Costs of a best new entrant peaking plant for the calendar year 2010

A report for the Regulatory Authorities

12 June 2009

Final Report

FOR PUBLICATION

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 in association with Parsons Brinkerhoff (PB) are pleased to submit this draft report on the costs of a Best New Entrant (BNE) peaking plant for the calendar year 2010 to the Regulatory Authorities (RAs).

1.2. Purpose of this document

This independent report provides CEPA and PB's estimate of the fixed costs that a rational investor would face in constructing and operating a peaking plant to enter the Single Electricity Market (SEM) in 2010. It is therefore designed to inform the RAs determination of the size of the capacity payment pot for 2010.

This document has been informed by discussions with the following stakeholders:

- The RAs – who have provided useful input in respect of previous approaches and in outlining issues which, for reasons of regulatory certainty, are treated as given within this report.
- System Operators – who have provided views on a number of the characteristics which the BNE plant must be capable of meeting and the criteria for identifying shortlisted plants.
- Generators and other market participants – who were invited to attend a workshop facilitated by the RAs in which CEPA/PB outlined their initial thoughts on approach and methodology and invited comments.

We would like to thank stakeholders for their useful suggestions and contributions.

1.3. CEPA and Parsons Brinkerhoff

This report has been developed by CEPA and PB working in partnership.

- 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, developing generation tariffs and tariff methodologies, and advising on relevant incentive issues. CEPA's experience includes extensive work in the Republic of Ireland (RoI) energy sector, including a number of assignments for the Commission for Energy Regulation (CER), the UK (including Northern Ireland (NI)), Europe and internationally.
- Parsons Brinckerhoff (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 CER and are currently advising the UK Regulator, Ofgem. We have extensive experience in generation, transmission and distribution in both the RoI and NI.

1.4. Project context

1.4.1. The Single Electricity Market

As a first step towards creating an 'All Island Energy Market' combining NI and RoI, an integrated wholesale electricity market, the Single Electricity Market (SEM), was initiated in November 2007. The SEM is a gross mandatory pool, meaning that all electricity generation (>10MW) on and any imports into the Island of Ireland must be sold to the pool, while all wholesale electricity for distribution or export must be bought from it. Generators of electricity submit bids which reflect their short-run marginal cost (in accordance with the bidding code of practice), with the lowest cost bidder being the primary source of electricity. The 'merit order' for generation is thus determined by a model of cost efficiency.

The 'System Marginal Price' (SMP) is comprised of the shadow price and uplift; uplift covering start-up and no load costs. The shadow price is set every 30 minutes by the bid of the last generator to be despatched to meet demand in that period, and all generators receive the same SMP. Generators also receive a capacity payment for each unit of capacity made available to the market, regardless of whether their supply is required. Around €575m was allocated for the 'Capacity Payments Mechanism' (CPM) for 2008, and €640m for 2009. The CPM is intended to improve incentives for generation investment by off-setting a proportion of the fixed cost of generating or keeping plant available.

All market participants operate under the SEM Trading and Settlement Code (TSC), which sets out the trading and settlement arrangements for wholesale electricity transactions in the pool. The SEM is regulated by the SEM Committee, whose decisions are implemented by the RAs.

1.4.2. The Capacity Payment Mechanism

Objectives

The capacity payment is an important part of the SEM. The RAs introduced a capacity payment mechanism in order to fulfil the following objectives:

- Ensure capacity adequacy and system reliability by incentivising investment in new plant and the availability of installed capacity.
- To the extent practicable, increase stability and reduce volatility price relative to an energy only market.

- Provide a transparent, predictable and simple to administer mechanism which can lower the risk premium required by investors in generation.
- Send efficient price signals about the need for long-term investment, striking a balance between the level of installed capacity and what generators are willing to pay for.
- Strike a fair balance between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

A well functioning CPM therefore provides benefits to existing market participants, potential new market entrants and ultimately customers.

Structure

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 7,356MW for 2009); and
- a price element.

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.

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 approach.
- 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.
- Section 6 provides details of the infra-marginal rent and ancillary service revenues the plant could be expected to earn.
- Section 7 sets out the overall estimate of the BNE price.

The document also includes three annexes.

- Annex 1: CEPA/PB Long List of technology options.
- Annex 2: Performance impacts of water injection.
- Annex 3: Supporting evidence on the Cost of Capital.

2. CEPA/PB Approach

In this section we set out the high-level approach adopted by CEPA and PB in establishing the costs of a BNE peaking plant.

2.1. What is a BNE plant?

In theory the BNE plant is the plant which would serve the marginal MW of generation at the point when the market is in equilibrium. Therefore it is the plant which would serve the market in periods when the expected loss of load probability (we understand eight hours per year) came about.

In practice no market is in equilibrium and it is impossible to consider actual 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 real market evidence. It is worth noting that there currently appears to be a significant interest in the development of peaking capacity in Ireland.

2.2. Issues to address in considering 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 decisions that would have been taken and the costs faced by a rational investor seeking to bring a plant to market in 2010. 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
Who is the BNE peaking plant investor?	What would a rational investor look like? Is that party independent or vertically integrated? Are they considering opportunities across the World, Europe or solely Ireland/ UK?
What is the appropriate technology choice?	What size is the plant? What specification (due to operational or environmental factors) does the plant have to meet? What does it cost?
Where are they locating?	Where can it locate? What does that mean for fixed costs? What does this mean for operational costs (i.e. transmission charges)?
Why would a BNE choose to enter the SEM?	Capacity payment revenues? Infra-marginal rent and ancillary services revenues?

Key question	Other issues/questions to consider
	What is the required cost of capital?

CEPA and PB note that a medium term review of the capacity payment mechanism is under way. However CEPA/PB understand and appreciate the need to maintain regulatory certainty and, to the extent practicable, maintain an approach that is consistent with that taken in previous years. The project's terms of reference identified a number of parts of the methodology for calculating BNE costs as given. These are:

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

2.2.1. Medium term review of the CPM

CEPA/PB are aware that a medium-term review of the CPM is currently being undertaken by the RAs in consultation with market participants. We understand that the medium term review will seek to address issues around the calculation and long-term stability of the CPM and consider the interaction between the energy market, the capacity market and ancillary services markets. Issues relating to the medium-term review are outside the scope of this report.

2.3. Approach

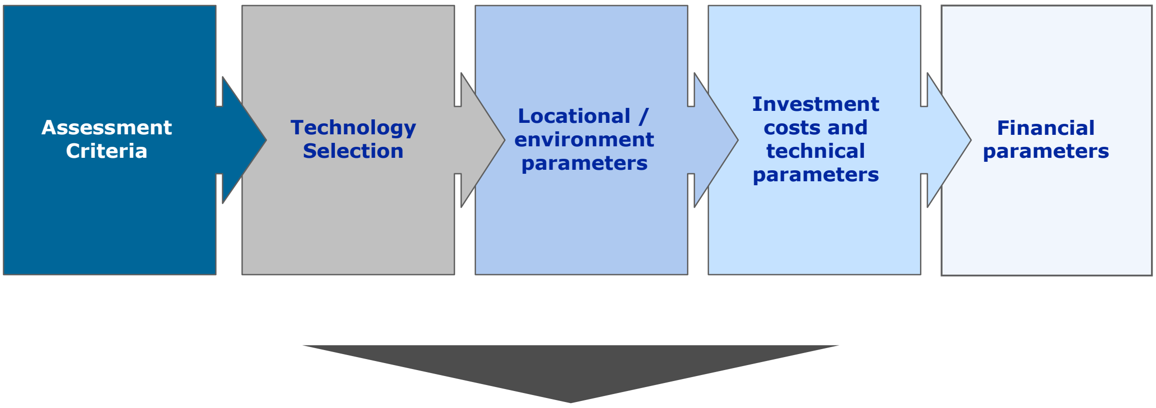
CEPA/PB are aware of the importance of the CPM to existing and prospective investors in generation and the consequences of the size of the CPM pot (the BNE price multiplied by the capacity requirement for customers). In developing an approach to calculating the BNE pot for 2010, we have had regard to responses to previous year's consultations and have, to the extent practicable, sought to address comments and criticisms. In particular, we are aware that parties felt that it was not sufficiently simple to understand the approach used to determine costs and that important assumptions were at times opaque.

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 2010.
- It may be located in either the RoI or NI and can be fuelled by whatever is most efficient.
- The plant will serve the final MW of demand, hence it will 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



Fixed cost of a BNE peaking plant for 2010

Our approach, in common with that used in previous years, has been to identify the best 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.

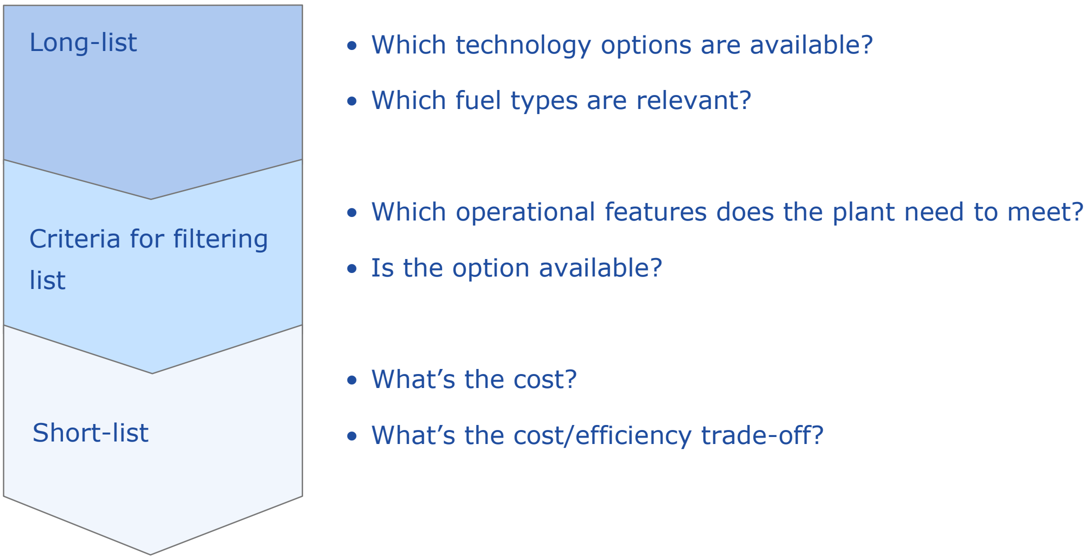
3. TECHNOLOGY SELECTION

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", 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.

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

As a first step the team developed a long-list of options, capturing all available technology options which might reasonably be described as a peaking plant (with unit capacities between 35 and 200MW). This list, which is available in Annex 1, was designed to be an exhaustive list covering various manufacturers and fuel-types (gas, distillate, heavy-fuel oil). Other options such as second-hand plant, the interconnector and combinations of smaller-units were also considered and are discussed briefly below.

Since the notional peaking plant was to be aimed at supplying the last MW on the generation stack, with infra-marginal rent deductions not being considered prior to technology selection, CCGT was not considered comprehensively for the BNE 2010. Likewise, in common with the BNE 2009 study, pumped storage was not considered due to the limited number of suitable sites and the desire for relative stability of the CPM pot year on year. Discussions with the RAs and stakeholders also led CEPA/PB to exclude the interconnector as an option due to uncertainties that it would be capable of supplying the final MW of generation in all circumstances.

3.2.1. Fuel choice

In previous years, 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 liquidity in secondary gas trading.

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 respondents and seminar attendees views that further developments in the gas market meant gas was a credible fuel source, as well as fuel security considerations. 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 only an interruptible product exists in NI.

3.2.2. Environmental requirements

In considering the appropriate choice of technology, we need to be mindful of environmental requirements. 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, as set out in existing legislation, while taking into account the expected operational profile of the plant. Were a rational investor likely to invest in emissions reduction capability based on a reasonable expectation of changes in environmental policy (rather than, for example, retrofitting abatement technology at a later date) this would also need to be reflected. Seminar attendees comments coupled with past year's decisions did not identify any new pieces of environmental legislation which parties felt would influence the design of a BNE plant by a rational investor. However, parties identified the need to comply with Best Available Techniques, as set out in guidance to support the Large Combustion Plant Directive (LCPD) and Industrial Emissions (Integrated Pollution Prevention and Control) Directive.

