Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant
&
Capacity Requirement
For the Calendar Year 2013

Consultation Paper

May 2012

AIP/SEM/12/029

1 EXECUTIVE SUMMARY

The Best New Entrant (BNE) peaking plant is recommended to be an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

The estimated annualised fixed cost, net of estimated Infra-Marginal Rent and Ancillary Services revenue is €76.37/kW/year.

The Capacity Requirement for 2013 is 6,923MW.

The product of these price and quantity elements yields an Annual Capacity Payment SUM (ACPS) of €528,709,510.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2013	76.37	6,923	528,709,510

This compares to an ACPS of € 528,120,120 for the 2012 capacity year.

2 CONTENTS

3 INTRODUCTION

On 1 November 2007 the Single Electricity Market ("**SEM**"), the new all-island arrangements for the trading of wholesale electricity, was implemented. The SEM is a gross mandatory pool which includes a marginal energy pricing system and an explicit Capacity Payment Mechanism ("**CPM**"). The CPM is a fixed revenue mechanism which collects a pre-determined amount of money, the Annual Capacity Payment Sum ("**ACPS**") from purchasers (suppliers) and pays these funds to available generation capacity in accordance with rules set out in the Trading and Settlement Code ("**T&SC"**). The value of the Annual Capacity Payment Sum is determined as the product of two numbers:

- A Quantity (the Capacity Requirement) - determined as the amount of capacity required to exactly meet an all-island generation security standard; and
- A Price - determined as the annualised fixed costs of a best new entrant ("**BNE**") peaking plant.

The methodology for the determination of the fixed costs of a BNE peaking plant was set out by the Northern Ireland Authority for Utility Regulation ("**the Utility Regulator**") and the Commission for Energy Regulation ("**CER**") (together the Regulatory Authorities ("**RAs**")), in two decision papers published on the All-Island Project website in 2007[1]. Subsequently, the RAs reviewed these costs in relation to the determination of the value of ACPS for the calendar year 2008[2]. The same process was used for the calculation of the fixed costs of a BNE peaking plant for all subsequent years. The consultation paper and final decision paper for 2012 were published on the AIP website[3]. The Annual Capacity Payment Sums for all previous years are summarised in Appendix 1 of this paper.

This Consultation Paper sets out:

1. The options for the BNE peaking plant for 2013 and proposes a technology option. The paper then explores the fixed costs associated with the proposed technology option as well as the financial parameters and sets out the proposed resultant value in €/kW/year.

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[1] Fixed Costs of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Decision and Further Consultation Paper (AIP/SEM/07/14);
Fixed Costs of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Final Decision Paper (AIP/SEM/07/187)

[2] Annual Capacity Payment Sum: Final value for 2008 (AIP/SEM/07/458)

[3] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=a6ac980b-67cc-4f29-a786-a40ae5f7d28f

2. The proposed Capacity Requirement for 2013 and the approach used for its determination.

The RAs (in line with the 2012 BNE calculation) have engaged Cambridge Economic Policy Associates ("**CEPA**") in association with Parsons Brinckerhoff ("**PB**") to assist in the calculation of the fixed costs of a BNE peaking plant for 2013.

This paper covers the key recommendations made by CEPA/PB, and provides the RAs' proposed position on the various components.

The structure of this document is as follows:

Section 3 introduces the consultation paper and describes the contents within;

Section 4 sets out the background to the development of the CPM;

Section 5 describes the outcomes of the CPM Medium Term review;

Section 6 examines the technology options available in considering which generation set represents a best fit for the BNE peaking plant;

Section 7 presents the investment cost estimates for the BNE peaking plant;

Section 8 looks at the recurring costs a BNE peaking plant could expect to incur;

Section 9 considers the economic and financial parameters to be used in the evaluation;

Section 10 contains a proposal of the Best New Entrant Peaker for 2013;

Section 11 presents the Infra-Marginal Rent for the chosen BNE technology;

Section 12 presents the Ancillary Service revenues calculations for the chosen BNE technology;

Section 13 provides an indicative value for the proposed BNE peaking plant fixed cost;

Section 14 details the calculation of the Capacity Requirement for 2013;

Section 15 provides an indicative value for the Annual Capacity Payment Sum for 2013 based on the proposals in this document;

Section 16 invites comments and views;

Appendix 1 summarises the Annual Capacity Payment Sum for all previous years;

Appendix 2 compares the costs for the 2012 BNE Peaker and the 2013 BNE Peaker;

Appendix 3 contains tables of the Low/Medium/High Demand Forecast.

Appendix 4 contains a copy of the CEPA report provided to the RAs for the 2013 Calculations.

4 BACKGROUND

In May 2005 the Regulatory Authorities (RAs) set out the options for the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM)[4]. In the paper the RAs indicated their proposal to develop a fixed revenue CPM that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code.

In March 2006[5] a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of alternative options for the CPM. The processes that the RAs proposed for determining the annual capacity payment and the general process by which the input parameters to the CPM would be set were also covered.

The March 2006 paper re-iterated the proposed outline of the CPM for the SEM suggesting that annual capacity payments should be fixed and that the annual fixed sum be divided into a number of within-year pots (i.e. Capacity Periods). The paper also set out proposals for the determination of the Annual Capacity Payment Sum (ACPS). The paper proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator. The RAs proposed that, for the purposes of determining the ACPS, the cost of new entrant generation should be assessed in terms of a 'Best New Entrant' (BNE) peaking plant.

