Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)[3]
1 x Alston GT13E2	Distillate	190.1	91.0
	Gas	193.6	91.4
1 x AE94.2	Distillate	166.4	81.4
	Gas	167.7	81.9
3 x Trent WLE	Distillate	184.3	123.5
	Gas	185.6	121.5
2 x LMS 100	Distillate	195.1	134.2
	Gas	195.9	134.7

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 in the EPC cost estimates.

Figure 3.3: Efficiency and EPC cost trade-off for short-listed plant



3.6. Chosen technology option

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

Table 3.4: EPC costs €/kW

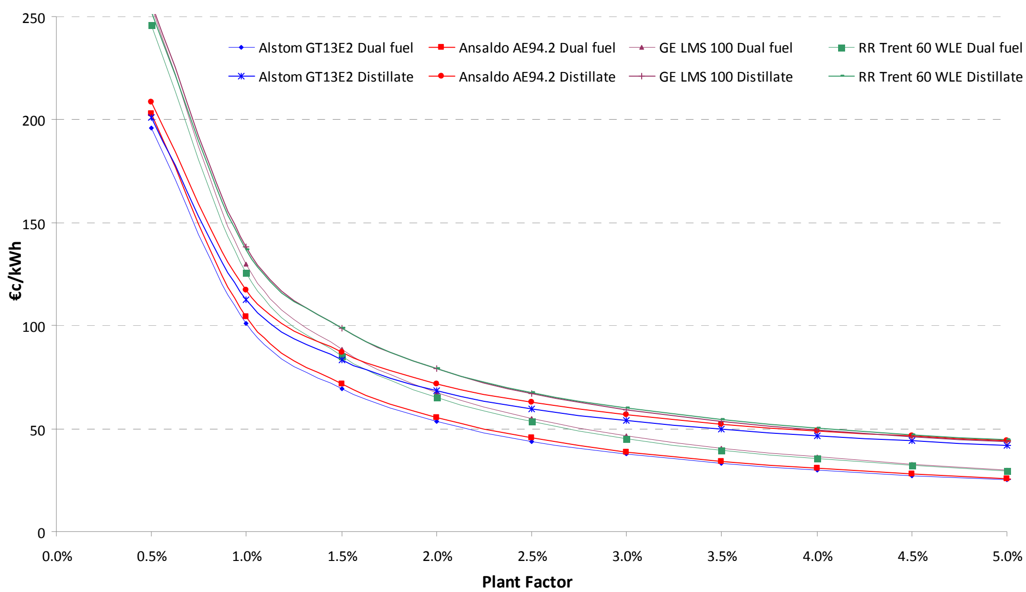
Plant Type	Fuel Type	EPC cost €/kW
1 x Alston GT13E2	Distillate	478.8
	Gas	472.2
1 x AE94.2	Distillate	489.2
	Gas	488.1
3 x Trent WLE	Distillate	670.5
	Gas	654.3
2 x LMS 100	Distillate	687.7
	Gas	687.5

While we note that based on the current market conditions the plant is unlikely to run for a significant number of hours, for completeness and in keeping with the methodology used last year we have undertaken screening-curve analysis. The results of this analysis are shown in figure 3.4.

The screening curve analysis indicates that the more efficient aeroderivative Trent WLE and LMS 100 plants are not cheaper on an annualised basis for plant factors of 5% or less. The BNE plant is unlikely to run more than around 5% of the time and in this context the aeroderivative plants do not present the cheapest BNE options.

We also note that The Alstom GT13E2 has an advantage over the Ansaldo AE94.2 plant across both fuel types and irrespective of utilisation factor.

Figure 3.4: Screening Curve Analysis (Generation cost vs plant utilisation factor)



On the basis of the approach outlined above, in CEPA/PB's opinion, it is likely that the **BNE GT for 2011 is an Alstom GT13E2**. This plant has a capacity of 190.1MW in distillate configuration and 193.6MW 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 the RoI.

3.6.1. Technical assumptions for selected option

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 Republic of Ireland.
- 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 1:1 water to fuel ratio (mass basis) at maximum plant load.
- No over-spray fogging employed.
- No Selective Catalytic Reduction for NO_x control.
- Emergency shutdown power included but 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

Box 3.1: Initial views in respect of BNE technology selection

Initial views in respect of BNE technology seclection:

- 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 last year) 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 for 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 jurisdictions. Our assessment of the property market has been informed by advice from an adviser with extensive experience in the RoI and NI property markets, including involvement in transactions involving utility companies.

There appears to be significant interest in investment in power capacity in both Northern Ireland and Ireland despite the economic downturn. Two new Combined Cycle Gas Turbines (CCGTs) are being developed at Aghada by ESB PG and at Whitegate by Bord Gáis. In addition to this there are also plans to develop a new 400MW CCGT in the Louth area, plans to repower some of the formerly divested ESB plant, and interest in new OCGT capacity[4]. We also understand that the RAs have been approached by a number of parties as the early stages of investment appraisal regarding sites in both the RoI and NI.

In considering the appropriate locations in NI and the RoI for the candidate BNE plants, we have sought to consider the factors that would influence a rational investor's choice of location. These costs will include the up-front capital costs associated with delivering the facility, ongoing operational costs and the likelihood of securing planning consents at a given site.

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, generators and the system operator, SONI, 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 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 modelling output. The outcome of this process is shown in Table 4.1 below.

Table 4.1: EPC Costs (current prices)

Location	Fuel Type	EPC Costs
NI	Distillate	€91,009,000
	Dual	€91,433,000
RoI	Distillate	€92,199,000
	Dual Fuel	€92,629,000

The reason for the difference in the NI and RoI cost estimates are 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 decision, been estimated at 18 months.

4.3.2. Site procurement costs - RoI

Relative to the time at which last year's calculation has been carried out, there has been very little transactional activity on which to base conclusions. In addition, the effects of

[4] Eirgrid Generation Adequacy Report 2009 - 2015

the banking crisis/recession have had an adverse impact on the capital value of development land in both jurisdictions and lending constraints continue to impact on the functioning of the property market.

In the RoI, CB Richard Ellis report that the reduction in value of development land is difficult to quantify but believe that in the Dublin region, it is at least 50% down from its peak a few years ago and in some provincial locations, the decline is as much as 90%. In the opinion of the National Asset Management Agency (NAMA), a Government body which has been established to manage the consequences of the financial crisis, on average, property values across all sectors have fallen 47%.

Evidence also suggests that agricultural land values in RoI have suffered a major reduction for the third year in succession and Knight Frank Ireland report that the national average price paid for farmland in 2009 dropped by 43% compared to 2008.

Given these indicators we have used a notional rate of €150k/acre for suitable greenfield land in the Republic of Ireland. This is approximately a 50% decrease compared to the value used for last year's paper. While 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).

4.3.3. Site procurement costs - NI

The Belfast Harbour Estate is owned by two landowners (Belfast City Council and Belfast Harbour Commissioners). Both these parties have a policy of not granting freeholds and 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. While it is possible that industrial land values in the Belfast area have fallen a little relative to those used last year there is no evidence available to support this conclusion since in practical terms, landowners are electing to hold on to property rather than take it to the market at the level of value quoted.

Determining an appropriate land value for the Belfast West site is further complicated by an ongoing rent review dispute which has been taken to the Lands Tribunal and has led to a refusal to settle any rent reviews since late 2008. We understand it is unlikely that this test case will be determined within the next 6 months.

We do not therefore propose to make an adjustment to the figure used in last year's consultation. Hence we use a value of £250k/acre, which is a capitalised equivalent of the £15-40k/acre rental value.