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

3.3. Criteria for reducing the list

Following discussions with the RAs, Transmission System Operators (TSOs) and generator comments, we developed a series of pass/fail criteria for filtering the long list. These are shown 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.
Does the technology have a proven track-record (typically defined as 3 examples of over 8,000 running hours)?	This would determine the ability to acquire insurance for the plant.
Are the unit sizes between 30 and 200MW?	Deemed by TSOs to be an appropriate range.
Can the technology option ramp up to full load in less than 20 minutes?	The TSOs identified this as a necessary operational criteria for a peaker.
Can the technology option fire liquid fuel?	RoI has a dual fuel obligation which the peaker would need to be capable of meeting.
Can it meet NOx requirements?	Must meet environmental legislation.

Following discussions with generators, in which we outlined the approach described above, we received a number of comments and feedback on these criteria, which are briefly summarised below:

- *Whether a manufacturer offers an EPC contract should be a relevant criterion* – While we agree that it is important that a generator must be able to secure an EPC contract, we do not consider this must necessarily be provided by the manufacturer. We would suspect that, were a manufacturer not to offer such a contract, it would be because other parties operating in the market could do so at as competitive, or a more competitive, price. Hence we do not propose to include this as a criteria.
- *The GE LMS100 is being actively considered by investors on the Island of Ireland* – Attendees at the generator seminar noted that LMS100 plant was being considered by investors in Ireland and provided evidence to suggest that insurers were prepared to insure such plant. On this basis, despite CEPA/PB receiving a mixed assessment from lead insurers (some still considering it prototypical), we revised our view that the plant would not meet the proven track record criteria and included the LMS100 in the selection of plant which were analysed further.
- *Aggregations of small-plant should be considered as an option for a peaking plant* - An attendee at the generator workshop considered that the increasing presence of aggregators, which combine smaller, more geographically dispersed, generation technologies should be viewed as an option for the peaking plant. While we

agree that this type of arrangement may provide a candidate for the peaking plant in future, we were not presented with evidence (as was the case with the LMS100) that it would be possible to insure this configuration of plant and, as such, we did not consider that the option met the proven track record criterion.

3.3.1. Second-hand plant

In considering the suitability of second hand plant for the BNE, the following can be concluded from a snapshot review of available second hand plant equipment:

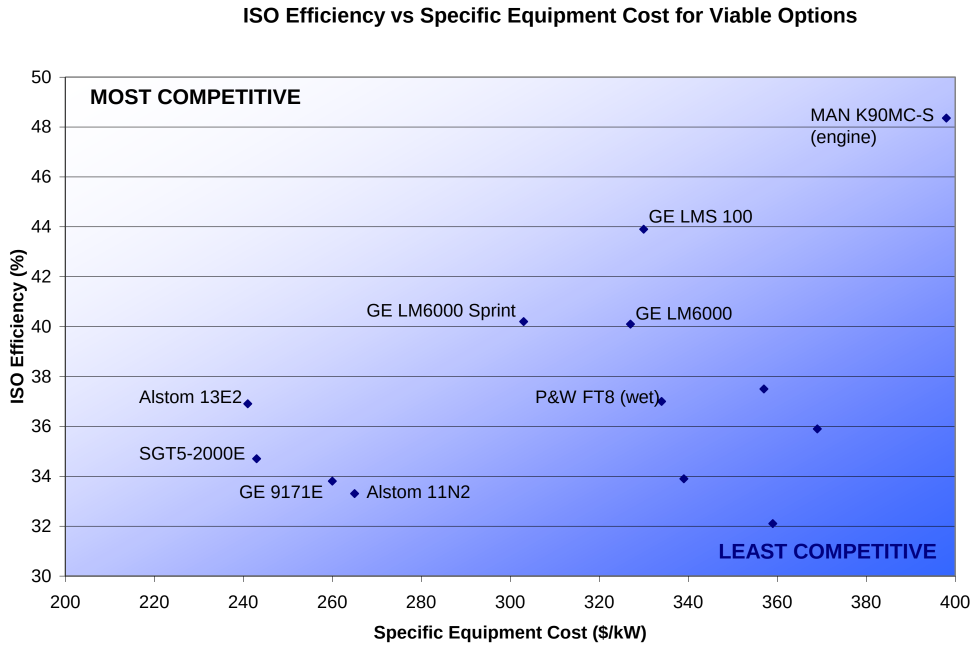
- mainly GE machines are available;
- mainly 40MW nominal machines are available;
- larger machines for sale are typically new machines, at similar-to-GTW prices; and
- mainly 60Hz machines are available.

The likelihood of emissions compliance of an older GT and the potentially uncertain start-up reliability of a second hand machine are other factors that might deter investors. As a result of these findings, and the overall impression of the second hand market, we would conclude that it would just be difficult to anticipate such an opportunity for the purposes of this study.

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' ISO efficiency and equipment cost, as published in the Gas Turbine World 2009 GTW Handbook (an internationally recognised plant cost database), as a broad secondary filter. This evaluation is shown in the diagram below.

Figure 3.2: 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. We therefore chose to exclude plants which had a high equipment costs and a relatively low efficiency from the further analysis.

3.4.1. Is efficiency important?

Our discussions with generators raised the question of whether a rational investor in a peaking plant would pay particular attention to the efficiency of the unit? It was suggested that, given the peaking plant would be expected to run only between 2% and 5% of the time, cost would be by far the most relevant consideration.

As such, generators suggested that options towards the top right of the diagram should be excluded from the analysis. We have incorporated this feedback from market participants in identifying the candidate plants.

3.4.2. Final candidate plants

Having applied the filters described above and removed the plant towards the right of the diagram above, we identified the most practicable generating unit options for the BNE technology likely to yield the lowest BNE price. In order to ensure a robust analysis, more efficient GTs such as the LM6000 Sprint 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 SGT5-2000E

- 4 x GE LM6000 PC Sprint
- 3 x P & W FT8 Swift Pac 60 (wet)

The Pratt and Whitney FT8 was included in the candidate list following the forum with the generators, since the relative increase from equipment cost to EPC cost for these machines tends to be lower as a result of its ready-to-install nature. The purpose for selecting more than one machine for the last two (aero-derivative) options was partly to achieve the TSOs preference for a plant capacity in excess of 70MW, but also to capitalise on specific cost reductions and to achieve similar outputs for all options.

A departure from last year's modelling has been to include the increase in power output resulting from the use of water injection for NOx control in the industrial options (Siemens and Alstom). This mode of operation, while reducing the efficiency, provides a greater power output for each unit and is further justified in Annex 2. The SGT5-2000E DLN combustion system can not 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

3.5.1. State of the EPC market

We are aware that there is a perception that EPC prices have fallen considerably over the past year. While there is evidence of manufacturers being more willing to engage with project developers, a fall in prices for simple cycle plant has not been borne out by PB's recent experience. Power plant prices continued to rise last year into August, and for GTs and simple cycle plant, the costs have generally stabilised. While for combined cycle plants a drop in heat recovery steam generator costs has been evidenced since September 2008, the main impact of this is that fixed price contracts have been re-introduced. The back-log of work for some CCGT EPC contractors is still in excess of two years, so a rapid softening of the market is unlikely. We consider that the flattening of simple cycle plant prices may also be for the following reasons:

- GT manufacturers typically have long lead-time contracts with their raw material suppliers and the reduction in commodity prices has only recently started to have an impact on GT prices, though this impact is slight since energy and raw material costs account for less than 15% of the price.
- The market is global and demand for medium to large GTs (greater than 40MW) is still significant, especially in emerging markets and the Middle East in particular. While the oil and gas industry may have delayed or cancelled projects, the GTs they predominantly require are of the small to medium range. In PB's experience, utilities around the world have generally continued with plans to implement larger GT power plants.

Consequently, we would anticipate that current EPC prices for simple cycle plant are approximately equivalent or marginally higher than those seen in May 2008. The expectation is that prices will fall for the remainder of this year, but as the notional BNE plant is expected to come on line during 2010, our assumption is that financial close would have already been achieved.

3.5.2. Approach to EPC Cost Estimation

Our approach to EPC cost estimation included two elements:

- Model the shortlisted plants in GT PRO[1].
- Adjust 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 (as attendees at the workshop noted, 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). PB therefore uses relevant comparators to develop a series of adjustment factors which can be used to calibrate modelling results with practical experience.

While in the past three years (up to the present time) PB have found CCGT EPC prices to be in the order of 40% higher than the PEACE estimate when using the default multipliers of the relevant country, they currently find on average a close correlation between simple cycle plant EPC costs in Western Europe and the PEACE Version 19 estimates when using the applicable default multipliers.

For reasons of commercial confidentiality it is not possible to provide the details of the projects from which the adjustment factor was derived. Typically, for CCGT estimates, the multipliers for specialised equipment, "other" equipment, labour and commodities are adjusted separately in PB's calibration process. However, for SCGT plants, due to the simpler nature of the EPC scope and the smaller adjustment currently required, a single uplift on the EPC cost estimate from PEACE is considered appropriate. For this study, the single uplift on the EPC cost estimate from PEACE using default UK multipliers in GT PRO Version 19 has been set at 3.8%. We are aware that specific market influences can cause significant variation in EPC costs and that specific tenders by a GT manufacturer may differ significantly from a PEACE estimate from time to time; however, for the sake of being robust and remaining impartial, the PEACE database has

[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.

been used as the platform from which a PB adjustment has been applied uniformly to all the candidate GT plants.

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 below. 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.

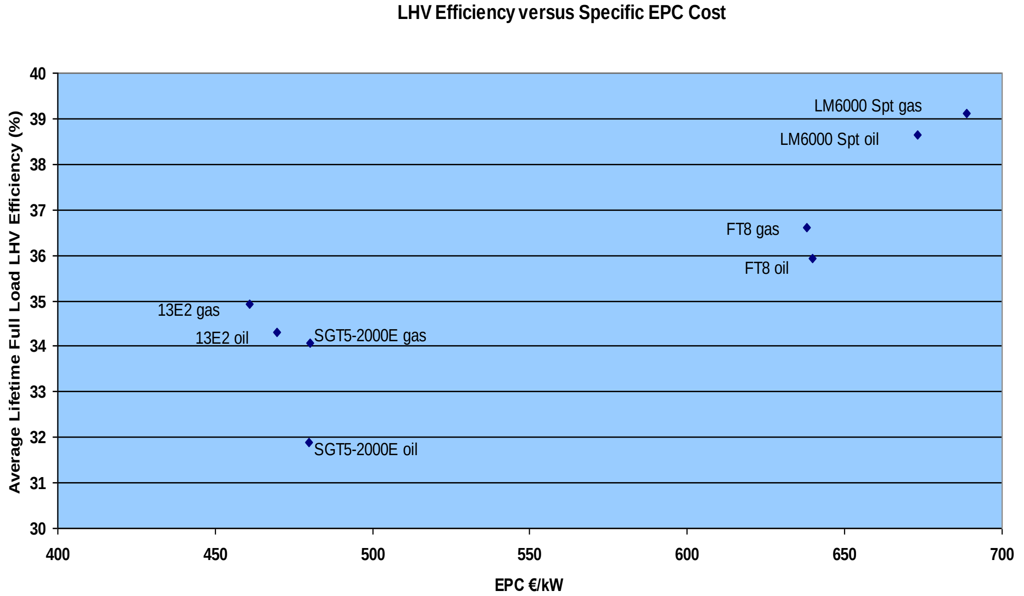
Table 3.3: Final EPC cost assessment and power output for short-listed plants.

Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)[2]
1 x Alston GT13E2	Distillate	190.1	89.4
	Gas	193.6	89.4
1 x SGT5-2000E	Distillate	166.6	80.0
	Gas	166.8	80.1
4 x GE LM6000 PC Sprint	Distillate	193.3	130.2
	Gas	194.5	133.9
3 x P & W FT8 Swift Pac 60 (wet)	Distillate	183.6	117.5
	Gas	184.9	118.0

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.

[2] Please note that approximately 5% contingency is included in the EPC cost estimates.

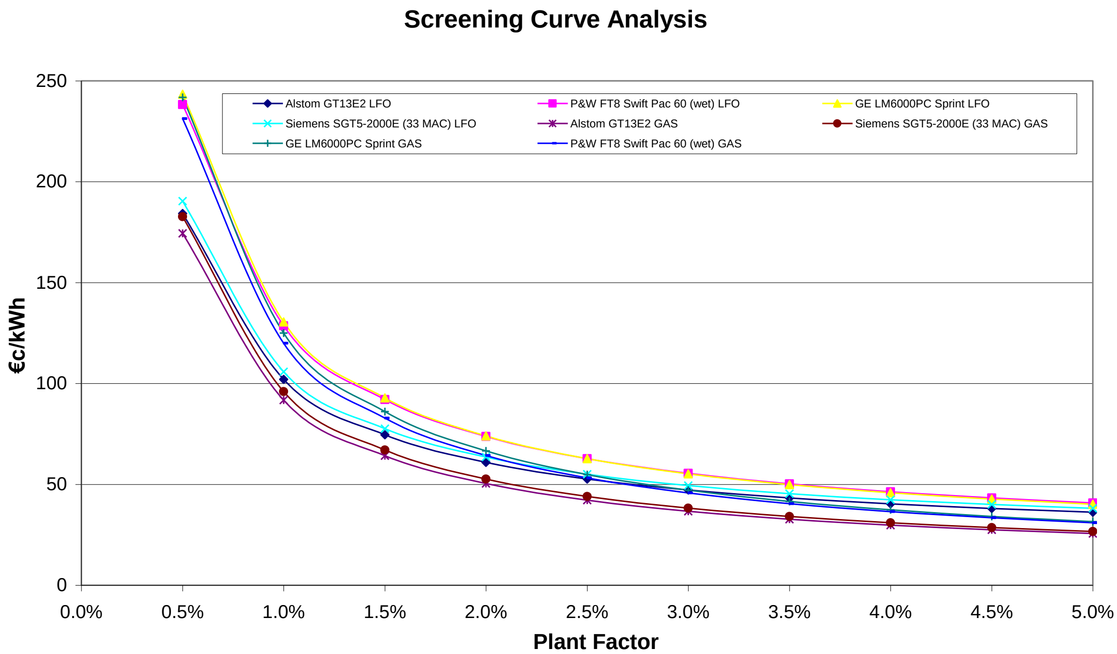
Figure 3.3: Efficiency and EPC cost trade-off for short-listed plant



3.6. Chosen technology option

While the overall investment and fixed annual costs are considered in more detail in Section 4, these costs were incorporated into a screening curve model that compares the annualised specific cost of each short-listed option for varying plant utilisation factors. This allows one to identify the most appropriate technology option based on an expectation of load factor. The results are presented below in Figure 3.4.

Figure 3.4: Generation cost vs plant utilisation factor



From the screening curve analysis, it is evident that the more efficient aeroderivative options are not cheaper on an annualised basis for plant factors of 5% or less. Consequently, as the intent of the notional plant is that it would be used less than 5% of the time, the LM6000 and the FT8 do not present the cheapest applicable BNE option. As with the EPC specific costs shown in Figure 3.3, in which the 13E2 has the edge over the SGT5-2000E, so too with the generation costs it proves to be cheaper no matter what the plant utilisation factor or fuel type is.

On the basis of the approach outlined above and the results shown, in CEPA/PB's opinion, the **BNE GT for 2010 is an Alstom GT13E2**. 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 and dual fuel options of 3 days at maximum plant load.
- Water storage and treatment capability for 3 days of water injection at 1:1 water to fuel (mass basis) ratio 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: Key findings for BNE technology selection

Key recommendations:

- 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 is 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. EPC costs, which are the primary driver of technology selection, were considered in Section 3 and are summarised but not discussed further here.

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.

4.2.1. Republic of Ireland

As we understand it, various investors are considering siting new peaking capacity in the RoI. Hence any of the sites currently targeted by investors might be considered to be appropriate locations for a BNE plant. However, in common with approaches taken in previous years, we have not determined a specific location (which would itself be hypothetical) but considered costs for a notional plant at a notional location. This assessment has been informed by consideration of various costs which would likely to be faced at relevant candidate sites.

4.2.2. Northern Ireland

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). For completeness, we have considered sites around Belfast that could make use of agricultural land, but have ruled these out due to the likely time lag in obtaining planning approvals.

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. The PEACE estimate was increased by 3.8% in accordance with PB project experience to yield €89,397,000 for the distillate option and €89,421,000 for the dual fuel (gas for normal operation) option.

The period over which the Alstom GT13E2 plant is expected to be built, from financial close to plant hand-over, has been estimated at 18 months. While Alstom do have 13E2s available at present, 18 months does represent a significant reduction from a year ago when, for SCGT plant of this nature, we would have estimated 20 – 24 months. The reason for maintaining an 18 month period for construction and commissioning is that the transformer is likely to be on the critical path, with a possible 12 month lead time. Recent large orders of other similarly-sized equipment requiring transformers have informed this decision.

Table 4.1: EPC Costs (current prices)

Location	Fuel Type	EPC Costs
NI	Distillate	€89,397,000
	Dual	€89,421,000
RoI	Distillate	€89,397,000
	Dual Fuel	€89,421,000

4.3.2. Site procurement

In considering the appropriate locations in NI and the RoI for the candidate BNE plants, it is necessary 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 and the ongoing operational costs.

For the RoI, we consider that a BNE investor would be able to obtain agricultural land, and following discussions with the RAs, that this would most likely be in the south east or midlands. As noted above, for NI, we consider Belfast West to be the appropriate site for costing purposes.

In order to inform likely costs of land acquisition, we contacted a property market expert and sought a view on a reasonable value for the Belfast West site and for sites in the RoI. We were made aware that the Belfast West site would most likely be leased rather than acquired, but we have, for consistency, presented the land cost as a capital value, taking account of both commercial/ industrial property land values in Belfast and the likely (capitalised) value of a lease. These values take account of recent drops in market values from recent highs. For RoI, we understand that market values for greenfield land are unlikely to fall due to the restricted nature of the market (although recommended figures are below those chosen last year). This information is shown in the table below.

Table 4.2: Assessment of land costs

Location	Required area (m^2)	Estimated site cost (€)
NI	20,600	1,425,288
RoI	20,600	1,527,095

4.3.3. Electrical connection costs

A significant driver of the costs of a site are 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.

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	7,400,000
RoI	5,676,000

4.3.4. 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 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	400,000	3,380,000

4.3.5. Owner's contingency

While last year the allocation for owner's contingencies was set in the decision paper at approximately 1.6% of the EPC cost (excluding electrical interconnection), from PB's applicable project experience, a value of approximately 5% would seem to be more commonly provided for in the financing of projects. 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. Based on PB's project experience, 5.2% of the value of the EPC cost has been attributed to owner's contingency. This translates to a figure of €4,648,648 for the distillate plant and €4,649,908 for the dual fuelled plant.

4.3.6. Financing, Interest During Construction and construction insurance

Our financing, IDC and construction insurance costs have been estimated as a proportion of EPC costs based on CEPA/PB's past experience. Our estimates are shown in Table 4.5 below.

Table 4.5: Financing, interest and insurance costs

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Financing	1,788,000	1,788,000
IDC NI	1,821,000	1,849,000
IDC RoI	1,727,000	1,781,000
Construction Insurance	805,000	805,000

4.3.7. Fuel Working capital (initial)[3]

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[4].

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 €2.7m, based on a requirement to run for 72 hours full load and an oil price of US$65/barrel. On an ongoing basis there will also be an opportunity cost to holding the fuel - see Section 4.4.6 below.

Table 4.6: Financing, interest and insurance costs

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Fuel working capital	2,665,000	2,665,000

4.3.8. Other non-EPC costs

The purpose for altering the presentation of non-EPC costs from previous years 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 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.

[3] Please note that working capital costs are not included in Table 4.16 below and are shown as a separate line item in Table 7.2 in the final section of the document. This reflects the chosen modelling approach.
[4] Secondary Fuel Obligations on Licensed Generation Capacity in the Republic of Ireland

From this benchmarking exercise, the percentage of EPC cost allocated to Other non-EPC costs is 9.0%. This amounts to €8,046,000 for the distillate option and €8,048,000 for the dual fuel option.

Table 4.7: Other non-EPC costs

Fuel Type	% of EPC	Other non-EPC costs
Dual Fuel	9.0%	€8,048,000
Distillate	9.0%.	€8,046,000

4.3.9. Market accession and participation fees

Parties will also need to pay market accession and participation fees before beginning operating. These costs are shown in the table below.

Table 4.8: 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	€1,500	€1,500
Participation Fee	The fee payable with an application to register and become a Participant in respect of any Unit	€3,500	€3,500

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[5].

For the purposes of this analysis, the TUoS charges and market operator charges are relevant.

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

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 4.9: Relevant network charges

Type of charge	Basis for calculation	Charge amount	Total Cost
Fixed market operator tariffs for Generator units	5% of costs recovered via fixed relative to variable charge. Flat per MW charge	€127/MW	Distillate - €24,130 Dual - €24,574.50

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.

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

- In NI, Transmission Use of System (TUoS) charges are designed to recover the NIE Transmission Revenue Entitlement as approved by NIAUR. The Transmission Revenue Entitlement is calculated as a percentage of NIE's Transmission and Distribution Entitlement which includes costs such as return on assets, depreciation of assets and operating expenditure. Currently 75% of the Transmission Revenue Entitlement is recovered from Suppliers and the remaining 25% of the Transmission Revenue Entitlement is recovered from Generators through the Generator export charge. Charges are available from SONI's charging statement[6]. For the period 1 October 2008 to 30 September 2009, the charge was £304.03/MW per month. We propose to use this figure, converted at an exchange rate of 1.12, 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[7]. Generation Network Location-Based Capacity Charges vary between €0.54/kW/annum and €10.57/kW/annum[8]. 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 €5.55/kW/annum, representing a midpoint of this range.

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

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[6] http://www.niaur.gov.uk/uploads/publications/SONI_Statement_of_charges_010908.pdf

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

[8] See http://www.eirgrid.com/media/Updated%202007-2008%20Statement%20of%20Charges%20v1.3%20–%20CER%20approved.pdf

Table 4.10: TUoS charges

Location	Fuel Type	TUoS charge (€)
NI	Distillate	776,779
	Dual Fuel	791,081
RoI	Distillate	1,055,055
	Dual Fuel	1,074,480

Loss factors

Losses are incurred on the transmission system as electricity is transported from generators to the transmission/distribution interface. In settlement, the transmission losses are allocated to generators using locationally varying transmission loss adjustment factors (TLAFs). As in previous years we make the assumption that the BNE plant will have a TLAF of 1.

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 interruptable products available in NI. An assumption therefore needs to be made on the approach that a rational investor would take to contracting for gas capacity.

While one could argue that it would be rational for a peaker with a very low load factor to only buy very short-term products, this would create a risk that capacity was not available during the periods when the BNE plant was required to run. As the plant would be serving the final MW, it would appear likely that all other plants would be running when the peaker was operating and that gas demand more generally would be high, increasing this risk. Hence we consider that the BNE plant would buy an annual strip of gas exit capacity. Our assumptions are as follows:

- In the RoI a party which wishes to take gas at a Transmission connected offtake point will need to hold Exit Capacity at that offtake point. The capacity charge is levied in respect of the Peak Day consumption requirement of the exit point. The Commodity element is applied in respect of each kilowatt of gas that is supplied through the system. For 2008/09 the peak day charge for use of the onshore network was €0.396360/kWh[9].