The Regulatory Authorities also determined that the resulting cost should be adjusted to account for the infra-marginal rent the BNE peaking plant may derive through its sale of energy into the pool, as well as the estimated revenues the plant may derive through its operation in the Ancillary Services markets. The infra-marginal rent was to be determined through a series of Plexos market model runs, configured with the most up-to-date data from the RAs' Market Modelling Team. The Ancillary Services revenues were to be determined by reference to the prevailing Ancillary Service arrangements in the jurisdiction in which the BNE peaking plant was determined to be located.

[4] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=0e5940cb-4c5d-4e01-982d-2b3587c33d2d

[5] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=94ef0599-001a-4923-a706-7682f76ec79b

The resulting cost of the BNE peaking plant calculated would be expressed in €/kW per year (as an annualised payment) and multiplied by the capacity requirement to calculate the ACPS.

5 UPDATE ON THE CPM MEDIUM TERM REVIEW

5.1 BACKGROUND

On 9 March 2009 the SEM Committee ("**SEMC**") published a consultation paper titled ***Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper*** (SEM-09-023)[6]. The purpose of the consultation paper was to propose options to address a key concern raised by industry participants regarding the stability of the capacity payment pot due to the annual determination of the Best New Entrant Fixed Cost ("**BNEFC**") and the Annual Capacity Payment Sum ("**ACPS**"). In the paper, the SEMC signalled its intention to carry out a further review of the CPM in the medium term. The main purpose of this review is to examine if the current design of the CPM can be further improved to better meet the CPM objectives.

5.2 CPM MEDIUM TERM REVIEW

The SEMC considers the CPM as a key feature of the SEM design. The SEMC believes that extensive analysis and consultation on this topic took place prior to SEM Go Live and that the concept of the CPM should remain in place. The SEMC wishes to satisfy that the correct signals and appropriate incentives are inherent in the design, so as to meet its objectives optimally. In particular it is mindful that the CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance.

On 8 April 2009 the SEMC published a consultation paper (SEM-09-035)[7], documenting the scope of work that the SEMC proposed to carry out in relation to a medium term review of the CPM.

The areas under consideration in this paper (SEM-09-035)[9] are detailed below:

- Assessment of CPM in SEM (historical analysis);
- Impact of CPM on customers;
- Incentives for Generators Capacity;
- Payments when Capacity is needed;
- Distribution of Capacity Payments;
- Capacity Requirement Calculation;

[6] http://www.allislandproject.org/GetAttachment.aspx?id=9f4bfc9b-5f60-4ca4-8a84-58158a5bb14f

[7] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=4dde96cc-fdda-458b-9a3c-dc4a00692ac5

- WACC Methodology;
- Infra Marginal Rent & CPM;
- Impact of Exchange Rate in CPM;
- Treatment of Wind in CPM;
- Treatment of Interconnector in CPM;
- Relationship of CPM with Ancillary Services; and
- Impact on Diversity of Generation & Security of Supply.

To date the RAs have published three consultation / discussion papers[8].

The SEM Committee in July 2010 published a Discussion Paper on the historical aspects of the CPM Medium Term Review (SEM-10-046). The paper covers the Work Packages 1-5 of the Medium Term Review.

- Work Package 1 - Historical Analysis of CPM;
- Work Package 2 - Review of Capacity Requirement;
- Work Package 3 - Deduction of IMR & AS & BNE Peaker Plant Options;
- Work Package 4 - BNE Peaker Plant Fuel Options;
- Work Package 5 - Exchange Rate for CPM.

In October 2010 the SEMC publish a Consultation Paper as part of the Medium Term Review of the Capacity Payment Mechanism on Work Package 7 - BNE Calculation Methodology (SEM-10-068). The paper looked at the following areas:

- CPM Design in other Regions and International experiences in delivering adequate capacity;
- BNE Calculation Methodology 2006;
- Summary of the Options in the BNE Calculation Methodology Review 2009 - option 2, 5 and 6;
- Indexing Methods;
- Impact of Options on WACC Calculations.

In April 2011 the SEMC published the final Consultation Paper looking at the final outstanding work packages (SEM-11-019). The paper looked at the following areas:

[8] All these papers can be found at the following link: http://www.allislandproject.org/en/cp_current-consultations.aspx?article=31822151-f6da-4f5a-9fba-61739dd35f98

- Work Package 6 - Treatment of Generator types in the CPM,
- Work Package 8 - Incentives for Generators,
- Work Package 9 - Timing and distribution of Capacity Payments,
- Work Package 10 - Impact of the CPM on Customers.

5.3 OUTCOME OF MEDIUM TERM REVIEW

In March 2012, the SEMC published the final decision paper on the CPM Medium Term Review (SEM-12-016)[9]. The decisions made are described in full in the decision paper, and are also summarised below.

5.3.1 FORCED OUTAGE PROBABILITY

The previous Forced Outage Probability ("**FOP**") used in the calculation was defined as 4.23%. The revised targeted FOP has been calculated to be 5.91%.

The SEMC recognise that the revised FOP of 5.91% is lower than the average FOP on an all-island basis. However, it should be noted that reflecting the poor performance of plant in the determination of the Capacity Requirement will effectively provide compensation to units which perform poorly. One of the objectives of the CPM is to provide an incentive for improvements in plant availability and the RAs believe that by continuing to maintain the Capacity Requirement against a targeted FOP value, generators will continue to be provided with an incentive to improve their performance towards the target level.