Table 4.2: Assessment of land costs

Location	Required area (m²)	Estimated site cost (€)
NI	20,600	1,443,247
RoI	20,600	763,556

4.3.4. Electrical connection costs

A significant driver of the costs of a site is the electrical connection costs the site would face. We have contacted the TSOs to understand the forecast costs for our notional sites in the RoI and NI, for which the transmission voltages are 220kV and 110kV respectively. Our cost estimates for this year are based on those received from the TSOs last year, though we have sought to confirm these values with the TSOs.

SONI suggested that costs for Belfast West would be 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 in deriving the estimate below, as this cost is included in the EPC cost estimate.

Eirgrid provided indicative electrical interconnection costs calculated in accordance with CER's approved standard transmission charges for three alternative connection designs (at both 110 and 220kv). We adjusted the 220kv estimates to include the cost of a 4km connection.

Table 4.3: Connection costs

Location	Electrical Interconnection Cost (€)
NI	7,492,999
RoI	5,676,000

4.3.5. Gas and make-up 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 used to determine 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 water connection

Location	Cost of water connection (€)	Cost of gas connection (€)
NI	0	1,690,000
RoI	420,000	3,400,000

4.3.6. Owner's 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: Owner's contingency

Location	Fuel Type	Owners contingency
NI	Distillate	€4,732,468
	Dual	€4,754.516
RoI	Distillate	€4,794,348
	Dual Fuel	€4,816.708

4.3.7. 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 shown in Table 4.6 below.

Table 4.6: Financing, interest and insurance costs

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Financing NI	1,820,180	1,828,660
Financing RoI	1,843,980	1,852,580
IDC NI	1.880,297	1,913,361
IDC RoI	2,135,956	2,205,491
Construction Insurance NI	819,081	822.897
Construction Insurance RoI	829,791	833.661

4.3.8. Fuel Working capital (initial)

It is necessary to include the costs of fuel which needs to be held to comply with various regulatory policies as a capital cost. 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[5].

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

The fuel security code for NI is currently under review, therefore 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 €3.614m for a distillate plant and €3.101m, 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$85.57/barrel[6]. It is assumed that this fuel is sold back at the end of the plant life.

Table 4.7: Initial Fuel working capital

	Total Cost for Distillate (€)	**Total Cost for Dual Fuel (€)**
Fuel working capital	3,614,384	3,101,760

4.3.9. 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	€8,190,810
NI	Dual	€8,228,970
RoI	Distillate	€8,297,910
RoI	Dual Fuel	€8,336,610

4.3.10. Market accession and participation fees

Parties will also need to pay market accession and participation fees before beginning operating. These have been reduced compared to the previous year costs are shown in the table below.[7]

http://www.cer.ie/GetAttachment.aspx?id=7946b756-ce83-471a-b8fa-04d91610af88

[6] Oil price used was ICE Brent Crude as traded on 14 April 2010 (source Bloomberg)

[7] http://www.niaur.gov.uk/uploads/publications/Decision_Paper_SEMO_Price_Control.pdf

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	€2,800	€2,800

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 & 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[8].

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

Table 4.9 provides our initial estimates of the market operator tariffs which apply to the BNE peaking plant. In the subsections which follow, we consider the TUoS and loss factors which apply to the BNE in more detail.

Table 4.10: Relevant network charges

Type of charge	Charge amount	Total Cost
Fixed market operator tariffs for Generator units	€87.8/MW	Distillate - €16,690 Dual - €16,998

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 2010 and we use the most recent tariffs as the best estimate of the tariffs which the BNE plant will face.

[8] For more information see http://www.niaur.gov.uk/uploads/publications/SEMO_Revenues_and_Tariffs_Decision030908.pdf.

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 January 2010[9]. For the period 1 February 2010 to 30 September 2010, the charge is £290.07/MW per month. We propose to use this figure, converted at a €/£ exchange rate of 1.1341, 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[10]. For conventional generation, Generation Network Location-Based Capacity Charges vary between €0.18/kW/annum and €10.02/kW/annum[11]. 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 €5.06/kW/annum, representing a midpoint of this range.

Our estimates of electricity transmission capacity charges are summarised in Table 4.10 below.

Table 4.11: TUoS charges

Location	Fuel Type	TUoS charge (€)
NI	Distillate	750,443
	Dual Fuel	764,259
RoI	Distillate	961,906
	Dual Fuel	979,616

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[12].

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[9] http://www.soni.ltd.uk/upload/TUoS%20CHARGING%20STATEMENT%20_FInal__290110.pdf

[10] More information is available from http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx#TariffDocuments

[11] See http://www.eirgrid.com/media/2009-2010%20Statement%20of%20Charges%20v1%201%20-%2001%2002%202010%20(CER%20APPROVED).pdf

[12] We note that 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

Table 4.12: Gas transmission charges

Jurisdiction	Cost per kWh of peak day capacity	Plant Size (MW)	Efficiency (%)	Assumed hours run	Transmission Charge
NI capacity	£0.3157/kWh	193.6	34.91	4 hours per peak day	876,388
RoI transmission interconnection	€0.432614/kWh €0.221618/kWh	193.6	34.91	4 hours per peak day	1,607,162

4.4.3. Operation and maintenance costs

Similar to last year 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. For the distillate option, this amounts 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 cost estimate
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. We have assumed insurance costs are 1.6% of EPC costs.

Table 4.14: Insurance costs

	NI (€)	RoI (€)
Distillate	1,456,144	1,475,184
Dual Fuel	1,462.928	1,482.064

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 Northern Ireland also regional basis). We have used the same approach to determining business rates as used in previous years. For Northern Ireland 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. For the Republic of Ireland 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 4.15: Annual business rates

	NI (€)	RoI (€)
Distillate	606,622	1,488,523
Dual Fuel	926,686	1,515,929

4.5. Summary[13]

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

Table 4.16: Investment Cost estimates (€)

Cost Item	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
EPC Costs	92,629,000	92,199,000	91,433,000	91,009,000
Site Procurement	763,556	763,556	1,443,247	1,443,247
Electrical connection Costs	5,676,000	5,676,000	7,492,999	7,492,999
Gas connection	3,400,000	-	1,690,000	-
Water connection	420,000	420,000	-	-
Owners Contingency	4,816,708	4,794,348	4,754,516	4,732,468
Financing Costs	1,852,580	1,183,980	1,828,660	1,820,180
Interest During Construction	2,205,491	2,135,956	1,913,361	1.880,297
Construction Insurance	833,661	829,791	822,897	819,081
Other non EPC Costs	8,336,6110	8,297,910	8,228,970	8,190,810
Accession & Participation Fees	3,915	3,915	3,915	3,915
Total	**120,937,449**	**116,964,384**	**119,611,578**	**117,391,935**

[13] We note that the numbers summarised in table 4.16 and 4.17 are reported in unrounded form in order to ensure that the numbers sum up accurately within the tables. Please note that in some cases the numbers reported are approximations

Table 4.17: Recurring cost estimates (€)

Cost Item	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
Market operator charges	16,998	16,691	16,998	16,691
Electricity Transmission Charges	979,616	961,906	764,259	750,443
Gas Transmission Charges	1,607,162	0	876,388	0
Operation and maintenance costs	1,816,000	1,791,000	1,816,000	1,791,000
Insurance	1,482.064	1,475,184	1,462.928	1,456,144
Business Rates	1,515,929	1,488,523	926,686	606,622
Fuel working capital (ongoing)[14]	187,222	218,164	197,768	230,453
Total	**7,604,991**	**5,951,468**	**6,016,103**	**4,851,352**

4.6. Initial view

On the basis of these figures (noting that some need to be updated) the distillate option is clearly cheaper that the dual fuelled options irrespective of location.

Text Box 4.1: Initial views regarding BNE cost estimates

Initial view:

- On the basis of cost, the BNE plant is highly likely to be distillate fired.