- In NI a postalisation tariff consists of a capacity and commodity charge that applies for use of transmission network system. The tariff calculation is based on the allowable revenue, as agreed with the NIAUR, and forecast demands[10]. For 2008/09 the capacity charge was £0.32544/kWh

[9] See http://www.gaslink.ie/files/about/20081001044912_Transmission%20Tariff%20for%20Gas%20Ye.pdf

[10] See http://www.bordgais.ie/networks/index.jsp?1nID=102&2nID=109&pID=311&nID=319

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.

Table 4.11: Gas transmission charges

Jurisdiction	Cost per kWh of peak day capacity	Plant Size (MW)	Efficiency (%)	Assumed hours run	Transmission Charge
NI	£0.32544/kWh	193.6	34.91	4 hours per peak day	€808,545
RoI	€0.396360/kWh	193.6	34.91	4 hours per peak day	€879,235

4.4.3. Operation and maintenance costs

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 €452,000 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 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 4.12: Fixed operation and maintenance costs

Fuel Type	O&M cost estimate
Distillate	€1,782,000
Dual Fuel	€1,807,000

4.4.4. Insurance

Our insurance estimate is based on a percentage of EPC costs and is based on past experience.

Table 4.13: Insurance costs

Fuel Type	Percentage of EPC	Total Cost

Distillate	1.6%	€1,430,000
Dual Fuel	1.6%	€1,431,000

4.4.5. Business Rates

We have followed the same approach used in previous year's consultations for calculating business rates.

Table 4.14: Annual business rates

	NI (€)	RoI (€)
Distillate	575,927	1,488,523
Dual Fuel	586,530.6	1,515,929

4.4.6. Fuel working capital (ongoing)

For each year which fuel is held there will be an opportunity cost. This cost is calculated as the initial cost of the fuel held (€2.7m) multiplied by the WACC assumed for modelling purposes. As the WACC differs slightly for each jurisdiction, the working capital figure will vary for each jurisdiction, as shown in Table 4.15 below.

Table 4.15: Fuel working capital costs

Fuel Working Capital cost estimate NI	Fuel Working Capital cost estimate RoI
€190,000	€181,000

4.5. Summary

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

Table 4.16: Investment Cost estimates (€ - rounded to nearest thousand)

Cost Item	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
EPC Costs	89,421,000	89,397,000	89,421,000	89,397,000
Site Procurement	1,527,000	1,527,000	1,425,000	1,425,000
Electrical connection Costs	5,676,000	5,676,000	7,400,000	7,400,000
Gas connection	3,380,000	-	1,690,000	-

Water connection	400,000	400,000	-	-
Owners Contingency	4,650,000	4,649,000	4,650,000	4,649,000
Financing Costs	1,788,000	1,788,000	1,788,000	1,788,000
Interest During Construction	1,781,000	1,727,000	1,849,000	1,821,000
Construction Insurance	805,000	805,000	805,000	805,000
Other non EPC Costs	8,048,000	8,046,000	8,048,000	8,046,000
Accession & Participation Fees	5,000	5,000	5,000	5,000
Total	**117,481,000**	**114,020,000**	**117,081,000**	**115,336,000**

Table 4.17: Recurring cost estimates (€ - rounded to nearest thousand)

Cost Item	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
Transmission & Market operator charges	1,099,000	1,079,000	816,000	801,000
Gas Transmission Charges	879,000	0	809,000	0
Operation and maintenance costs	1,807,000	1,782,000	1,807,000	1,782,000
Insurance	1,431,000	1,430,000	1,431,000	1,430,000
Business Rates	1,516,000	1,489,000	587,000	576,000
Fuel working capital	181,000	181,000	190,000	190,000
Total	**6,913,000**	**5,961,000**	**5,639,000**	**4,779,000**

4.6. Conclusion

These figures demonstrate that the distillate option is clearly cheaper that the dual fuelled options irrespective of location. We now go on to consider the other costs associated with locating this plant in NI or the RoI.

Text Box 4.1: Key findings for BNE cost estimates

Key recommendations:

- The BNE plant should be distillate fired.

5. ECONOMIC AND FINANCIAL PARAMETERS

This section outlines our consideration of the economic and financial parameters applying to the BNE plant. Analysis is summarised here and more detailed supporting information is provided in Annex 3.

5.1. Approach

In order to derive the BNE Peaker Cost, assumptions are required as to the Weighted Average Cost of Capital (WACC) for the investment in the BNE. Although a broad range of academic and market evidence exists on the cost of capital for utilities, both in Ireland and the UK, the RA's 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 the setting the cost of capital for the BNE given the uncertainty and volatility observed in financial markets since the start of the current 'credit crunch'.

In order to address these factors, we make use of traditional finance theory and cross check this against market evidence. For example, in estimating the real cost of debt we make use of evidence from new issues by Irish and UK utilities. We have also held discussions with banking contacts on the financing costs of similar types of investment in the UK and Ireland as a further cross-check.

5.1.1. Building blocks of a BNE cost of capital

In line with the majority of regulatory agencies in Ireland 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 approach to allowing 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. 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 2010. 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:

- **Type of investor** - we assume that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level for the peaking plant investment project in the forthcoming year. We do not think it realistic to assume, in the current financial markets, that debt would be raised at the project level.
- **Plant life** - the economic life of the project has been taken as 20 years, whereas previously 15 years was used. There has been a trend for CCGT plants to be economically evaluated over 30 years and even 35 years as opposed to the historical 25 years. Similarly, a trend for the economic life of peaking SCGT is moving from 15 years to 20 years.[11] In our discussions with the RAs, the RAs suggested that a life of 25 years might be appropriate, but on balance we think a 20 year plant life assumption prudent.
- **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[12]. This is because a sub-investment grade entity would not be competitive for this type of project and indeed may struggle to raise the necessary funding.

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 a BNE is inevitably a judgment. On the basis of the evidence presented in Annex 3 and regulatory precedent, we believe that a reasonable estimate for the gearing of the BNE is 60% as employed by the RAs for

[11] The base-load lifetime of the compressor sections of the GTs is approximately 15 years, but in light of the very low anticipated utilisation factor of the peaking plant, this does not pose a limitation. With all options including water injection capability and the ability for dual fuel retrofit if necessary, emissions compliance and fuel security issues into the future are unlikely. Furthermore, it is assumed that within Ireland prudent maintenance regimes would be undertaken such that plant operating life is maximised. Hence a move to a 20 year economic life was deemed more applicable for this study.

[12] Standard and Poors.

2009. In light of recent market uncertainty and volatility, we would not recommend an increase from 60%.

5.2.2. Cost of debt

A judgement of the appropriate range for the cost of debt depends on the assumptions of the BNE credit rating and debt maturity structure. We have considered evidence on the risk free rate (looking at both indexed-linked and nominal gilts) and the debt premium in the UK, Ireland and Europe for various credit ratings and debt maturity structures. We have also considered the costs of recent issues by investment grade utilities in the UK and Ireland.

On the basis of the evidence presented in Annex 3, our estimate of the appropriate range for the BNE cost of debt is 4.50% – 6.25% in the RoI and 4.00% - 5.50% in the UK.

5.2.3. Cost of equity

As we note above, we have employed CAPM as the primary tool for estimating the BNE peaking plant's cost of equity. We also cross-checked the CAPM derived cost of equity with recent regulatory precedent.

Our judgement of the appropriate range for the cost of equity for the BNE peaking plant is 6.90% - 8.75% in the RoI and 6.90% - 8.50% in the UK.

5.2.4. Taxation

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.

5.2.5. WACC

Our judgement of the appropriate range for the real pre-tax WACC for the BNE peaking plant is 5.85% - 7.75% in the RoI and 6.25% - 8.00% in the UK.

Text box 5.1: Key findings on BNE economic and financial parameters

Key recommendations.

- Electricity utilities in the UK and Republic of Ireland have sustained gearing levels broadly in the range 40 – 70%.
- On the basis of market evidence and regulatory precedent, we believe that a reasonable estimate for the gearing of the BNE is 60% as employed by the RAs for 2009.
- We have assumed that the plant life for the BNE will be 20 years. The broad expectation is 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.
- We have considered evidence on the risk free rate (looking at both indexed-linked and nominal gilts) and the debt premium in the UK, Ireland and Europe, for various credit ratings and debt maturity structures.

- Our estimate of the appropriate range for the BNE cost of debt is 4.50% - 6.25% in the RoI and 4.00% - 5.50% in the UK.
- We have employed CAPM as the primary tool for estimating the BNE peaking plant's cost of equity, cross-checked to recent regulatory precedent and market evidence.
- Our judgement of the appropriate range for the cost of equity for the BNE peaking plant is 6.90% - 8.75% in the RoI and 6.90% - 8.50% in the UK.
- 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.

6. Infra-marginal rent & Ancillary service revenues

In previous sections we identified the following:

- The Alstom 13E2 is the chosen GT.
- That plant should be distillate fired.

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

Modelling was carried out by the RAs using the PLEXOS model. The PLEXOS model is an optimisation based, simulation model used for developing system costs and market prices for energy and reserve. The Plexos model determined 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;
- Reward for Fast Start Capability;
- Provision of Spinning Reserve; and
- Provision of Leading/Lagging Power Factors.

Since the black start capability requires extra investment we have ruled it out as it as 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 spinning 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, shut down costs for a gas turbine. The only AS which therefore appears relevant is the provision of fast start capability. 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 have discussed estimates of AS revenues, including how these might change with proposals to harmonise the treatment of AS on an all-island basis, with the TSOs. The TSOs provided us with indicative assessments of AS revenues for the chosen BNE plant. This estimate does not vary depending on location. The estimate of these revenues is shown in Table 6.1 below.

Table 6.1: Annual ancillary services revenues

Fuel Choice	Ancillary Services Revenues
Distillate	€960,000/annum

Hence this is a revenue per kW per annum of €5.05

6.3. Conclusion

Table 6.2: Summary of infra-marginal rent and ancillary services revenues

Fuel Type	Infra-marginal rent	Annual Ancillary Services Revenues	Total
Distillate	0	€960,000/annum €5.05/kW/annum	€960,000 €5.05/kW/annum

Text box 6.1: Key findings on BNE infra-marginal rent and ancillary services revenues

Key findings:

- The plant would not earn any infra-marginal rent.
- It could expect to yield €960,000/annum (€5.05/kW/annum) in ancillary service revenues.

7. PROPOSED BEST NEW ENTRANT PRICE

Based on the discussions in the previous sections of this document, we now provide our 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. Approach & key assumptions

Our approach has been based upon the previous BNE calculation methodology with the changes in assumptions (from previous studies) noted below. This methodology calculates a levelised capacity cost by annuitizing the capital elements, using the pre-tax WACC for each region (as the investor will need to pay the statutory tax), to obtain an annual capital charge and then adding the annual fixed cost to these elements.