5.3.2 INFRA MARGINAL RENT

The SEMC have decided that Infra Marginal Rent ("**IMR**") will be deducted from the BNE through the following calculation:

IMR DEDUCTED IN €/KW = [PCAP-BID]/100 * OUTAGE TIME * (1-FOP)

This method should heavily reduce the level of volatility and/or potential uncertainty currently in place regarding the IMR deduction. The key variables in the method are semi-fixed such as

[9] http://www.allislandproject.org/en/cp_decision_documents.aspx?page=1&article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

the Trading and Settlement Code Price Cap (PCAP) and Generation Security Standard (GSS / Outage Time). Therefore the deduction should be able to be forecast by investors with reasonable accuracy. The only 'floating' variable is the bid price of the BNE unit, which will be driven by prevailing fuel prices (e.g. the price of distillate in the case of a distillate fired plant).

5.3.3 THE BNE WILL REMAIN CONSTANT FOR THREE YEARS

The RAs consider that a 'Component Period Horizon' of three years can bring some stability and certainty to the volatility in the annual capacity pot. This will give capacity providers, particularly new entrants, greater certainty. Elements such as the Technology Options/EPC Investment costs will remain constant but indexed over the following two years.

For indexing, the €/kW/year value will be determined by taking its value in the preceding years and applying the annual inflation rate in the region that the WACC/economic parameters are applied[10]. For example, if the BNE is in Northern Ireland and a UK WACC is used, then the UK inflation rate will be used to index the €/kW/year value.

Other elements such as the Capacity Requirement and the Trading & Settlement Code parameters will continue to be calculated on an annual basis in conjunction with the TSOs.

5.3.4 ANCILLARY SERVICES DEDUCTIONS

The Regulatory Authorities will continue to work with the Transmission System Operators (TSOs) to define additional Ancillary Services (AS) if required and the value of these services to the system as highlighted in the Harmonised All-Island Ancillary Services Policy decision paper (SEM/08/013)[11]. The TSOs also have the ability to suggest new or modified services if considered of benefit to the efficient operation of the system. The RAs continue to believe that the responsibility of incentivising the type of operational generation capacity required maintaining system security and reliability falls within the remit of ancillary service payments. As previously stated the Regulatory Authorities believe that the CPM is tailored to ensure that it would pay a Best New Entrant (BNE) peaker generator at a sufficient rate to cover its long run costs, given forward looking estimates of its running and all its other revenues, including ancillary services revenues.

[10] The sources for the data on inflation are the Central Statistical Office (CSO) in Ireland and the Office for National Statistics (ONS) in the UK.
Ireland - http://www.cso.ie/en/statistics/prices/consumerpriceindex
UK - http://www.ons.gov.uk/ons/publications/all-releases.html?definition=tcm%3A77-22462
[11] http://www.allislandproject.org/GetAttachment.aspx?id=20252281-e52a-4ae5-a2a4-102c8546b045

In 2012 the TSOs in cooperation with the Regulatory Authorities will be undertaking a Systems Services Review (DS3)[12] multi-stage consultation process, to incorporate the views of industry on the arrangements for System services. The TSOs are currently investigating the specific definitions of System Services and the requirement quantities over the medium to long term. These proposals / services identified may impact the AS revenues earned by the BNE over the three year period. The Regulatory Authorities reserve the option to review the AS reduction in future years of this period, if they believe it is appropriate to do so.

5.3.5 TIMING AND DISTRIBUTION OF CAPACITY PAYMENTS

The SEM Committee continues to believe that the current 30%, 40% and 30% ratio of respectively the Fixed Ex-ante, Variable Ex-Ante and Variable Ex-Post weighting components gives the appropriate balance between a short term signal to provide the required capacity during periods of tight capacity margin, and the longer term certainty over capacity revenues for generators.

In the Draft decision paper the SEM Committee indicated their preference to increase the Flatting Power Factor (FPF) to 0.5. In September 2012 the Regulatory Authorities will be publishing the TSOs' Proposed Value for the Flattening Power Factor for the year 2013. The SEM Committee will reserve its decision until the outcome of this report is known. The proposed FPF change, if any, will be published at this time. This will allow respondents the opportunity to comment on any potential changes to the FPF that will affect the 2013 distribution of the Pot.

[12] http://www.eirgrid.com/operations/ds3/ds3programmeoffice/

6 TECHNOLOGY OPTIONS

As stated earlier, the RAs have employed CEPA in association with PB to assist in the calculation of the fixed costs of a BNE peaking plant for 2013. As with the previous two years their approach remains substantively similar, their independent report is detailed in Appendix 4 of this document and is referenced throughout this paper.

6.1 APPROACH USED FOR SELECTION OF TECHNOLOGY

In the interests of consistency the RAs required CEPA/PB to build on the approach used in previous years. The approach used by CEPA/PB is documented in Section 2 of their report.

The approach and subsequent selection of the BNE plant is influenced by the following considerations:

- The BNE is a notional plant that would serve the last MW on the system;
- The plant is expected to operate no more than 2% of the time;
- The plant will enter the SEM in 2013;
- It should be noted that the period to build the plant is 18 months with a lead time for the transformer of 12 months.

In previous BNE Peaker consultation processes there were a number of comments and opinions on whether the fuel used by the BNE Peaker would be distillate or gas. The RAs continue to take note of these comments and have considered both fuel types in the section of a suitable technology.

6.2 CRITERIA FOR SELECTION

Similar to previous years, a long list of potential options was developed by CEPA/PB to which the criteria for selection were then applied. The methodology employed was to use a series of ‘pass/fail’ criteria to the long list in order to reduce the number of feasible options. This process resulted in a short list where a more detailed analysis could be carried out.