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

5. ECONOMIC AND FINANCIAL PARAMETERS

This section outlines our consideration of the economic and financial parameters applying to the BNE plant. It follows the format and approach CEPA used in respect of the BNE calculation for the 2010 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 last year's 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. The RA's also face significant challenges in setting the cost of capital for the BNE given the continued uncertainty as to the direction and volatility of financial markets post-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 2011. 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 methodology for assessing the cost of capital for a BNE peaking plant makes the following key assumptions in this regard, which are unchanged from our assumptions last year:

- **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** - 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. We also assume that the investor would seek to maximise the debt/equity ratio, but that 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[15]. In our analysis of market data, we have employed data for BBB grade debt, which is a more conservative assumption.

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 in the SEM.

5.2. Estimate of BNE cost of capital

5.2.1. Gearing

Identifying an appropriate gearing assumption for the BNE is inevitably a judgment. We have seen no compelling evidence to change our assumption of 60%, although we note that two UK regulators have increased their notional assumed gearing rates: Ofgem (December 2009) and Ofwat (November 2009) both raise their gearing assumptions by 2.5% compared to their previous determinations to 65% and 57.5% respectively.

5.2.2. Cost of debt

In assessing the risk-free rate, we have looked at evidence from the markets for nominal and index linked gilts from the UK, RoI and Europe. We have also considered evidence from the credit default swap markets for RoI and Germany.

For the debt premium we have looked at spreads over benchmark gilts, as well as costs for recent issues by investment grade utilities in the UK and RoI.

Our approach of considering the cost of debt through the capital markets is consistent with established practice. We have not sought to consider the cost of debt through an examination of potential bank provided finance for a number of reasons. Firstly, there is typically a lack of transparency around the potential costs of any bank finance; secondly,

[15] Using Standard and Poors nomenclature

even if we were to try to assess these costs, a key aspect would be to assess the cost of finance for banks themselves, and that is best evidenced through the bond markets and credit default swaps; and thirdly, our discussions with banks have confirmed that bond finance is a more likely route for a notional investor.

The analysis shows a marginal increase (of 25bps) in the prudent top end of the range for the risk-free rate for RoI to 2.5%, but more significantly a dramatic decrease in the debt premium for both the RoI and UK (by about 150 and 125bps respectively). This significantly lowers our assumed cost of debt.

On the basis of the evidence presented in Annex 2, our estimate of the appropriate range for the BNE cost of debt is 3.0% – 5.0% in the RoI and 3.0% - 4.0% in the UK.

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 little changed at 6.9% - 9.0% in the RoI and 6.9% - 8.5% in the UK. The slight change in the top end of the range for the RoI is driven by the increased top end for the risk-free rate.

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 4.95% - 7.1% in the RoI and 5.6% - 7.1% in the UK.

Text box 5.1: Initial views in respect of BNE economic and financial parameters

Initial views.

- On the basis of market evidence and new regulatory precedent, we believe that a reasonable estimate for the gearing of the BNE continues to be 60%.
- We continue to assume that the plant life for the BNE will be 20 years and that the BNE investor would target an average debt life of 10 years. We also continue to conservatively assume that whilst the investor will be 'investment grade', the debt raised will be based on BBB grade costs.
- Our estimate of the appropriate range for the BNE cost of debt is 3.0% – 5.0% in the RoI and 3.0% - 4.0% in the UK, a significant reduction from last year driven by falling corporate debt premia.
- Our judgement of the appropriate range for the post-tax cost of equity is essentially unchanged at 6.9% - 9.0% in the RoI and 6.9% - 8.5% in the UK, which is in line with new regulatory precedent.
- 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 reduction in the ranges for the assumed real pre-tax WACC to 4.95% - 7.1% in the RoI and 5.6% - 7.1% in the UK.

6. INFRA-MARGINAL RENT & 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 revenues

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.

We note that the harmonised rates have not been revised since the BNE calculation for 2010. We have used the same rates as last year from the Statement of Payments and Charges for Ancillary Services Providers 2010, the AS revenue was calculated and is shown in Table 6.1.

Table 6.1: Annual ancillary services revenues

Fuel Choice	Ancillary Services Revenues
Distillate	€920,339/annum

7. INITIAL VIEW OF THE BEST NEW ENTRANT 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 1.1341 Euros to the pound[16].	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 best new entrant plant in either the RoI or at Belfast West in NI.

On the basis of the evidence set out, the costs would be:

- At Belfast West **€78,13/kW/yr.**
- In the RoI **€82,31/kW/yr.**

[16] The exchange rate used for the assessment is £1=€1.1341 (www.oanda.com 14 April 2010)

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

Line Item	Unit	RoI	NI
Total investment costs	€ million	116.964	117.392
Land and Fuel Residual Value	€ million	-1.356	-1.469
Initial Working Capital	€ million	5.799	5.613
Total Annual Costs	€ million	5,951	4,851
Plant Size	MW	190.1	190.1
Pre Tax Weighted Average Cost of Capital	%	6.04	6.38
Plant Life	Years	20	20
Deductions			
Inframarginal Rent	€ 000/annum	0	0
Ancillary Service revenues	€ 000/annum	920	920
Estimated BNE cost	**€/kW**	**82.31**	**78.13**

- 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 €78.13/kW is a reduction from the €80.74 allowed for 2010.**

ANNEX 1: CEPA/PB LONG-LIST OF PLANT

2011 BNE Peaking Plant - Selection Criteria Flowchart

Initital Considerations of 50 Hz Technology Options between 40MW and 200MW

No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo AE64.3A	Ansaldo AE94.2	GE 6581B	GE 6591C	GE 6111FA	GE 9171E	GE 9231EC	GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	GE LM6000PG Sprint	GE LMS100 PA	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800	Siemens SGT-900	Siemens SGT-1000F	Siemens SGT5-2000E (33 MAC)	Siemens SGT5-3000E (41 MAC)	Siemens SGT5-3000E (33 MAC)	Pumped Storage	Aggregated Generating Units
Type	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	PS	AGU
ISO output per machine	56.5 MW	113.6 MW	180.2 MW	75.0 MW	168.2 MW	42.1 MW	43.0 MW	78.3 MW	127.6 MW	173.0 MW	43.5 MW	47.2 MW	50.5 MW	52.4 MW	98.5 MW	50.3 MW	55.4 MW	52.7 MW	64 MW	47.0 MW	49.5 MW	67.4 MW	167.7 MW	190.8 MW	207.7 MW	100-200 MW	50 MW

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

No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2	GE 6581B	GE 6591C	GE 6111FA	GE 9171E	GE 9231EC	GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	GE LM6000PG Sprint	GE LMS100	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800	Siemens SGT-900	Siemens SGT-1000F	Siemens SGT5-2000E (33 MAC)	Siemens SGT5-3000E (41 MAC)	Siemens SGT5-3000E (33 MAC)	Pumped Storage	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.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2	GE 6581B		GE 6111FA	GE 9171E		GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	GE LM6000PG Sprint	GE LMS100	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800			Siemens SGT5-2000E (33 MAC)			Pumped Storage	Aggregated Generating Units

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

No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2	GE 6581B		GE 6111FA*	GE 9171E		GE LM6000PC	GE LM6000PC Sprint			GE LMS100	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800			Siemens SGT5-2000E (33 MAC)			Pumped Storage	Aggregated Generating Units

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

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

No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	Ansaldo AE94.2	GE 6581B			GE 9171E		GE LM6000PC	GE LM6000PC Sprint			GE LMS100	P&W FT8 Swift Pac 60 (dry)^	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry	RR Trent 60 WLE	Siemens SGT-800			Siemens SGT5-2000E (33 MAC)			Pumped Storage	Aggregated Generating Units

^ The UK Sales Manager was doubtful of the DLN Swift pac's ability to fire distillate.