7.1.1. Economic life of the BNE plant

CEPA/PB consider that the appropriate economic life (we assume the plant life to be longer than twenty years as discussed previously) of the BNE plant is twenty years. CEPA/PB note that this is a change from the assumption used in the determination of past BNE prices. We consider this assumption to be valid because:

- In our collective experience, 20 years is a standard time horizon considered by equity investors. PB has (confidential) project experience of an economic life of 20 years being used for peaking GTs in the UK.
- In riskier markets than the SEM where investments will be backed by long-term Power Purchase Agreements (PPAs), twenty years tends to represent a minimum norm.
- Equity investors tend to be willing to accept long term returns from relatively low risk assets and banks will tend to supply debt with a 'door to door' life of between 13 years and 20 years (they will always want to be paid out before equity). This debt tenor was confirmed to us during discussions with **a** UK bank as part of the process of developing this document. The bank did not provide evidence of recent market turbulence having altered its position.
- Equity investors into power generation tend to be willing to take a longer term investment horizon in the knowledge that a longer 'payback' period for debt and equity will make their plant lower cost in terms of annual fixed payments. A plant with say a 10 year payback period would be far less competitive in the market than one with a longer investment horizon

7.1.2. 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 modelling assumptions

Assumption	Justification
Euro to Sterling exchange rate is 1.12 Euros to the pound.	Spot rate at time of developing document. Spot rate viewed as best indicator of future rate.
Midpoints of ranges for cost of capital have been used.	CEPA/PB have recommended ranges, the midpoint is used for ease but does not necessarily represent our view on the point estimate of the cost of capital.
Residual value of land and fuel included by present valuing of end term values	These items will have a real value that can be realised in the market
No residual value for plant	Plant life is assumed to be 20 years
IDC	Based on quarterly drawdown at pre tax WACC
Initial Working Capital	Initial fuel charge plus one month's receivables
Owner's contingency	Included, although could be considered as a part rolled up into the WACC
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 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 **€80.11/kW/yr.**
- In the RoI **€84.12/kW/yr.**

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	€'000	114,019	115,335
Land and Fuel Residual Value	€'000	-1,120	-1,030
Initial Working Capital	€'000	5,560	5,370
Total Annual Costs	€'000	5,961	4,779
Plant Size	MW	190.1	190.1
Pre Tax Weighted Average Cost of Capital	%	6.80	7.13
Plant Life	Years	20	20

Annualised Costs	€'000	16,950	16,190
Deductions			
Inframarginal Rent	€'000/annum	0	0
Ancillary Service revenues	€'000/annum	960	960
Final BNE cost	**€/kW**	**84.25**	**80.11**

We therefore conclude that the plant should be distillate fired and located at the Belfast West site in NI.

ANNEX 1: CEPA/PB LONG-LIST OF TECHNOLOGY OPTIONS

The table below sets out a long-list of options for the BNE, capturing all available technology options which might reasonably be described as a peaking plant (with unit capacities between 35 and 200MW). The ISO power output per machine is for operation without water injection.

2010 BNE Peaking Plant - Selection Criteria Flowchart

Initital Considerations of 50 Hz Technology Options between 35MW 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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo# V64.3A	GE 6581B	GE 6591C	GE 6111FA	GE 9171E	GE 9231EC	GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	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)	MAN 12 K90MC-S	Alstom GT26 with LLOC†
Type	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	Engine	CCGT
ISO output per machine	56.5 MW	113.6 MW	180.2 MW	75.0 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	98.5 MW	50.3 MW	55.4 MW	52.7 MW	60.5 MW	47.0 MW	49.5 MW	67.4 MW	167.7 MW	190.8 MW	50.2 MW	~425 MW

\# The Ansalso V94.2 is so similar to the Siemens SGT5-2000E that it is not considered.

† Though the CCGT unit is larger than 200MW and so excluded, it has been shown to highlight the LLOC (Low Load Operation Concept), which enables the CCGT to "park" at 20% load, maintaining emissions compliance, and ramp up to 100% load in 12 minutes.

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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	GE 6581B	GE 6591C	GE 6111FA	GE 9171E	GE 9231EC	GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	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)	MAN 12 K90MC-S	

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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	GE 6581B		GE 6111FA	GE 9171E		GE LM6000PC	GE LM6000PC Sprint	GE LM6000PG	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)		MAN 12 K90MC-S	

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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	GE 6581B		GE 6111FA*	GE 9171E		GE LM6000PC	GE LM6000PC Sprint			P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry		Siemens SGT-800			Siemens SGT5-2000E (33 MAC)		MAN 12 K90MC-S	

* 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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo V64.3A	GE 6581B			GE 9171E		GE LM6000PC	GE LM6000PC Sprint			P&W FT8 Swift Pac 60 (dry)^	P&W FT8 Swift Pac 60 (wet)	RR Trent 60 Dry		Siemens SGT-800			Siemens SGT5-2000E (33 MAC)		MAN 12 K90MC-S	

^ 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
Option	Alstom GT8C2	Alstom GT11N2	Alstom GT13E2	Ansaldo# V64.3A	GE 6581B			GE 9171E		GE LM6000PC	GE LM6000PC Sprint		GE LMS100 PA	P&W FT8 Swift Pac 60 (dry)	P&W FT8 Swift Pac 60 (wet)			Siemens SGT-800			Siemens SGT5-2000E (33 MAC)		MAN† 12 K90MC-S	
ISO efficiency	33.9	33.3	36.9	35.9	32.1			33.8		40.1	40.2		43.9		37			37.5			34.7		48.4	
GTW equipment USD/kW	339	265	241	369	359			260		327	303		330		334			357			243		398	
Short List*			Alstom GT13E2								GE LM6000PC Sprint				P&W FT8 Swift Pac 60 (wet)						Siemens SGT5-2000E (33 MAC)			

\# From GT PRO

† From supplier

ANNEX 2: THE IMPACT OF WATER INJECTION ON GT PERFORMANCE

Water injection into the combustion chamber of a gas turbine is typically carried out for one or both of these purposes: the reduction of the production of oxides of Nitrogen that form during combustion and the increase in power output of the gas turbine. The purpose of this document is not to consider the impact of water injection on NOx production but to justify its impact on power augmentation, with specific reference to the Siemens SGT5-2000E and the Alstom GT13E2 gas turbines.

The physical effect of injecting water into the combustion chamber of a gas turbine is to reduce the temperature of the combustion gases. As gas turbines are typically controlled to maintain a constant turbine inlet temperature, the effect of water injection is to cause more fuel to be admitted into the combustion chamber such that the turbine inlet temperature is maintained. The increase in fuel and water flow rates causes an increase in mass flow rate through the power turbine, resulting in increased power output. The combustion products that contain a higher proportion of water vapour when water injection is employed, do have a greater heat transfer coefficient such that metal temperatures on the turbine blades may become hotter. As a result, certain GTs have the ability to employ what is called "dry control", which is a reduction in turbine inlet temperature such that turbine metal temperatures are maintained. This reduction in turbine inlet temperature causes a reduction in power output; however, the power output with dry control remains higher than if no water injection was employed. By way of example, in the General Electric document, GER-3620k, the impact of 3% steam injection on the 7E gas turbine is a 10% increase in power output and with dry control, it is an 8% increase.

For the GT13E2, Alstom claim that almost 10% power augmentation is achievable by water injection. In modelling the GT13E2 in GT PRO/MASTER at European winter conditions on distillate, the gross power output without water injection is 185.0 MW. With a 1:1 water to fuel ratio (mass basis), which is the approximate level of water injection required to achieve 120mg/Nm3, the gross power output increases to 197.8 MW, a 6.9% increase.

For the Siemens SGT5-2000E, the built-in GT PRO model has a limitation on the power output of the SGT5-2000E that results in water injection appearing not to increase the power output. This limitation does not exist in reality and through two different requests to Siemens (including the use of the Siemens Plant Performance Estimation Program Version 3.3.1), the increase in power output resulting from water injection has been confirmed. At an ambient temperature of 9°C, an approximate 3.3% power increase is obtained when a water to fuel ratio (mass basis) of 1:1 to 1.25:1 is employed.

ANNEX 3: COST OF CAPITAL FOR A BEST NEW ENTRANT PLANT

A1.1 Overview

This appendix 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 2010. 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.

A1.2 Summary of previous year determination

In the previous year's cost of capital determination, the RAs derived 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). The table below sets out the individual parameters that the RA's proposed in the Consultation Paper and the point estimates which were used in the final decision. The key points to note from the decision are as follows:

- The RA's used a gearing assumption of 60% as opposed to the 70% gearing proposed in the consultation.
- The RA's used a real cost of debt of 4.36% for the Republic of Ireland and 4.76% for the UK. This was derived on the basis of a BNE credit rating of BBB using corporate bond data from the UK, Europe and the US.
- The real pre-tax cost of equity for a BNE plant was estimated as 9.74% for the Republic of Ireland and 9.38% for the UK. This was based on an equity risk premium (ERP) of 5.5% and an asset beta for the BNE of 0.6.
- 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% and 28.0% was used for the Republic of Ireland and the UK respectively).

These individual parameters resulted in a real pre-tax WACC of 7.07% for the RoI and 8.07% for the UK.

Table A1: WACC estimate for BNE peaking plant in 2009

	Consultation		Decision	
	RoI	**UK**	**RoI**	**UK**
Nominal RfR	4.58%	4.82%	4.56%	4.97%
Inflation	2.40%	2.40%	2.40%	2.40%
Real RfR	2.13%	2.36%	2.11%	2.51%
Debt Risk Premium	2.25%	2.25%	2.25%	2.25%
Real Cost of Debt	**4.38%**	**4.61%**	**4.36%**	**4.76%**
Real RfR	2.13%	2.36%	2.11%	2.51%
Market rate of return	7.63%	7.86%	7.61%	8.01%
Tax rate	12.50%	28.00%	12.50%	28.00%
Asset beta	0.60	0.60	0.60	0.60
Equity beta	1.83	1.61	1.39	1.25
Cost of equity	**12.17%**	**11.21%**	**9.74%**	**9.38%**
Gearing	70%	70%	60%	60%
WACC, real Pre Tax	**7.24%**	**7.90%**	**7.07%**	**8.07%**

Source: NIAUR ; CER

We believe that a number of alternative and additional pieces of evidence should be considered in developing an appropriate range for the allowed WACC. These are discussed in more detail in the approach section which follows.

A1.3 Approach

This report approaches the estimation of the WACC for a BNE peaking plant through consideration of two separate sources of information:

- a calculation of the BNE WACC based on a bottom up approach; and
- previous regulatory decisions in the UK and the RoI.

Although a broad range of academic and market evidence exists on the cost of capital for utilities, both in Ireland and the UK, the RA's 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 the setting the cost of capital for the BNE given the uncertainty and volatility observed in financial markets since the start of the current 'credit crunch'.

In order to address these factors, we make use of traditional finance theory and cross check this against market evidence. For example, in estimating the CoD we make use of evidence from new issues by Irish and UK utilities. We have also held discussions with our banking contacts on the financing costs of similar types of investment in the UK and Ireland as a further cross-check.

A1.4 Gearing

In theory, the optimal level of gearing is that level of gearing at which the marginal interest tax shield benefit (arising from tax allowance) equates to the marginal default risk cost. However in practice, regulators when determining the allowed WACC for regulated assets, 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 have adopted a similar approach for developing an assumption of the gearing of the BNE peaking plant. In this section, we develop an assumption for the 'notional' level of gearing of the BNE based on market evidence of comparable businesses in the UK and Ireland and precedent in regulated utility sectors.

We have assumed that the BNE would be funded as part of an integrated utility rather than on a standalone non-recourse project finance basis. Additionally, it has been assumed that the gearing level is consistent with an investment grade rating, ie 'BBB' or above using Standard & Poor's nomenclature.

A1.4.1 Regulatory precedent

Table A2 shows recent relevant gearing assumptions adopted by regulators to calculate the WACC.

Table A2: Gearing regulatory precedent

Regulator	Decision	Gearing assumption
Republic of Ireland		
CER / NIAUR	BNE (2008)	60%
CER	Gas Review (2007)	55%
CER	Electricity (2005)	50%
United Kingdom		
CAA (CC)	Heathrow/Gatwick Airports (2008)	60%
Ofgem	Gas Distribution (2007)	62.5%
Ofgem TPCR	Transmission (2006)	60%
Ofgem DPCR	Electricity Distribution (2004)	57.5%
Ofwat	Water (2004)	55%

A1.4.2 Market evidence

In order to inform a judgment about an appropriate assumed gearing for the BNE, Table A3 shows the level of gearing for a range of comparable companies currently active in the Irish and UK energy sectors.