The development of the long list for 2013 has been drawn from the conclusions previously reached through the 2010, 2011 and 2012 CPM consultation process. The long list of potential options contained 22 conventional plant types of different manufacturers, type and size, of which the details of the long list can be found in Annex 1 of the CEPA Report. To ensure a robust analysis, the aero-derivative GTs with the best specific equipment cost were also included such that the effect of any relative performance improvements from water injection or EPC cost advantages of containerised systems might be captured. Consequently, the following peaking options were not considered for the short-listing process:

- Second-hand plants;
- Interconnectors;
- AGUs.

The criteria used to reduce the long list to a short list are as follows:

- The technology option must still be commercially available;
- The technology option must have a proven track-record (typically defined as three examples of over 8,000 running hours);
- The unit sizes must be between 30 and 200MW;
- The technology option must ramp up to full load in less than 20 minutes;
- The technology option must be able to fire liquid fuel;
- The technology option must meet all environmental requirements (e.g. Maximum NO_x value for distillate firing = 90Mg/Nm^3 and for gas firing = 50 Mg/Nm^3)

6.3 SHORTLIST OF TECHNOLOGY OPTIONS

Using the criteria discussed in the above section 6.2 the number of options was reduced from 22 to 12. In order to further reduce the list of options to a manageable number to allow a detailed analysis, a comparison of equipment costs was carried out. The costs were based on the equipment costs published in the Gas Turbine World 2010 GTW Handbook[13]. As a result of this analysis a recommended short list of options was proposed and a detailed analysis of these units was undertaken.

The short listed units are:

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

[13] The 2011 edition of the Handbook is not yet available

Further details on the selection of these units are discussed in the CEPA/PB report in section 3.3.1.

6.4 OTHER TECHNOLOGY OPTIONS CONSIDERED

The Interconnector was deemed as unsuitable as there is a level of uncertainty as to whether the Interconnector would definitely be able to supply the last MW of load in all situations.

While AGU technology is currently operating in the SEM and appears to be well established and controllable under the desired requirements for a peaking plant, it was noted that the existing level of installed capacity is low, and it would be almost impossible to theoretically serve a sizable proportion of SEM demand with this technology. This is an important point because technologies which have a 'carrying capacity' could distort the signals sent by the CPM if used as the BNE peaker, it was felt that it still remains a prototype technology for being a BNE peaker.

Pumped storage was not considered, even though the RAs have in the past been in discussions with investors that are actively considering this sort of investment. This technology was deemed unsuitable due to the limited number of suitable sites and the total capital costs coming in between the central to high estimates.

6.5 ENGINEERING, PROCUREMENT & CONSTRUCTION (EPC) ANALYSIS

Based on the short-listed technology options detailed in section 6.3, a more detailed cost analysis was carried out of the shortlist to consider the investment costs for each option. As mentioned above, each of the five options was analysed taking into consideration the costs for the units running on gas and the costs for the units running on distillate.

CEPA/PB carried out a detailed analysis of the five options short listed using the software package GT Pro in conjunction with its cost-estimating tool PEACE[14]. CEPA/PB took the values of EPC costs from the GT PRO Version 20 tool; they then compared these with relevant actual costs they have experienced from projects that they have carried out in recent years. They then provided all the OEMs of the candidate plants the opportunity to provide the results of their own in-house performance simulations and to provide feedback on CEPAs Thermo-flow yields.

[14] GT PRO Version 20, GT MASTER and the associated PEACE programme are well established and respected GT thermal modelling and cost estimating software packages from Thermoflow Inc.

It is noted there has been a slight increase in the lifetime output of a number of candidate plants in the CEPA 2013 BNE report. This is driven by requirements for greater water injection to meet IED environmental limits on NO_x. Changes to average lifetime output are based on the final release of GT Pro Version 20 and consultation with the OEM plant manufacturers. The RAs are satisfied with the approach taken by CEPA/PB.

The EPC Cost estimates provided by CEPA/PB are detailed in Table 5.1 below.

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

Table 6.1 – *Summary of Proposed EPC costs for Short Listed Plants*

Further information on the EPC costs and assumptions used can be found in the CEPA/PB report in section 3.4.

6.6 PROPOSED TECHNOLOGY OPTION

As in previous years, a screening curve analysis was carried out for the five short listed options for both distillate and gas. The costs used in the screening curve include the EPC costs discussed above as well as the investment and recurring cost as discussed in Section 6 and Section 7 of this paper. The variable costs that would be bid into the energy market are also considered in the screening curve analysis. The screening curve analysis graphs are shown below for both gas and distillate.