Indicators

No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo# V64.3A	Ansaldo AE94.2	GE 6581B			GE 9171E		GE LM6000PC	GE LM6000PC Sprint			GE LMS100	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)		RR Trent 60 WLE	Siemens SGT-800			Siemens SGT5-2000E (33 MAC)			Pumped Storage	Aggregated Generating Units
ISO efficiency	33.9	33.3	36.9	35.9	35.0	32.1			33.8		40.1	40.2			43.9	38.6	37		41.1	37.5			34.7			n/a	35
GTW equipment USD/kW	339	265	241	369	240	359			260		327	303			330	343	334		303	357			243			1405	227
Short List*			Alstom GT13E2		Ansaldo AE94.2										GE LMS100				RR Trent 60 WLE								

\# From GT PRO

ANNEX 2: COST OF CAPITAL FOR A BEST NEW ENTRANT PLANT

A1.1 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 2011. 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 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.

Compared to the BNE 2010 determination, the main difference in this year's WACC estimates is a significant reduction in the debt premia in both the RoI and UK. This corresponds to observed trends in corporate debt spreads, which have narrowed significantly since CEPA carried out the analysis for the BNE 2010 WACC.

A.2. Summary of previous year determination

In the cost of capital determination for 2010, 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. These parameters were left unchanged in the final decision by the RAs. The key points to note from the decision are as follows:

- The RAs used a real cost of debt of 5.38% for the RoI and 4.75% for the UK. This was derived on the basis of an international utility with a credit rating of BBB operating the BNE and was based on government and corporate bond market data from Europe and the UK.
- The real post-tax cost of equity for a BNE plant was estimated as 7.81% for the RoI and 7.69% 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 pre-tax WACC of 6.80% for the Republic of Ireland and 7.13% for the UK.

Table A1: WACC estimate for BNE peaking plant in 2010

	RoI	UK
Real RfR	1.88%	1.75%
Debt Premium	3.5%	3.0%
Real Cost of Debt	**5.38%**	**4.75%**
Real RfR	1.88%	1.75%
Equity Risk Premium	4.75%	4.75%
Equity beta	1.25	1.25
Post-tax Cost of equity	**7.81%**	**7.69%**
Tax rate	12.5%	28%
Pre-tax Cost of Equity	**8.93%**	**10.68%**
Gearing	60%	60%
Pre-tax WACC	**6.80%**	**7.13%**

Sources: NIAUR, CER

A.3. 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 since there is limited precedent of regulators setting a WACC for a generator subject to competitive and market constraints. The RAs also face significant challenges in setting the cost of capital for the BNE given the continued uncertainty about the timing and direction of financial markets post-crisis.

A.4. 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.

We note that in recent regulatory decision both Ofgem (December 2009) and Ofwat (November 2009) increased their gearing assumption by 2.5 percentage points compared to their previous determinations to 65% and 57.5% respectively. In contrast, regulators' decisions on airports (which are seen as more risky than network utilities) were based on a notional gearing assumption of 50%.

Overall, we do not consider that information since our last report presents a compelling case to change our assumption and thus continue to recommend using a gearing assumption of **60%**.

A.5. Cost of debt

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

A.5.1. 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 2009 report. 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.

A.5.2. Market evidence on cost of debt components

In this section we consider the evidence on the risk free rate (looking at both indexed-linked and nominal gilts) and the debt premium.

A.5.2.1.Risk-free rate (United Kingdom)

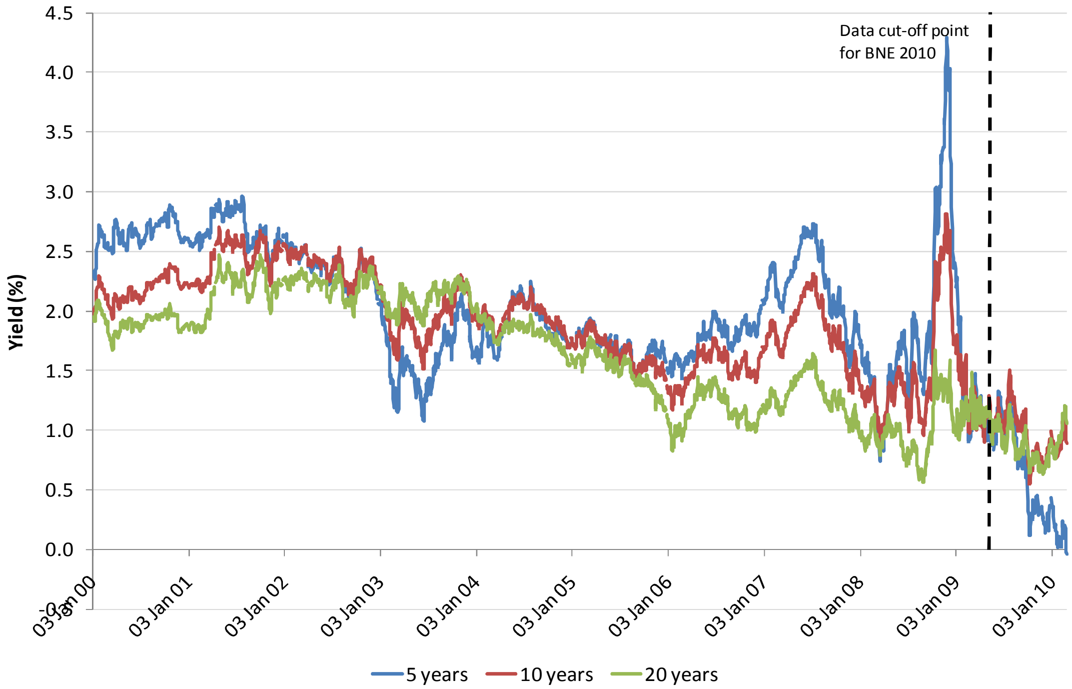
Index-linked debt

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.

Figure A2 shows movements in the yields on benchmark ILGs over the past 10 years. It shows that the yields on ILGs have recently been slightly below pre-crisis levels. In recent months the yield curve has steepened, but while we note that the 10-year and 20-year ILGs have been gradually rising lately, it is the sharp decline in the 5-year ILGs that has been the main cause of the yield curve steepening. We suspect that the Bank of England's quantitative easing policy is responsible for the sharp decline in the yields on short-dated ILGs and any regulatory decision that relies on ILGs needs to consider the possibility that this trend will be reversed during the control period.

Figure A2: Yields on UK index-linked gilts



Source: Bank of England

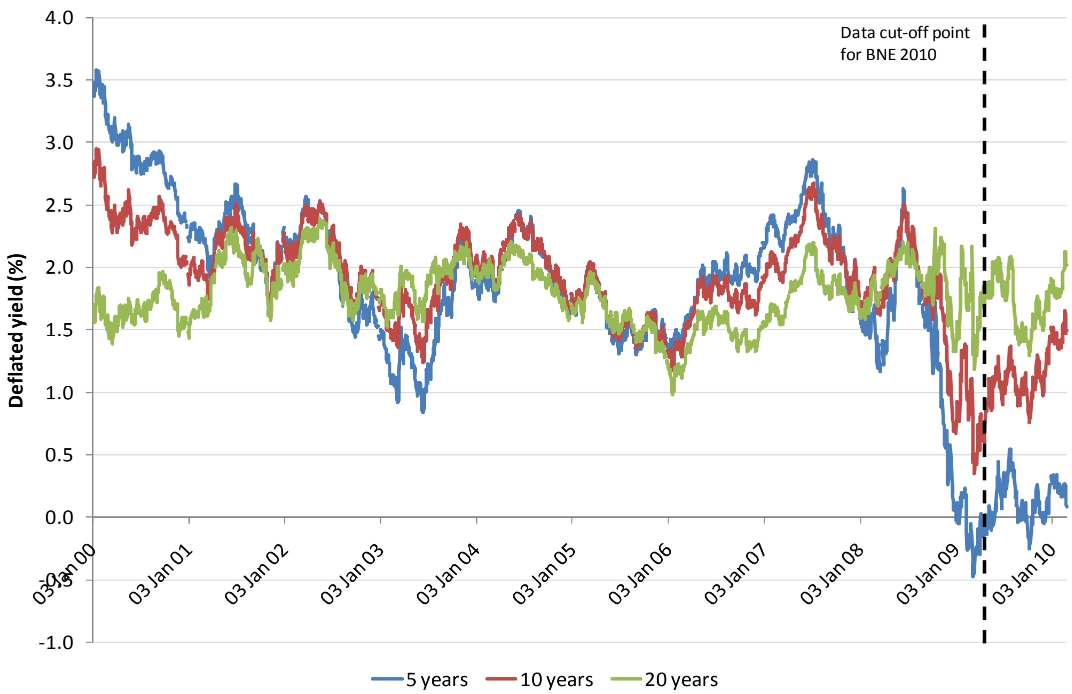
Spot rates on 10 year ILGs are currently around 1.0%, similar to where they were at the time of our report last year and in line with their average over the past 12 months.