Table A3: Market evidence of electricity utility gearing assumptions

Company	Gearing	Credit rating
AES Corp	72%	BB-
Bord Gais	53%	A
Bord na Mona	33%	n/a
Centrica	44%	A
Endesa	48%	A
ESB	35%	n/a
International Power	64%	BB-
EON	52%	A
Scottish Power	42%	A-
Scottish & Southern Energy	65%	A
Viridian	65%	n/a

Source: Company Annual Reports; Bloomberg & CEPA

The points to note from Table A3 are as follows:

- Electricity utilities in the UK and Republic of Ireland have sustained gearing levels broadly in the range 40 – 70%.
- This 40 - 70% range for a utility asset gearing ratio is broadly consistent with an investment grade credit rating.

Identifying an appropriate gearing assumption for a BNE is inevitably a judgment. In our view, based on the above and discussions with the City, a notional gearing level of 60% is appropriate for determining an allowed WACC for power generation projects in both the UK and RoI. This is the same gearing level as used for the 2009 calendar year.

A1.5 Cost of debt

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

A1.5.1 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. The broad expectation is 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.

A1.6 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.

A1.6.1 Risk-free rate (United Kingdom)

Index-linked debt

A commonly used source for risk-free rate estimates is the redemption yield on government-issued index-linked gilts (ILGs). As set out in the UK Competition Commission's analysis of the cost of capital for the Stansted airport price control:

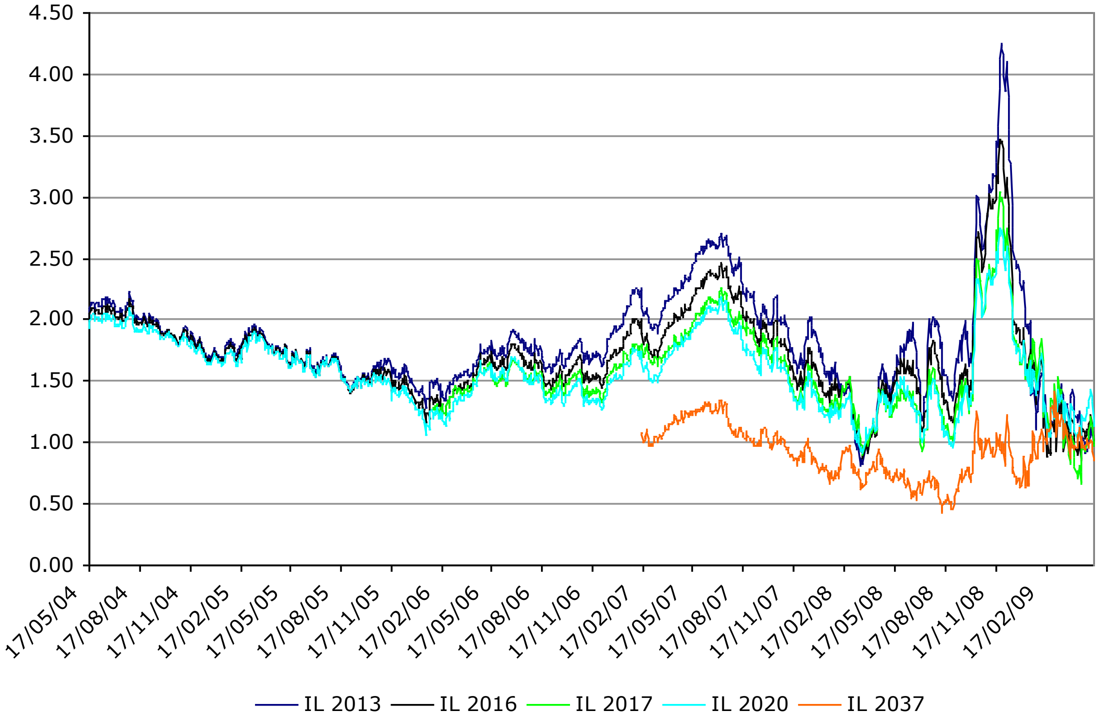
> "These are assets with negligible default risk and relatively insignificant inflation risk which are generally thought to give the best available indication of the return that investors would require in exchange for holding a truly risk-free asset."[13]

We do, however, note that a number of observers, including the Competition Commission, have noted that this market may in part be distorted, particularly for long-dated ILGs, by pension fund investor requirements. Our analysis on the risk-free rate for the UK takes account of these comments on the UK ILG market.

Figure A2 below shows recent movements in the yields on a selection of UK Government ILGs. It shows that the impact of increased market turbulence and a flight to quality has lead to quite dramatic reductions across all maturities. In the past six months, the yield curve for index-linked gilts has also flattened, whereas previously it was more downward sloping.

[13] Competition Commission, Stansted Airport Review 2008, Appendix L, p. L12.

Figure A2: Yields on index-linked gilts



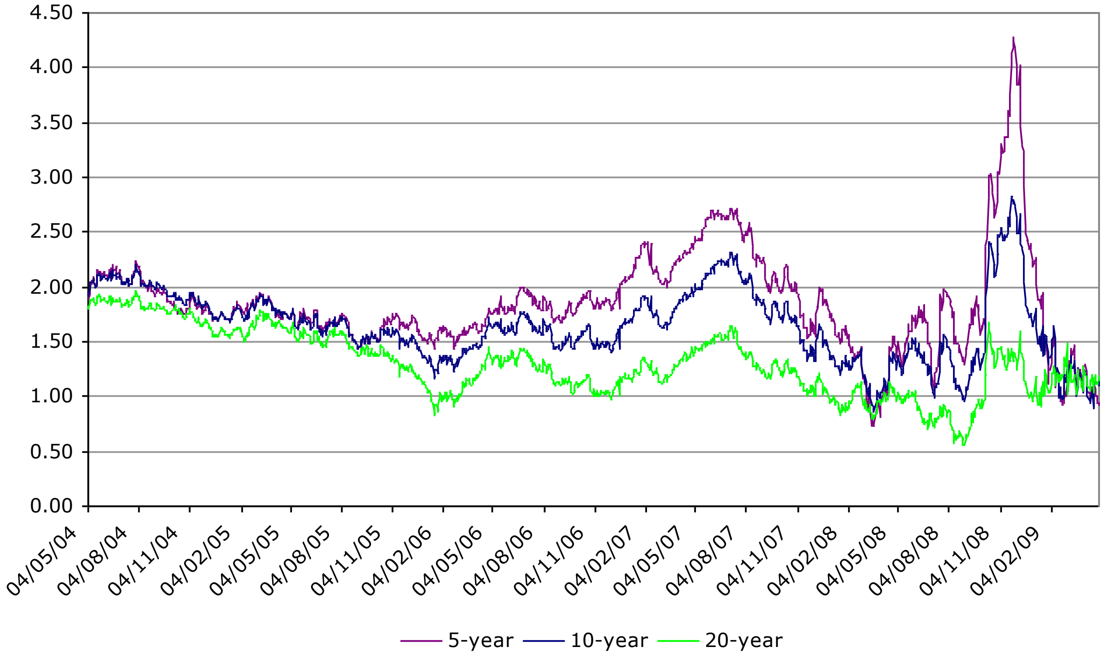
Source: UK Debt Management Office

Spot rates on 10 year ILG yields are currently approx 110bp which is below the 12 month trailing average of approximately 150bp.

Conventional gilts

Figure A3 below shows the movements in real yields on zero coupon bonds. The movements in yields mirror those seen in ILGs and show significant reductions across all maturities and a similar flattening of the yield curve.

Figure A3: Real yields UK zero coupon bonds



Source: BoE

Consistent with the market for ILGs, spot rates for 10 year debt are around 115bp with a 12 month trailing average of approx 150bp.

A.1.6.2 Risk-free rate (Republic of Ireland)

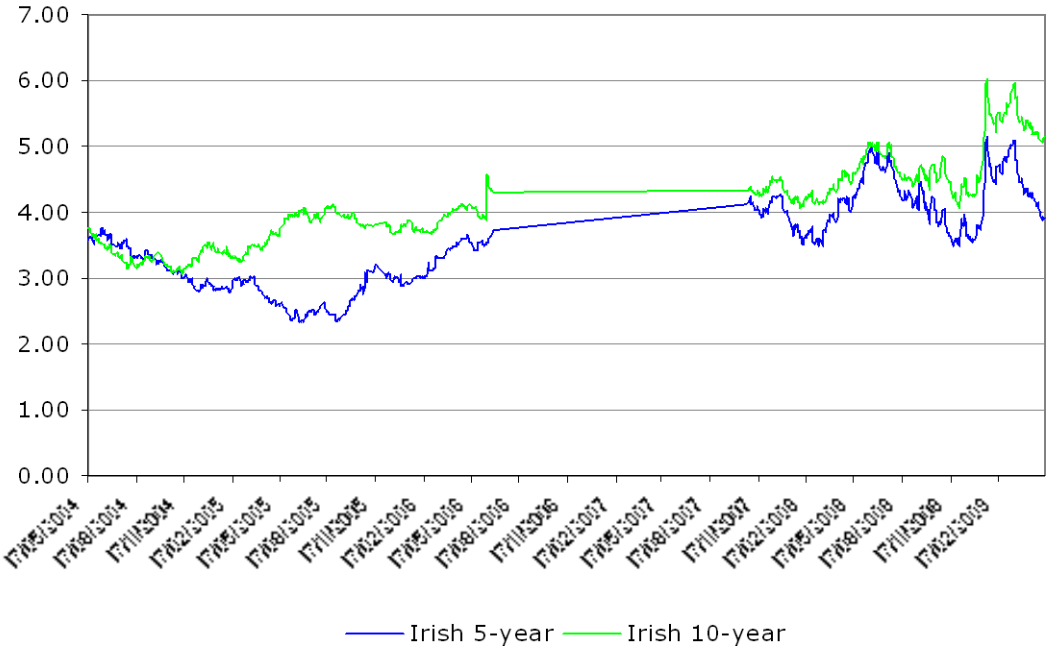
In the absence of Irish government issued ILGs, our methodology for estimating the real RfR for the RoI can be broadly characterised as:

- estimating the nominal RfR based on conventional Irish sovereign backed debt;
- estimating inflation for the Irish market;
- deflating the nominal RfR by the inflation estimate; and
- cross checking this against evidence from the wider Euro zone.

Conventional Irish sovereign debt

Figure A4 below, shows the nominal return on Irish gilts for the past 5 years[14].

Figure A4: Nominal yield on Irish benchmark gilts



Source: Bloomberg

For 10 year debt nominal spot rates are currently around the 515bp level which, whilst lower than the peak of the market turbulence, is still above the 12 month trailing average of 490bp. Also to note is that the slope of the implied yield curve has increased over the last 12 months.

Inflation expectations

We have based our inflation expectation on the European Central Bank's (ECB) longer term forecast of inflation[15]. We believe it is appropriate to use longer term estimates of inflation as the investment is in long lived assets and investors expect to earn their return over a long term period.

In light of this, and noting that inflation for the Republic of Ireland for the 12 months to April was recently reported as -3.5%, we believe it is appropriate to use an expected inflation estimate of 1.9%. This is the ECB's current longer term forecast of inflation for the Euro-zone.