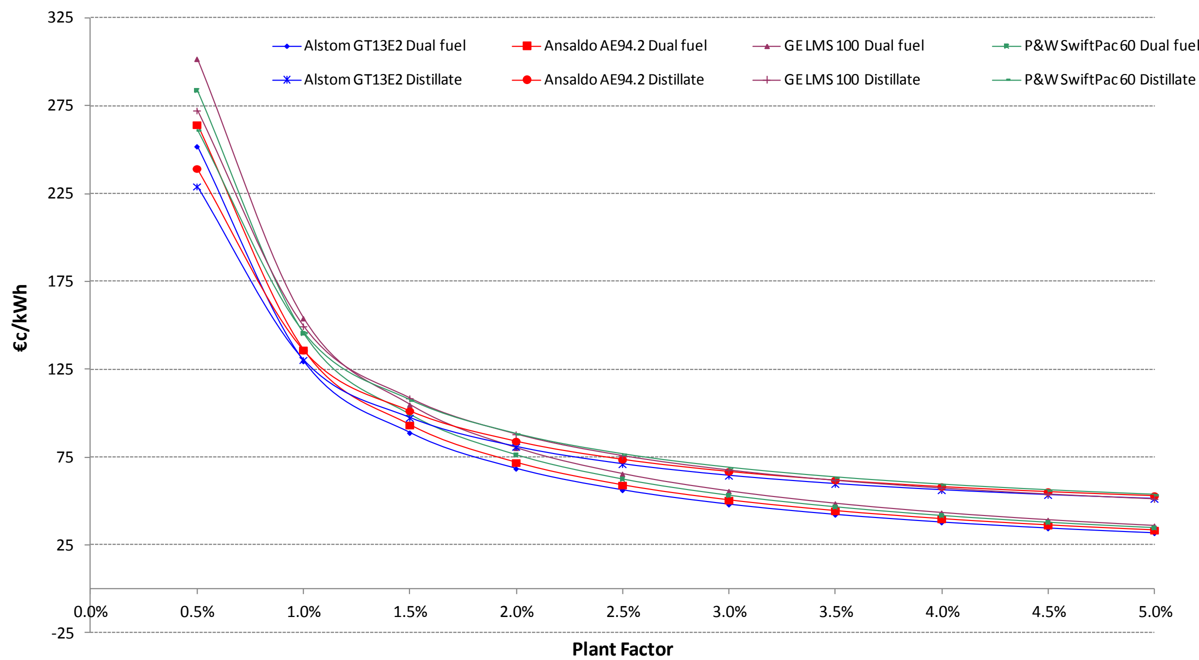

Figure 6.1 – *Screening Curve Analysis for Dual Fuel and Distillate*

Based on the screening curve analysis, the Alstom GT13E2 and Ansaldo AE94.2 are more favourable than the General Electric LMS100 and P&W Swift options.

Based on the plant factor range of 0.0% to 5.0% used in the screening curve analysis, the costs associated with the Alstom GT13E2 are lower that the Ansaldo AE94.2 costs.

Therefore, the recommendation for the technology to be used for the BNE Peaker 2013 is the Alstom GT13E2. The Alstom GT13E2 was the best option for both distillate and gas fuelling options in the screening curve analysis. This plant has a capacity of 202MW in dual fuel configuration[15].

Further information on the recommendation can be found in the CEPA/PB report in section 3.5. In addition, the key assumptions used in the selection of the technology option are also detailed.

The Proposed Technology Option for the BNE Peaker 2013 is the Alstom GT13E2

[15] The capacity of the unit has increased as Alstom have launched an upgrade of the GT13E2.

7 INVESTMENT COSTS

This section details the key cost areas that make up the capital costs of the BNE Peaker. The key cost areas given consideration are:

- EPC Costs;
- Site Procurement costs;
- Electrical Connection costs;
- Gas and Make-up Water Connection costs;
- 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.

These are discussed in the following sections of this paper. Further details are available in Section 4 of the CEPA/PB report.

For the purposes of the BNE calculation the RAs viewed that the spot rate at time of developing document was appropriate. This rate was a Euro to Sterling exchange rate of 1.1958[16] on 30 March 2012. As the decision paper should contain the most up to date information for the purpose of the calculation this rate will be reviewed at the time of writing the decision paper.

7.1 EPC COSTS

The EPC costs are covered in section 5.5 above. Table 7.1 summaries the proposed EPC costs for the Alstom GT13E2 for each fuel type. There is a difference in the EPC cost in the two locations due to the difference in costs associated with the differing transmission voltages. It should be noted that the costs below assume the period to build the plant is 18 months with a lead time for the transformer of 12 months being on the critical path.

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[16] The exchange rate used for the assessment is £1=€1.1958 (Source: http://www.oanda.com/currency/table on 30 March 2012)

Plant Type	Location	Fuel Type	EPC Cost (€m)
1 x Alstom GT13E2	NI	Distillate	92.5
		Dual	92.4
	RoI	Distillate	93.7
		Dual	93.7

Table 7.1 – *Summary of Proposed EPC costs for* Alstom GT13E2

7.2 SITE PROCUREMENT COSTS

The RAs in conjunction with CEPA/PB considered options for a suitable location in both Northern Ireland and the Republic of Ireland. The area of land needed is estimated to be around 20,600m^2 (a distillate plant requires a slightly larger area (20,700m^2) than a dual-fuel plant (20,500m^2)).

For Northern Ireland, the preferred option considered was the site of the former Belfast West Power Station. This land has been cleared of the original power station and is part of the land-bank area reserved by the Utility Regulator and managed by NIE for generation construction in the future. Following a Land Bank consultation[17] on Vacant Sites within the NIE Land Bank, all sites which includes the Belfast West site has been made available for sale/lease. The Utility Regulator has issued NIE's Land Bank business with a direction that instructs them to appoint an appropriately qualified and suitable person to act as agent on their behalf. The agent will be responsible for issuing a request for proposals for the sites, taking receipt of proposals and acting as liaison with those interested in and making proposals. This has been the site for the last few BNE reports.

The RAs and CEPA are proposing to maintain the notional rate of €150k/acre for 2013. Respondents' views are welcome on this assumption.

These costs are detailed in the table below. Further details are available in Section 4.3.4 of the CEPA/PB report.

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

Location	Fuel type	Required area (m^2)	Estimated site cost (€)
Northern Ireland	Distillate	20,700	€1,529,154
	Dual	20,500	€1,514,379
Republic of Ireland	Distillate	20,700	€767,262
	Dual	20,500	€759,849

Table 7.2 – *Summary of Site Procurement Costs*

7.3 ELECTRICAL CONNECTION COSTS

The RAs worked closely with the TSOs in determining the electrical connection costs. For Northern Ireland, it was assumed that a 110kV connection would be used for the Belfast West site. In the Republic of Ireland, it was assumed that the connection would be at 220kV and require a 4km connection.