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%.

Figure A3 shows the movements in the deflated yield on nominal gilts over the past 10 years. Here the historical downward trend is not as clear as it is for ILGs, although this may suggest that inflation expectations were not as well anchored at the start of the decade as they are now.

Figure A3: Deflated yield on UK nominal gilts



Source: Bank of England, CEPA analysis

Spot rates on 10-year gilts are around 1.5% (real), indicating the extent to which ILG yields might be depressed as a result of inelastic institutional demand. We note that current spot rates are higher than at the time of our report last year (when they were around 1.1%) and also above the average for the past 12 months (also 1.1%).

A.5.2.2. Risk-free rate (RoI)

In the absence of Irish government issued ILGs, our methodology for estimating the real risk-free rate for the RoI can be characterised as follows:

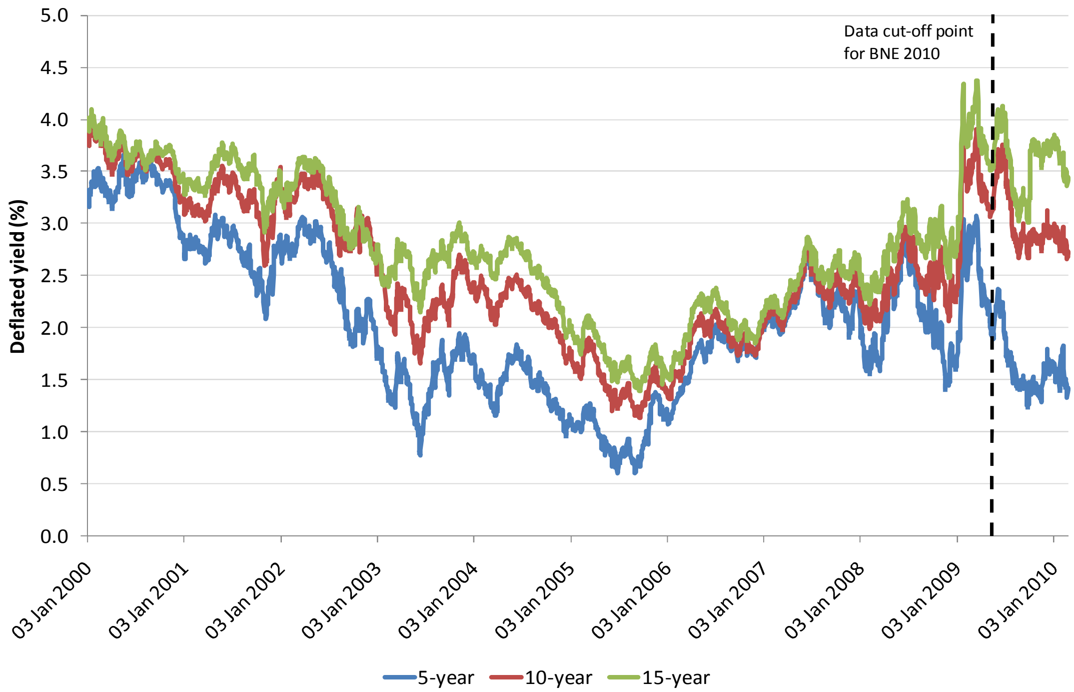
- estimate the risk-free rate derived from deflating Irish nominal bonds; and
- sense-check this against:
    - a nominal risk-free rate for German Bundesbank issued euro denominated debt (the Bund being the most liquid European sovereign debt market) and deflate this for inflation expectations to determine a real rate for euro denominated debt;
    - evidence for euro denominated debt from euro denominated index-linked bond markets;evidence on the differences in Irish and German rates.

It is necessary to cross-check the RoI data with Eurozone data as the RoI government bond market is more shallow than the Eurozone market, and hence can show significant short to medium term distortions relative to the larger Eurozone markets. Over the longer term, it may be that the Eurozone data is a good indicator of the RfR for a particular Eurozone economy, but in the short to medium term it is important to review country-specific data as we are interested in the risk-free rate for investment into RoI specifically, and investors do not necessarily view the Irish debt market as equivalent to the benchmark Eurozone debt market.

Conventional Irish sovereign debt

Figure A4 shows the deflated yield on Irish nominal bonds of different maturities over the past 10 years.[17] While we acknowledge that Ireland has often seen different inflation rates to the Euro-zone average, absent any long-term inflation expectations specific to Ireland, we consider that the best approach is to deflate by estimates from the ECB Survey of Professional Forecasters.

Figure A4: Deflated yield on Irish nominal bonds



Sources: Bloomberg, ECB, CEPA analysis

Yields spiked in late 2008 / early 2009 but have since been gradually declining. Spot rates of the deflated yield on the 10-year bond are currently around 2.7%, compared to a 3.1% average for the last 12 months.

Nominal Euro-zone sovereign bonds

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, which we then deflate by long-term inflation expectations taken from the European Central Bank's (ECB) Survey of Professional Forecasters.[18]

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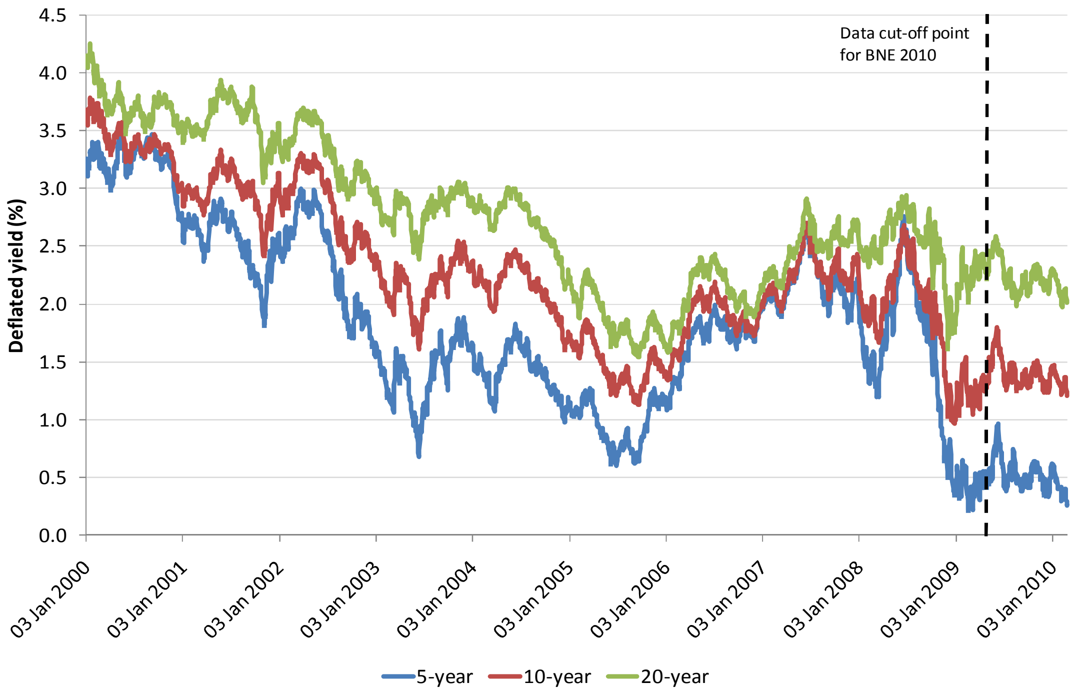
[17] Note that there is insufficient data on 20-year Irish bonds.