Wider Euro zone evidence

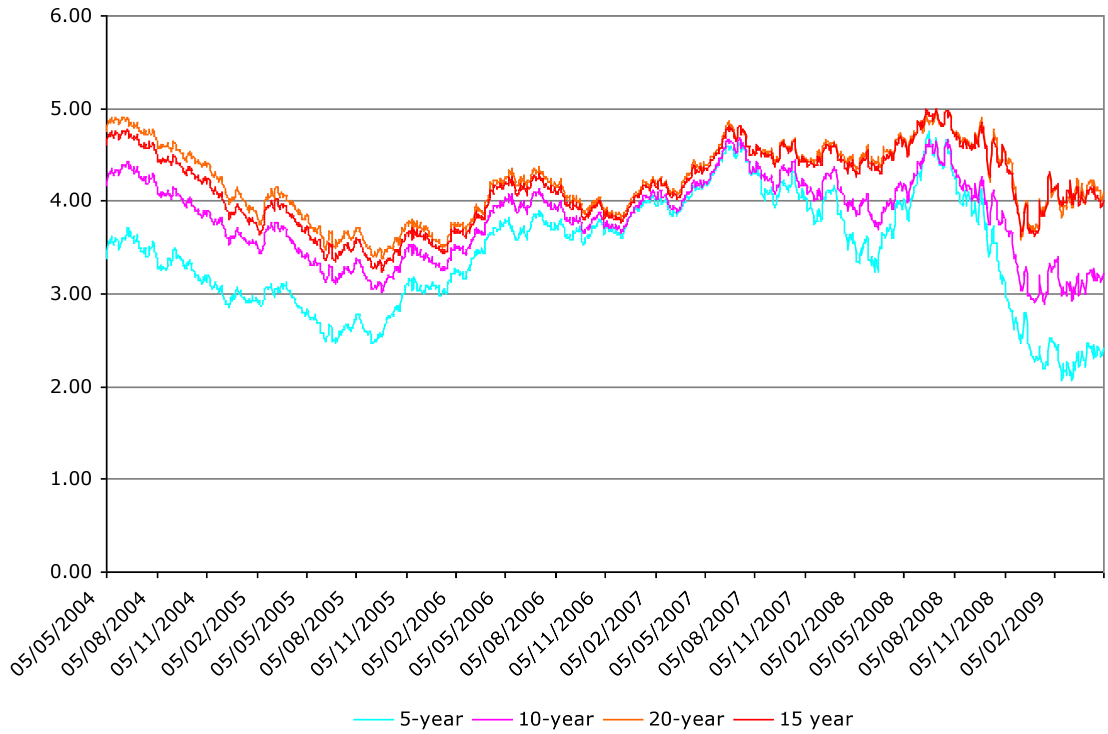
<u>Conventional Euro-zone sovereign debt</u>

[14] Note there is a break in the time series for both maturities for a period of 2006.

[15] See http://www.ecb.int/pub/pdf/mobu/mb200905en.pdf

Figure A6 below, shows the nominal return on benchmark Euro-zone government bonds for the past 5 years. The key points to note are the recent divergence of yields across maturities and the significant reductions in rates at the shorter (5 and 10 year) end of the yield curve.

Figure A6: Yield on Euro-zone benchmark gilts

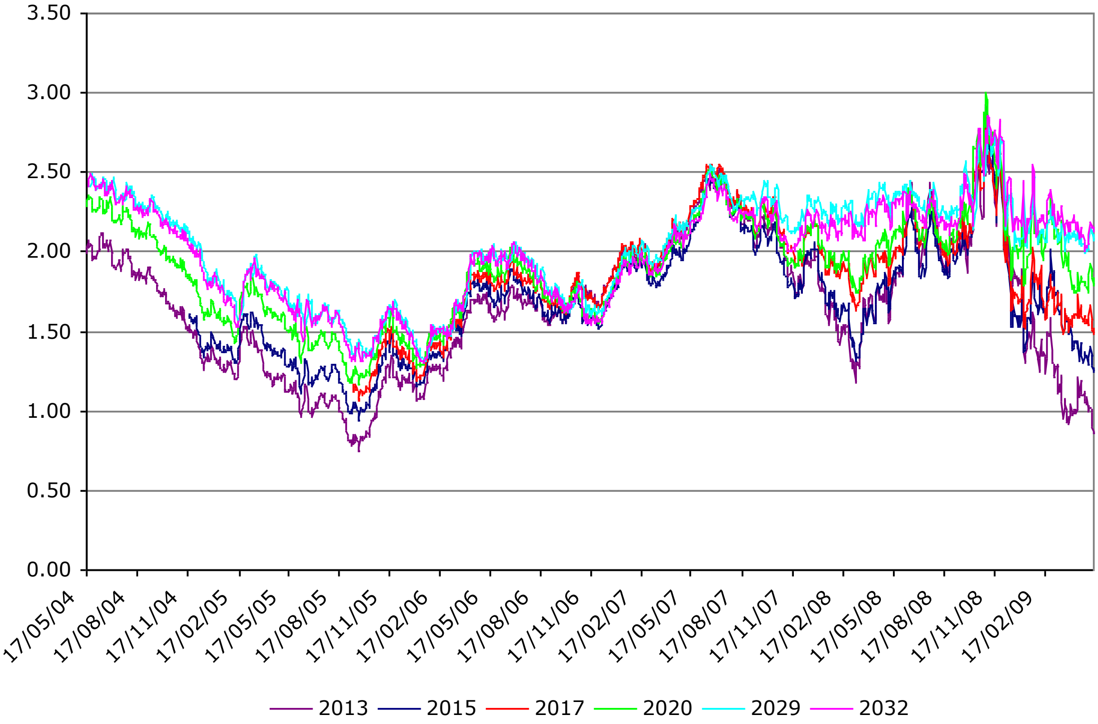


Source: Bloomberg

French index linked bonds

Whilst the Irish Government does not currently issue ILGs, index linked bonds backed by the French Government are available. Figure A5 shows the yields on a selection of French Government index-linked bonds. It illustrates that the movements in yields for French Government index-linked bonds mirror those on index-linked securities in the UK, with dramatic reductions in rates over the past 12 months across all maturities and an upward sloping yield curve.

Figure A5: Yields on French Government index-linked bonds



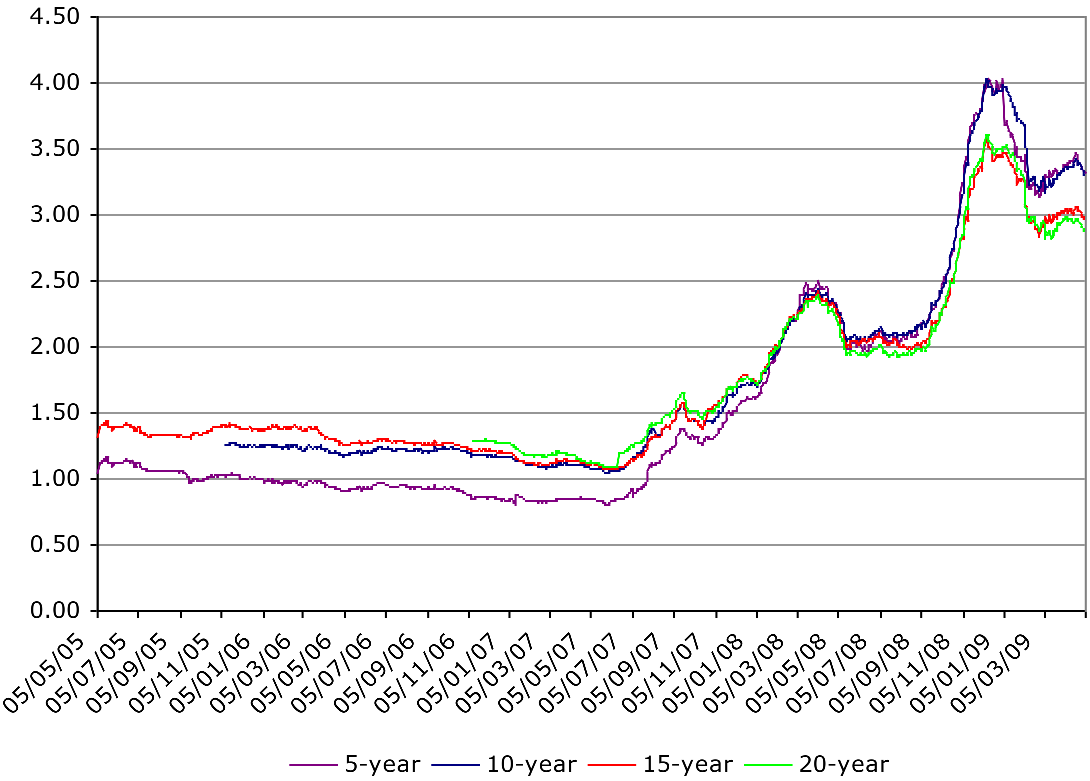
Source: Bloomberg

A1.6.3 Debt premia

United Kingdom

Figure A7 shows the evolution of spreads (against gilts) for sterling denominated corporate debt with a BBB rating for different debt maturities. It depicts a dramatic increase in the risk premium from September 2008 (following the collapse of Lehmann Brothers) but significant reductions across all maturities in the last six months.

Figure A7: Spreads on BBB rated UK corporate debt



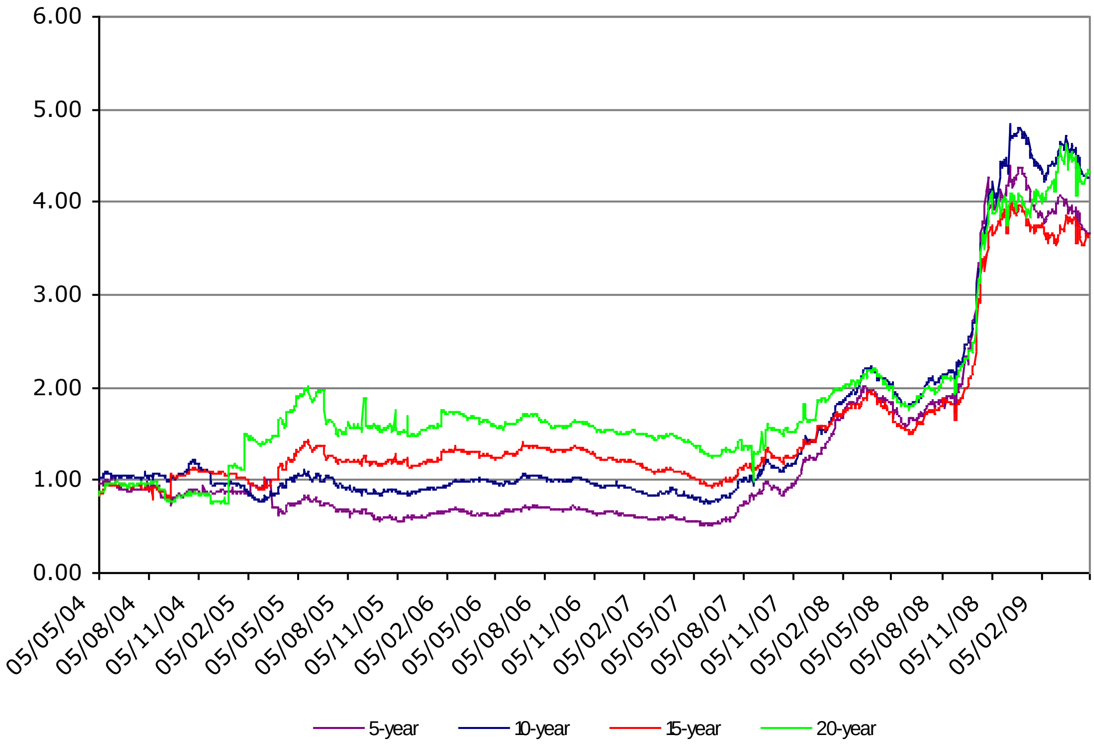
Source: Bloomberg

A key issue for estimating the debt premium for a BNE peaking plant (seeking to enter the SEM in 2010) is the extent to which the widening of spreads associated with the current market turbulence will be sustained. There is a question of whether there may be mean reversion over the coming months, if markets normalise, or whether rates will stabilise at a new level higher than prior to the beginning of the credit crunch.

Republic of Ireland

Figure A8 shows the evolution of spreads (against Euro-zone benchmark government bonds) for Euro denominated corporate debt with a BBB rating for different debt maturities. Similar to the evidence on spreads for sterling debt, it shows a dramatic increase in the risk premium from September 2008, but reductions across all maturities in recent months.

Figure A8: Spreads on BBB rated European corporate debt



Source: Bloomberg

A.1.6.4 Conclusions on components analysis

United Kingdom

The market evidence presented above suggests ranges for the UK cost of debt components of:

- 100 – 200bp for the real RfR; and
- 200 – 350bp for the debt premium.

The lower end of the RfR range is given by current spot rates whilst the upper end reflects trailing averages and recent volatility.

For the debt premium, the lower end of the range reflects trailing averages and scope for mean reversion whilst the upper end reflects current spot rates.