The costs for each site are summarised in the table below:

Location	Electrical Connection Cost (€)
Northern Ireland	€7,870,000
Republic of Ireland	€6,860,000

Table 7.3 – *Summary of Electrical Connection Costs*

7.4 GAS AND MAKE-UP WATER CONNECTION COSTS

CEPA/PB provided the following estimates for Gas and Water Charges for each location.

Location	Cost of water connection (€)	Cost of gas connection (€)
Northern Ireland	0	€1,810,000
Republic of Ireland	€480,000	€3,620,000

Table 7.4 – *Summary of Gas and Make up Water Connection Costs*

The assumptions used for Northern Ireland was that minimal water connection costs would be incurred due to the proximity of the water mains to the proposed site. For gas a 1km gas pipeline to Belfast West was assumed.

The assumptions used for the Republic of Ireland were an installed 1km water pipeline, four inches in diameter and a 2km gas pipeline to the site.

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 capacity trading. The RAs are committed to working together to establish Common Arrangements for Gas for Northern Ireland and Ireland, whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market effectively on an all-island basis. On 3 February 2012 the RAs published their latest Industry Update on the Common Arrangements for Gas (CAG)[18]. However at the time of this writing the standing policy from the SEM Committee stands, in that the cost of gas transportation capacity remains best interpreted as fixed.

On that basis our estimates for gas capacity charges are shown below. Similar to the response document last year CEPA have used the following calculation for the Republic of Ireland:

(Plant Output/ Load Factor/ Calorific Value Conversion Factor) x Running Hours x (Onshore Tariff + Interconnector Tariff) = Total Gas Transmission Charges

And for Northern Ireland:

(Plant Output/ Load Factor/ Calorific Value Conversion Factor) x Running Hours x (Postalised Tariff) = Total Gas Transmission Charges

RoI transmission charges are available from Gaslink for 1 October 2011 to 30 September 2012[19]. The postalised capacity charge for the Northern Ireland transmission system is published by Bord Gais Networks, including a forecast for gas years 2012/13 to 2015/16[20]. CEPA have used the forecast Northern Ireland postalised capacity charge for the 2012/13 gas year.

7.5 OWNER'S CONTINGENCY

As with previous years' reports CEPA/PB has recommended an owner's contingency value of 5.2% of the EPC costs. This is based on their past project experience. Therefore in the case of the Alstom GT13E2 the estimated Owners Contingency is detailed in table 7.5.

[18] http://www.allislandproject.org/en/cag_publications.aspx?year=2012&section=1&article=aec5a487-f4d1-40a1-8711-957630991fe4

[19] http://www.gaslink.ie/index.jsp?p=289&n=180

[20] http://www.bordgaisnetworks.ie/en-IE/Gas-Industry/Northern-Ireland/Transportation-services/Postalised-Tariffs/

Location	Fuel Type	Owner's Contingency Cost (€m)
Northern Ireland	Distillate	€4,810,000
	Dual Fuel	€4,804,800
Republic of Ireland	Distillate	€4,872,400
	Dual Fuel	€4,872,400

Table 7.5 – Summary of Owners Contingency costs for Alstom GT13E2

7.6 FINANCING, INTEREST DURING CONSTRUCTION (IDC) AND CONSTRUCTION INSURANCE

Similar to the Owner's Contingency, CEPA/PB have estimated the costs associated with Financing and Construction Insurance as a percentage of the EPC costs while the Interest During Construction (IDC) estimate is based on their project experience and are calculated on a jurisdictional basis. These are summarised in table 7.6.

	Total Cost for Distillate (€)	Total Cost for Duel Fuel (€)
Financing NI	€1,850,000	€1,848,000
Financing RoI	€1,874,000	€1,874,000
IDC NI	€2,204,216	€2,233,493
IDC RoI	€3,305,708	€3,406,774
Construction Insurance NI	€832,500	€831,600
Construction Insurance RoI	€843,300	€843,300

***Table 7.6** – Summary of Financing, IDC and Construction Insurance costs for Alstom GT13E2*

7.7 INITIAL FUEL WORKING CAPITAL

It is necessary to include the costs of fuel which needs to be held to comply with various regulatory policies as a BNE capital cost. This is required for a gas plant to adhere with the secondary fuel obligation in the Republic of Ireland. The fuel security code for Northern Ireland is currently under review therefore it is assumed that the above obligation would be applicable in either jurisdiction.

CEPA/PB has estimated an initial fuel storage fill cost of €5.04m for a distillate plant and €4.23m for a dual fuel plant. This is based on a requirement to run for 72 hours full load, an additional 0.5 days of commercial running and an oil price of US$123.24/ barrel[21].

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Working Capital for Fuel (either jurisdiction)	€5,044,812	€4,277,704

Table 7.7 – *Summary of Fuel Working Capital*

Note that there are other initial working capital assumptions that are considered in the final calculations in section 9.

7.8 OTHER NON-EPC COSTS

CEPA/PB grouped the remaining costs together to allow a logical comparison of the data they held on their project experiences. The cost areas included under 'Other Non-EPC Costs' include EIA, legal, owner's general and administration, owner's engineer, start-up utilities, commissioning, O&M mobilisation, spare parts and working capital. Based on CEPA/PB's experience, the Other Non-EPC Costs equates to 9.0% of the EPC Costs.

As with the calculation for 2012 the data used in calculating the percentage allocation for Other Non-EPC Costs was presented to the RAs but due to confidentiality, the derivation of this percentage allocation cannot be included in this paper. The RAs are satisfied with the approach taken by CEPA/PB in determining the Other Non-EPC Costs.