[18] 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 shows the deflated return on benchmark German sovereign bonds for the past 10 years. The German yield curve steepened sharply in late-2008 and has remained so ever since.

Figure A5: Deflated yield on German benchmark sovereign bonds



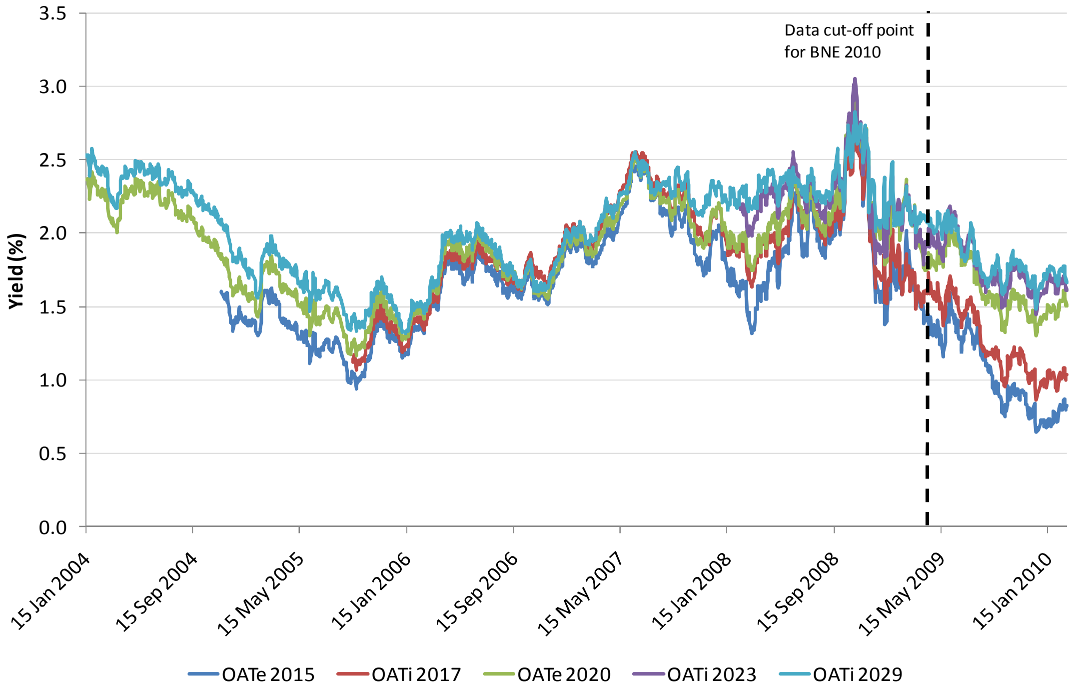
Source: Bloomberg, ECB, CEPA analysis

Current spot rates on the 10-year benchmark bond are around 1.2%, in line with the level observed around the time of our report last year but below the average for the past 12 months (1.4%).

Euro-zone index-linked bonds

France is the main source of Government-backed index-linked bonds in the Euro-zone. Figure A6 shows the yields on a selection of French Government index-linked bonds (OATis). It illustrates that the movements in yields for French Government index-linked bonds mirror those of the deflated nominal Euro-zone benchmark bonds. In particular, we note that the yield curve was very flat between 2006 and 2009 but has steepened since the start of 2009, mainly due to fall in the yield on short-dated bonds.

Figure A6: Yields on French Government index-linked bonds



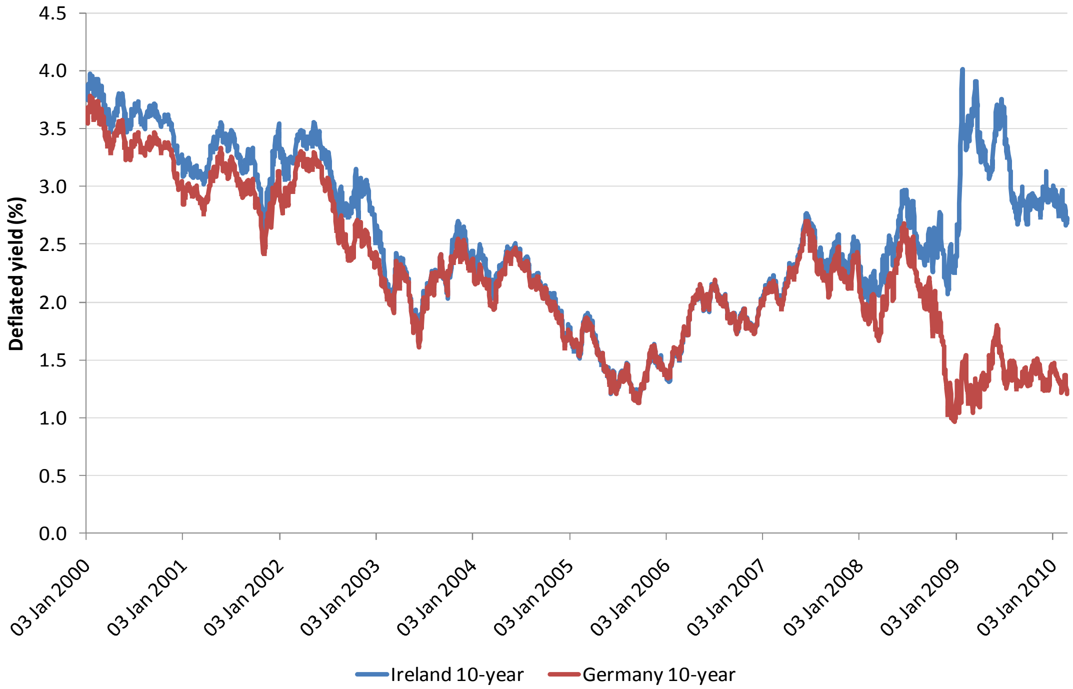
Source: Bloomberg

We note that the sport rate on the 2020 OATi is 1.5%, somewhat down from 2.3% this time last year and below the latest 12 month average of 1.7%.

RoI relative to German risk-free rate

Evidence of an Irish premium in risk-free rates relative to German rates is presented in Figure A7, which depicts deflated yields on 10-year nominal Irish and German sovereign debt.