Republic of Ireland

The market evidence implies ranges for the RfR and debt premium for the RoI of:

- 150 – 300bp for the real RfR; and
- 300 – 450bp for the debt premium.

The lower end of the RfR range is given by market evidence from the wider Euro-zone whilst the upper end is based on deflated 10 year Irish sovereign debt.

The lower end of the debt premium range for the RoI factors in a small amount of mean reversion from today's levels whilst the upper end reflects the volatility in current spot rates.

A1.7 Wider evidence on the cost of debt

In this section we consider evidence from recent utility debt issues and regulatory precedent to refine the estimated ranges suggested by market data.

1.7.1 Recent utility company debt issues

Table A4 contains evidence on recent issues of utility company debt raised in the UK. It shows the coupons for each of the recent issues, as well as the current yield and spread to maturity / cost of debt.

Table A4: Recent utility debt issuance

Date	Issuer	Size	Maturity	Rating	Coupon	YTM	Spread
19/09/08	Centrica	£400m	2018	A-	7.00%	5.79%	224.2
09/12/08	Centrica	€750m	2013	A-	7.125%	4.73%	291.0
17/04/09	Centrica	£300m	2014	A-	5.125%	4.93%	230.7
20/11/08	SSE	£500m	2028	A	8.375%	6.37%	183.0
05/02/09	SSE	£700m	2014	A	5.75%	4.58%	183.0
22/01/09	Severn T	£400m	2018	A	6.00%	5.41%	232.4
13/01/09	NG Elect	£379m	2031	A-	7.375	6.38%	178.9
04/02/09	NG plc	£400m	2014	BBB+	6.125%	5.41%	280.6
22/01/09	NG plc	€578m	2014	BBB+	6.50%	5.26%	253.7
29/12/08	UU	£375m	2015	A-	6.125%	5.00%	197.2
25/03/09	UU	£275m	2022	A-	5.75%	5.93%	206.6

Source: Bloomberg

The key points to note from the table are:

- UK utilities with credit ratings ranging from BBB+ to A have been able to issue conventional debt at coupons ranging from 6.1% to 8.4% since September last year.
- A number of large integrated utilities in the energy sector (Centrica and SSE) have issued debt in the early part of 2009 at significantly discounted rates to the debt they issued in the latter parts of 2008.
- Current yields to maturity for all the recent utility issues reported are at a significant discount to coupon rates and current spreads to gilt range from 180 to 200 basis points.

A1.7.2 Regulatory precedent

Table A5 below shows recent decisions taken by regulators in the UK and Ireland on the cost of debt.

Table A5: Recent UK regulatory decisions on the cost of debt[16]

Regulator	Decision	Rf	Debt Premium	CoD Used
United Kingdom				
CAA/CC	BAA Heathrow (2008)			3.55%
Ofgem	GDPCR (2007)	2.50%	1.3%	3.55%
Ofgem	TPCR (2006)	2.50%	1.25%	3.75%
Ofwat	Water & sewage (2004)	2.50-3.00%	0.80-1.40%	4.30%
Ofgem	DPCR (2005)	2.25-3.00%	1.00-1.80%	4.10%
Ireland				
CAR	Air Traffic Services	1.84%	0.38%	2.22%
CER	Gas (2007)	2.25%	1.20%	3.45%
CER	Electricity (2005)	2.38%	1.35%	3.73%
CAR	Airports (2005)	2.6%	1.1%	3.7%

[16] All regulatory decisions show the real cost of debt, accept Eircom which is the nominal allowed cost of debt.

A1.8 Conclusion on the cost of debt

Table A6 brings together our view on the cost of debt faced by a notional BNE peaking plant in the RoI and UK. In narrowing our ranges from the market data evidence on individual components, we have been guided by all in costs of debt being observed in the market and by regulatory precedent. The range for the UK and the RoI is broadly in line with 12 months ago, and reflects scope for mean reversion over the coming months for both the risk-free rate and the debt premium.

We therefore recommend that the appropriate cost of debt to allow a BNE peaking plant investment in the RoI for 2010 lies within the range 4.50% – 6.25% and for the UK in the range 4.00% – 5.50%.

Table A6: Summary range for BNE cost of debt

	RoI Low	RoI High	UK Low	UK High
Risk-free rate	1.50%	2.25%	1.50%	2.00%
Debt premium	3.00%	4.00%	2.50%	3.50%
Cost of debt	**4.50%**	**6.25%**	**4.00%**	**5.50%**

A1.9 Cost of equity

As discussed in Section A1.3 we have employed the capital asset pricing model (CAPM) as the primary tool for estimating a notional BNE peaking plant's cost of equity. We then cross-check the CAPM derived cost of equity against recent regulatory precedent.

The CAPM defined cost of equity equation is presented below:

$$CoE = r_f + \beta(ERP)$$

where $CoE =$ cost of equity

$r_f =$ risk free rate

$ERP =$ equity risk premium for the market portfolio

$\beta =$ measure of non-diversifiable risk of the security relative to the market portfolio

That is, according to CAPM the cost of BNE equity is fully specified by and requires the estimation of:

- the risk-free rate (described and estimated in Section A1.6 above);
- an equity risk premium; and
- an equity beta.

The first two of these variables are 'economy-wide' whilst the β is business specific. We use the same RfR from our assessment of the cost of debt and discuss the equity risk premium and beta below.

A1.9.1 Equity risk premium

The equity market risk premium (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 with many column inches in the literature given over to debating the relative merits of geometric means versus arithmetic means. Hence we have not attempted to come up with a different ERP for RoI and the UK.

Generally speaking, it is estimated by determining 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 a portfolio 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.

Table A7 below summarises a broad range of academic studies on total market returns and the ERP implied by these. These estimates were reported and commented upon by the UK Competition Commission in its analysis of the cost of capital during the 2008 review of Stansted Airport.

Table A7: UK market return/equity-risk premium estimates

	Rm	Rf	Rm-Rf
Ex post estimates, long –term historical data			
Dimson, Marsh, Staunton (2008) geometric averages	5.5	1.3	4.1
Dimson, Marsh, Staunton (2008) arithmetic averages	7.3	2.2	5.4
Smithers and co (2004; 2006)		2 – 2.5	
Ex ante estimates, long –term historical data			
Dimson, Marsh, Staunton (2008) geometric averages	4.0-4.5	1.0	3.0-3.5
Dimson, Marsh, Staunton (2008) arithmetic averages			4.5-5.0
Gregory (2007) geometric averages	5.4-6.8	2.2-3.0	3.3-3.8
Gregory (2007) arithmetic averages	5.9-7.8	2.3-2.9	4.4-5.3
Forward-looking residual income model recent historical data			
Claus and Thomas (2001)			3.4
Ex ante estimates using latest market data			
Gregory (2007) geometric averages	3.8-5.6	2.3	1.7-3.3
Gregory (2007) arithmetic averages	4.3-6.2	2.3	2.0-3.9
CC (2007), dividend growth model	4.6-5.8	2.5	2.1-3.3
CC 12 September 2008, dividend growth model	5.8-7.0	2.0	3.8-5.0

Source: Competition Commission & CEPA/PB

The table indicates that academic studies give a wide range for the UK ERP of 1.7% – 5.4%.

We have also considered regulatory precedent on the ERP. Recent UK and Irish regulatory assessments of the ERP area shown below in Table A8.

Table A8: Recent relevant decisions on the ERP

Case	Equity risk premium (%)
CER / NIAUR - BNE (2008)	5.50%
CAA / CC – BAA (2008)	2.5 – 4.5%
ComReg – Eircom (2008)	6.00%
CAR – Air Traffic Services (2007)	5.00%
CER – Gas (2007	5.00%
CAA – BAA (2006)	4.50%
Ofgem – NGET RO (2005)	4.75%
CER – ESB (2005)	5.25%

Source: CEPA

The table above shows that a range of 2.5 – 6.0% has been employed by regulators since 2005.

The intersection of the academic and regulatory ranges is given by 2.5 – 5.4%. In our view the bottom end of this range does not reflect current market conditions and believe that it is appropriate to employ a range for the ERP of 4.5 – 5.0%.

A1.9.2 Beta

A company's equity beta is a measure of the non-diversifiable risk attached to its equity. That is, 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 the co-variance between returns on the stock and returns on the market portfolio, over the variance of returns on the market portfolio. By definition, the market has a beta of 1.0.

Broadly speaking there are two approaches to determining a business' equity beta:

- rely on actual observed equity betas seen in the market; or
- estimate a delevered asset beta, that is, the operational risk of the underlying business assets, and apply a particular gearing level to take account of financing risk and calculate its equity beta.

The issue with the former is that, in the case of regulated assets, there are few standalone listed companies meaning the observed equity betas reflect wider risks faced by the company than just the risks faced by the regulated asset. Furthermore, as we are using a notional gearing level it would be inappropriate to rely wholly on observed equity beats as they reflect individual financing decisions. For these reasons we follow the second approach outlined above.

The key factors influencing the BNE peaking plant's asset betas include:

- It is exposed to price and volume risk. These may rise or fall due to systematic factors related to economic growth.
- The existence of the capacity payment mechanism means that generators are to a certain degree protected from general price and volume risks related to economic growth; against this however,
- high fixed costs of a BNE magnify the effect of underlying systematic (price and volume) risk.

Our qualitative assessment of the non-diversifiable operational systematic risk of a BNE peaking plant leads us to conclude that it is reasonable to assume an asset beta for the investment of around 0.5. We note that this is greater than the delevered asset betas for UK utilities of around 0.4 and in line with the implied asset betas for international airports of 0.5[17].

Relevering this for a 60% notional gearing level[18] gives an implied equity beta in the range of 1.2 – 1.3.

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[17] See http://www.caa.co.uk/docs/5/ergdocs/20090305AssetBeta.pdf

[18] The formula for this is $\beta_E = \beta_A/(1-g)$

A1.9.3 Conclusion on the cost of equity

Using our common estimates for UK and Ireland for the ERP and equity beta and the country specific risk free rates estimated as part of the cost of debt analysis above our estimated ranges for the cost of equity are presented in the table below.

Table A9: Summary range for BNE cost of equity

	RoI Low	RoI High	UK Low	UK High
Risk-free rate	1.50%	2.25%	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%**	**8.75%**	**6.90%**	**8.50%**

A1.10 Taxation

The cost of capital for the BNE in the previous year's determination was set on a real pre-tax basis. CEPA/PB is of the view that the WACC is not necessarily the most appropriate mechanism to allow for taxation costs and that there is merit in forecasting actual taxation costs and allowing for these through BNE costs estimation.

However, we recognise that given the RA's 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.

A1.11 Consortium estimate of BNE peaking plant cost of capital

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 estimates for the BNE peaking plant WACC are presented in the table below. This should be compared with real pre-tax WACC decision from the previous BNE WACC determination (also shown in the table below).

Table A10: Consortium estimate of BNE weighted average cost of capital

	RoI			UK		
Element	**2009**	**Low**	**High**	**2009**	**Low**	**High**
Risk-free rate	2.11%	1.50%	2.25%	2.51%	1.50%	2.00%
Debt premium	2.25%	3.00%	4.00%	2.25%	2.50%	3.50%
Cost of debt	**4.36%**	**4.50%**	**6.25%**	**4.76%**	**4.00%**	**5.50%**
ERP	5.50%	4.50%	5.00%	5.50%	4.50%	5.00%
Equity beta	1.39	1.20	1.30	1.25	1.2	1.3
Post-tax cost of equity	**9.75%**	**6.90%**	**8.75%**	**9.38%**	**6.90%**	**8.50%**
Taxation	12.5%	12.5%	12.5%	28.0%	28.0%	28.0%
Pre-tax cost of equity	**11.15%**	**7.90%**	**10.00%**	**13.03%**	**9.60%**	**12.00%**
Gearing	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
Pre-tax WACC	**7.07%**	**5.85%**	**7.75%**	**8.07%**	**6.25%**	**8.00%**