Location	Fuel type	Other non-EPC costs (€)
Northern Ireland	Distillate	€8,325,000
	Dual	€8,316,000
Republic of Ireland	Distillate	€8,433,000
	Dual Fuel	€8,433,000

Table 7.8 – *Summary Other Non-EPC costs for Alstom* GT13E2

[21] Oil price used was ICE Brent Crude as traded on 30 March 2012 (source Bloomberg)

7.9 MARKET ACCESSION AND PARTICIPATION FEES

Similar to previous years, the required fees to enter the SEM were considered. Based on the current tariffs, these will cost €3,903 and although small are included for completeness. These charges are payable to the market operator, SEMO.

Type of charge	Charge Cost (€)
Accession Fee	€1,115
Participation Fee	€2,788

Table 7.9 – *Summary of Market Fees*

7.10 SUMMARY OF INVESTMENT COSTS

The table below summarises all the investment cost for the Alstom GT13E2 for each jurisdiction and for each fuel type.

Cost Item	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
EPC Costs	€92,500,000	€92,400,000	€93,700,000	€93,700,000
Site Procurement	€1,529,154	€1,514,379	€767,262	€759,849
Electrical connection Costs	€7,870,000	€7,870,000	€6,680,000	€6,680,000
Water connection	€0	€0	€480,000	€480,000
Gas connection	€0	€1,810,000	€0	€3,620,000
Owners Contingency	€4,810,000	€4,804,800	€4,872,400	€4,872,400
Financing Costs	€1,850,000	€1,848,000	€1,874,000	€1,874,000
Interest During Construction	€2,204,216	€2,233,493	€3,305,708	€3,404,774
Construction Insurance	€832,500	€831,600	€843,300	€843,300
Initial Fuel working capital	€5,044,812	€4,227,704	€4,434,796	€3,716,492
Other non EPC Costs	€8,325,000	€8,316,000	€8,433,000	€8,433,000
Accession & Participation Fees	€3,903	€3,903	€3,903	€3,903
Total	**€124,969,584**	**€125,859,879**	**€126,068,214**	**€129,063,563**

Table 7.10 – *Summary of Investment Costs for Alstom* GT13E2

It should be noted that at this stage the options using Gas are the more expensive options mainly due to the Gas connection costs. With the secondary fuel obligation, the distillate storage facilities need to be considered too for both fuel types.

8 RECURRING COSTS ESTIMATE

As well as the Investment Costs, a rational investor would need to consider the recurring costs incurred on an annual basis. The main areas of recurring costs identified are:

- Market Operator charges
- Transmission TUoS charges
- Gas Transmission Charges
- Operation and Maintenance Costs
- Insurance
- Business Rates
- Fuel working capital

Each of these areas is discussed in section 4.4 of the CEPA/PB report including the assumptions used in determining the cost estimates.

In relation to the Market Operator Charges, TUoS charges and Gas Transmission charges, the current published tariffs were used as sources. If updated tariffs relating to 2013 are available ahead of a decision on the cost of the BNE Peaker for 2013, the values in the table below will be adjusted accordingly to reflect these.

Cost Item	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
Transmission & Market operator charges	€1,168,105	€1,177,009	€998,543	€1,006,155
Gas Transmission Charges	€0	€4,055,606	€0	€6,080,654
Operation and maintenance costs	€1,902,000	€1,928,000	€1,903,000	€1,929,000
Insurance	€1,480,000	€1,478,400	€1,499,200	€1,499,200
Business Rates	€695,082	€700,380	€1,538,343	€1,550,069
Fuel working capital	€325,523	€272,798	€376,577	€315,583
Total	**€5,570,710**	**€9,612,193**	**€6,315,664**	**€12,380,660**

Table 8.1 – *Summary of Recurring Costs for BNE Peaker for 2012*

The Proposed Fuel Option for the BNE is Distillate

9 ECONOMIC & FINANCIAL PARAMETERS

9.1 INTRODUCTION

As with previous years, a key activity in the calculation of the BNE Peaker is the determination of the Weighted Average Cost of Capital ("**WACC**"). CEPA/PB have carried out an extensive investigation of the building blocks of WACC. Their analysis is detailed in Section 5 and Annex 2 of the CEPA/PB paper. The format and approach CEPA/PB used in this section follows on from the format and approach that was used for the BNE calculation for the previous trading year.

9.2 NATURE OF THE BNE INVESTMENT

As part of the CEPA/PB analysis, a number of assumptions were discussed and agreed with the RAs on the nature of the BNE investment. These are discussed in more detail in section 5.1.2 of the CEPA/PB report. The main assumptions are detailed below.

Area	Assumption
Type of Investor	It is assumed 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. In addition, it is assumed that the BNE is a green-field investment with no existing assets and associated financing costs.
Plant Life	The economic life of the project has been taken as 20 years.
Financing Structure	It is assumed 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. Therefore it is assumed that an average tenor of 10 years on the new debt. It is also assumed 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%. This is the same level of gearing as was used in the 2009 and 2010 calculations.
Credit Quality	It is assumed that a BNE investor has an investment grade credit rating in the range BBB to A

Table 9.1 – *Summary of Assumptions on the Nature of Investment*

9.3 WACC PROPOSALS

Annex 2 of the CEPA report provides a comprehensive summary of the assumptions used by CEPA/PB in their recommendation of the WACC to be used for the BNE Peaker for 2013. In summary, CEPA/PB recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 5.71% - 11.27% in the Republic of Ireland and 5.58% - 7.32% in the UK.

A summary of the WACC parameters provided by CEPA is detailed in table 9.2 below[22]. The 2012 WACC values have been included to allow a comparison.