Figure A7: Deflated yields on 10-year Irish and German benchmark sovereign bonds



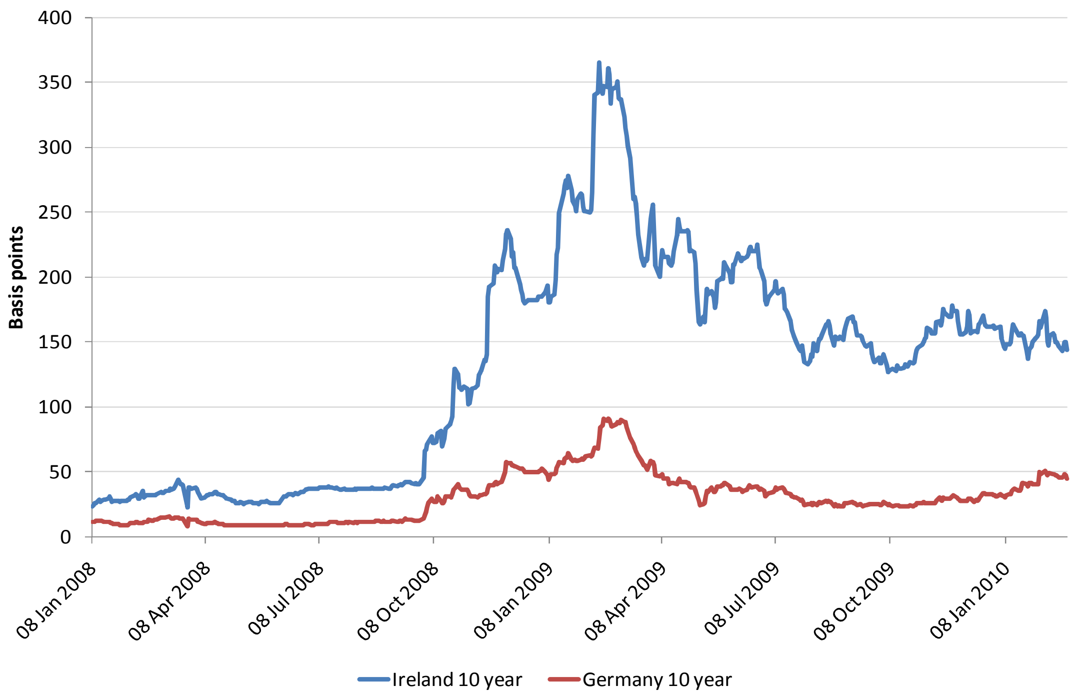
Sources: Bloomberg, ECB, CEPA analysis

The figure shows that up until the collapse of Lehman Brothers the yields on Irish and German 10-year debt tracked each other very closely. However, the financial crisis caused investors to evaluate member states of the Euro-zone differently and since then there has been a divergence between yields on Irish sovereign debt and its German equivalent. The spread of Irish yields over German peaked at around 200bps but have since narrowed to around 125bps.

The most likely reason for this divergence is market sentiment toward the relative riskiness of the two debt issuers. That is, investors came to see holding Irish debt as being relatively more risky than German debt and have priced this in to required yields. One way of testing this view 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 A8 presents spreads on 10 year CDS for both Irish and German sovereign debt. The lower the spread in basis points the less risky investors perceive the threat of the debt defaulting.

Figure A8: 10-year Irish and German Credit Default Swaps



Source: Bloomberg

The figure shows that prior to the Lehman Brothers collapse the premium on Irish CDS above German was stable at around 25–30bp. Following the collapse of Lehman (and other financial institutions) the spreads on both Irish and German CDS increased significantly with Irish spreads far outpacing their German counterparts causing the margin between the two to reach a peak of around 250bps. Since then the margin has narrowed considerably such that it is currently around 100bps.

A.5.2.3.Debt premia

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.

United Kingdom

Figure A9 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 currently lie slightly above their pre-crisis levels for all maturities.

Figure A9: Spreads on BBB rated UK corporate debt

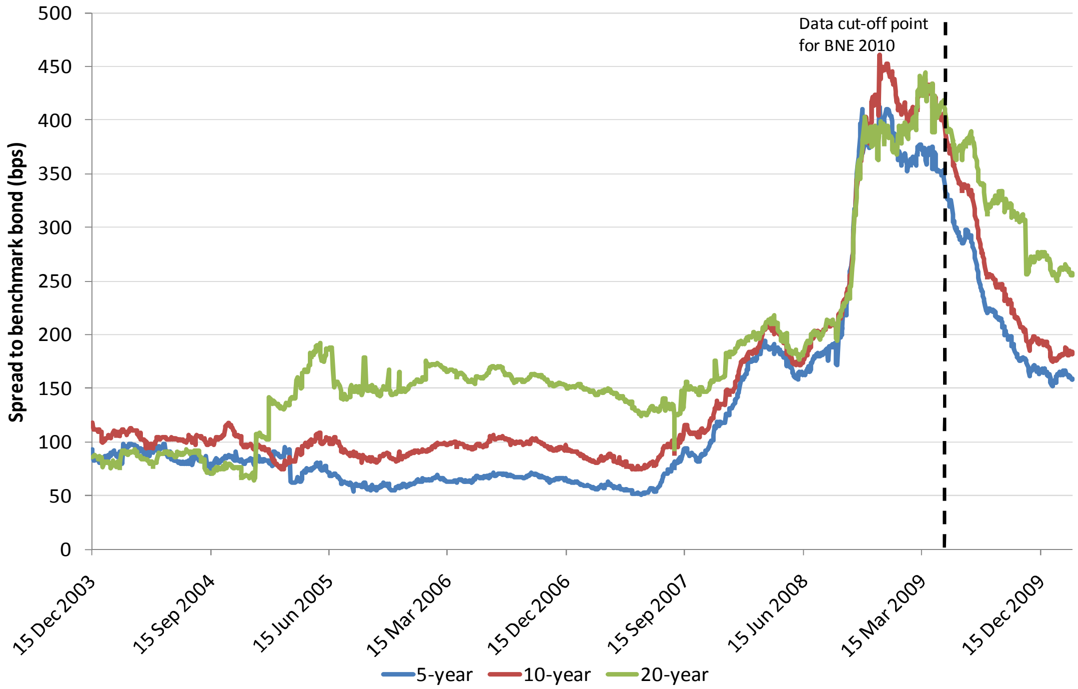
Source: Bloomberg, CEPA analysis

Current spot rates of spreads range from 140bps for 20-year debt to 175bps for 5-year debt, with the spread on 10-year debt at 160bps. At the time of our report on BNE 2010, the debt premium for all three maturities was around 300bps.

RoI

Figure A10 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 we also note that the spread has remained at unusually high levels for 20-year debt.

Figure A10: Spreads on BBB rated European corporate debt



Source: Bloomberg, CEPA analysis

Current spot rates of spreads range from 160bps for 5-year debt to 260bps for 20-year debt, with the spread on 10-year debt around 180bps. At the time of our report last year, the debt premium was around 350-400bps.

A.5.2.4.Recent utility company debt issues

United Kingdom

Table A2 contains evidence on some of recent issues of sterling denominated utility company debt raised in the UK.[19] It shows the (nominal) yield and spread at issue, as well as the current yield and spread. We limit our analysis to debt of maturity between five and 15 years.

The key observation to make is that spreads narrowed significantly across all credit ratings since the summer of 2009 compared to their levels a year ago.

[19] 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	Nominal yield at issue (%)	Spread at issue (bps)	Nominal yield on 26/2/2010 (%)	Spread on 26/2/2010 (bps)
Severn Trent	22/01/2009	2018	400	BBB+	6.0	246	5.1	138
Centrica	10/03/2009	2022	400	A-	6.2	292	5.5	150
United Utilities	25/03/2009	2022	375	BBB+	5.9	245	5.6	152
ENW Capital	21/07/2009	2015	300	BBB	6.8	374	4.7	187
ENW Finance	21/07/2009	2021	200	BBB+	6.2	234	5.6	153
Scottish & Southern	30/09/2009	2018	500	A-	4.9	153	5.0	135
Southern Gas	02/11/2009	2018	300	BBB	5.1	168	5.1	137
EDF LPN	12/11/2009	2016	300	A	4.9	167	4.6	132

Sources: Bloomberg, CEPA analysis

RoI

Table A3 contains evidence on some of recent issues of euro denominated utility company debt raised in the Euro-zone during 2009 and 2010. It shows the (nominal) yield and spread at issue, as well as the current yield and spread. We again limit our analysis to debt of maturity between five and 15 years.

As with UK debt issuances, the key observation from Table A3 is that spreads narrowed significantly since the summer of 2009 compared to their levels a year ago.

Table A3: Recent Euro-zone utility debt issues

Company	Issue date	Maturity	Amount (€m)	S&P credit rating	Nominal yield at issue (%)	Spread at issue (bps)	Nominal yield on 26/2/2010 (%)	Spread on 26/2/2010 (bps)
Elia (Belgium)	22/04/2009	2016	500	A-	5.1	230	3.4	108
Iberdrola (Spain)	04/06/2009	2019	125	A-	5.7	203	4.1	107
Bord Gais (Ireland)	16/06/2009	2014	550	A-	5.3	262	3.9	212
Veolia (France)	29/06/2009	2017	250	BBB+	5.3	217	3.8	121
Gas Natural (Spain)	09/07/2009	2019	500	BBB+	5.8	251	4.6	157
EWE AG (Germany)	16/07/2009	2021	500	A-	5.1	181	4.3	128
Enel (Italy)	19/11/2009	2019	125	A-	4.5	130	4.2	111
Enel (Italy)	24/11/2009	2020	100	A-	4.4	116	4.2	109
Hera Spa (Italy)	03/12/2009	2019	500	A-	4.5	135	4.5	140
TenneT (Netherlands)	09/02/2010	2022	500	A-	4.5	135	4.3	116

Sources: Bloomberg, CEPA analysis

A.5.3. Regulatory precedent

In the UK and RoI there have been four regulatory determinations since we complied our report on the cost of capital allowance for the 2010 BNE. Table A4 summarises the risk-free rate, debt premium and overall cost of debt used in each of those determinations.

Table A4: Recent regulatory decisions on the cost of debt

Regulator	Decision	Risk-free rate	Debt premium	Cost of debt
United Kingdom				
Ofgem	Electricity distribution (2011-2015)	2.0%	1.6%	3.6%
Ofwat	Water & sewerage (2011-2015)	2.0%	1.6%	3.6%
CAA / CC	Stansted airport (2009-2014)	2.0%	1.4% - 1.7%	3.4% - 3.7%
Ireland				
CAR	DAA (2010-2014)	2.5%	1.6%	4.1%

Sources: Ofgem, Ofwat, CAA, CAR

There appears to be a consensus among UK regulators that a risk-free rate of 2.0% is appropriate in the regulatory context. There also appears to be a consensus around the approximate level of the debt premium in the UK and Ireland. We note, however, that the above regulators set their cost of capital allowances for five-year control periods, meaning that they have an incentive to aim up for observed levels in order to allow for the possibility of movement in market rates during the control period. Such an adjustment is less appropriate in the case of the BNE, where the control is fixed for only one year.

A.5.4. Conclusion on the cost of debt

Given the above, we can summarise the changes in the components of the cost of debt relative to our analysis last year as follows:

- there has been little change in the risk-free rate either in the UK or the RoI; and
- the debt premium has narrowed substantially by around 100bps in the UK and around 150bps in the RoI.

Table A5 brings together our view on the cost of debt faced by a notional BNE peaking plant in the UK and the RoI.

Table A5: Summary range for BNE cost of debt

	RoI Low	RoI High	UK Low	UK High
Risk-free rate	1.50%	2.50%	1.50%	2.00%
Debt premium	1.50%	2.50%	1.50%	2.00%
Cost of debt	**3.00%**	**5.00%**	**3.00%**	**4.00%**

Source: CEPA analysis

We, therefore, recommend that the appropriate cost of debt to allow a BNE peaking plant investment in the RoI for 2011 lies within the range 3.00% – 5.00% and for the UK in the range 3.00% – 4.00%.

A.6. Cost of equity

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

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

where $CoE =$ cost of equity

$r_f =$ risk-free rate

$ERP =$ equity risk premium for the market portfolio

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

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

A.6.1. Equity risk premium

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

Our approach in the 2010 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 A6 summarises their most recent analysis.

Table A6: Dimson, Marsh and Staunton estimates of the ERP

	Arithmetic mean 1900-2008	Geometric mean 1900-2008	Geometric mean 1900-2009
United Kingdom	5.0%	3.6%	3.9%
RoI	4.4%	2.4%	2.6%
Europe	5.0%	3.6%	3.9%

Source: Dimson, Marsh and Staunton

CEPA considers it prudent for regulators to take account of arithmetic mean averages, which are higher. While we note a slight increase in the estimates when data for 2009 is included, we consider that our proposed range from last year (4.5% - 5.0% for both the RoI and the UK) remains appropriate.

We note, however, that some commentators have suggested a relationship between the business cycle and the ERP. For Ofwat's PR09 price control review, Europe Economics (EE) argued that a crisis ERP of 20% greater than the usual ERP was appropriate. On this basis, a crisis ERP of 6.0% was derived (on foot of a non-crisis ERP of 5.0%). Recognising that crisis conditions are unlikely to prevail for the full term of the price control EE give the crisis WACC derived from the uplifted ERP a 45% weighting in the calculation of the overall WACC. This suggests the crisis would continue for approximately 36 months[20].

We recognise that there are arguments either way for the inclusion of a crisis ERP and its influence on the equity required by investors. For this reason we believe it is appropriate to settle on an ERP closer to the top end of the relevant range identified.

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:

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

where $cov(r_e, r_m)$ = 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.

[20] Or more likely that a crisis ERP will prevail for longer than 36 months but a declining rate until a normal non-crisis ERP reverts.

A.6.3. Regulatory precedent

Table A7 summarises the cost of equity parameters used by the four regulatory decisions since our report on the cost of capital for BNE 2010.

Table A7: Recent relevant decisions on the ERP

Regulator	Decision	Risk-free rate	ERP	Equity beta	Cost of equity
United Kingdom					
Ofgem	Electricity distribution (2011-2015)	2.0%	4.7%	1.0	6.7%
Ofwat	Water & sewerage (2011-2015)	2.0%	5.4%[21]	0.9	7.1%
CAA / CC	Stansted airport (2009-2014)	2.0%	3.0%-5.0%	1.0 – 1.2	5.0%-8.2%
Ireland					
CAR	DAA (2010-2014)	2.5%	5.0%	1.2	8.5%

Source: CEPA

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.

A.6.4. Conclusion on the cost of equity

Using our common estimates 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 A8.

Table A8: Summary range for BNE cost of equity

	RoI Low	RoI High	UK Low	UK High
Risk-free rate	1.50%	2.50%	1.50%	2.00%
ERP	4.50%	5.00%	4.50%	5.00%
Equity beta	1.20	1.30	1.20	1.30
Cost of equity	**6.90%**	**9.00%**	**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 6.90% – 9.00% and for the UK in the range 6.90% – 8.50%.

A.7. Taxation

CEPA is of the view that the WACC is not necessarily the most appropriate mechanism to allow for taxation costs and that there is merit in forecasting actual taxation costs and allowing for

[21] 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.

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
- 28.0% for the UK.

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 A9. This should be compared with the real pre-tax WACC decision by the RAs for the 2010 (also shown in the table below).

Table A9: Consortium estimate of BNE weighted average cost of capital

	RoI			UK		
	2010	**Low**	**High**	**2010**	**Low**	**High**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
Debt premium	3.50%	1.50%	2.50%	3.00%	1.50%	2.00%
Cost of debt	**5.38%**	**3.00%**	**5.00%**	**4.75%**	**3.00%**	**4.00%**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
ERP	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.20	1.30	1.25	1.20	1.30
Post-tax cost of equity	**7.81%**	**6.90%**	**9.00%**	**7.69%**	**6.90%**	**8.50%**
Taxation	12.5%	12.5%	12.5%	28%	28%	28%
Pre-tax cost of equity	**8.93%**	**7.89%**	**10.29%**	**10.68%**	**9.58%**	**11.81%**
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**6.80%**	**4.95%**	**7.11%**	**7.13%**	**5.63%**	**7.12%**

Source: CEPA analysis

We, therefore, recommend that the appropriate WACC allowance for a BNE peaking plant investment in the RoI for 2011 lies within the range 4.95% – 7.11% and for the UK in the range 5.63% – 7.12%.