[22] CEPA/PB has been retained by the RAs to provide their independent assessment of the likely range of the cost of capital for an international investor in the SEM, both in ROI and NI. The CEPA approach differs from that adopted by the CER in past ROI network price controls. In CER's view the main area of difference is in relation to the risk free rate in which CEPA/PB appear to include a country specific risk premium, with the result that CEPA's estimate of the risk free rate is not strictly devoid of default risk. The CER has to date adopted an approach where the risk free rate represents the return on a risk free asset in the euro-zone and hence which includes no risk premium; and that any specific country risk premium would be added elsewhere in the WACC build-up, e.g. in the equity beta and the debt premium over the risk free rate. The inclusion by CEPA/PB of a country risk specific risk premium in the risk free rate does not imply that the methodology for determining the WACCs which the CER will use in future network price reviews will be bound by or follow the CEPA/PB approach.

Element	RoI 2012	RoI 2013 Low	RoI 2013 High	UK 2012	UK 2013 Low	UK 2013 High
Risk-free Rate[23]	5.50%			1.75%	1.50%	2.00%
Debt Premium	2.00%			2.00%	1.75%	2.75%
Cost of debt	**7.50%**	**3.50%**	**8.50%**	**3.75%**	**3.25%**	**4.75%**
Equity Risk Premium	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.20	1.30	1.25	1.20	1.30
Post-tax cost of equity	**11.35%**	**7.90%**	**13.50%**	**7.70%**	**6.90%**	**8.50%**
Taxation[24]	12.50%	12.50%	12.50%	26.00%	24.00%	24.00%
Pre-tax cost of equity	**12.93%**	**9.03%**	**15.43%**	**10.41%**	**9.08%**	**11.18%**
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**9.67%**	**5.71%**	**11.27%**	**6.41%**	**5.58%**	**7.32%**

Table 9.2 – *Summary of WACC parameters recommended by CEPA/PB*

The RAs have used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2013.

In previous years, the mid-point of the recommended range was taken in determining the proposed WACC. However, in the NIE Transmission and Distribution Price Controls 2012 – 2017 Draft Determination[25], a risk-free rate of 2.0% and an Equity Risk Premium of 4.8% were used. The RAs do not see any rationale to deviate from these economy-wide parameters, and therefore in calculating the UK WACC, has used this high point in the recommended range of 2.0% for risk-free rate and adjusted the Equity Risk Premium to 4.80%.

The Debt Premium is the cost above and beyond the risk-free rate; the debt premium assumed in the NIE Draft Determination is 1.2%. While the RAs recognise that the T&D business is regulated and therefore the BNE would be unable to obtain such a low debt premium, it has

[23] Please note that for ROI, the Risk-free rate and the Debt Premium will vary depending on where the Country Risk Premium to reflect the risk faced by investors in RoI is included. To take account of the different approaches, CEPA/PB have recommended a cost of debt within the range 3.50% to 8.50%. Please see Annex 2 of the CEPA/PB paper for further information.

[24] In the March 2012 UK Budget, the Government announced that it was reducing corporation tax from 26% to 24% with effect from April 2012.

[25] http://www.uregni.gov.uk/uploads/publications/RP5_Draft_Determination_-_Main_Paper_19-04-12.pdf

influenced the decision on the debt premium for the BNE. The RAs have therefore chosen the lowest point of the recommended debt premium range of 1.75%. This results in a UK cost of debt of 3.75%, equal to the cost of debt on the 2012 BNE decision.

Element	2012 RoI	2012 UK
Risk-free rate		2.00%
Debt premium		1.75%
Cost of debt	**6.00%**	**3.75%**
ERP	4.75	4.80%
Equity beta	1.25	1.25
Post-tax cost of equity	**10.70%**	**8.00%**
Taxation	12.50%	24.00%
Pre-tax cost of equity	12.23%	10.53%
Gearing	60%	60%
Pre-tax WACC	**8.49%**	**6.46%**

Table 9.3 – *Proposed WACC values to be used for the BNE Peaker for 2013*

10 PROPOSED BEST NEW ENTRANT PEAKER FOR 2013

10.1 SUMMARY OF COSTS

Based on the analysis carried out and detailed in Section 6 to Section 8 of this paper, the RAs have summarised the results of the annualised costs for the a distillate fired Alstom GT13E2 for each jurisdiction. These are summarised in table 10.1 below.

Cost Item	Units	NI	RoI
Total Investment Costs	€ million	119.79	120.96
Land and Fuel Residual Value	€ million	-1.88	-1.02
Initial Working Capital	€ million	7.64	6.93
Total Annual Costs	€ million	16.93	19.71
Plant Size	MW	196.5	196.5
Pre Tax WACC	%	6.46%	8.49%
Plant Life	Years	20	20
Estimated BNE cost (before reductions)	**€/kW**	**86.23**	**100.34**

Table 10.1 – *Annualised costs for BNE Peaker for 2013*

10.2 RECOMMENDATION FOR BEST NEW ENTRANT PEAKER FOR 2013

Based on the figures from table 10.1, the Distillate plant in Northern Ireland is the preferred option.

The Proposed Best New Entrant Peaker for 2013 is the Alstom GT13E2, located in Northern Ireland and firing on Distillate fuel

11 INFRA MARGINAL RENT

In previous years, in order to assess the infra marginal rent a BNE peaking plant might expect to receive from the energy market, assumptions were made about the future value of SMP realised in the trading periods in which the peaking plant is assumed to be active in the energy market. It is assumed that, as a profit maximising entity, the BNE peaking plant will operate in all those trading periods that provide it with infra marginal rent.

The approach to the derivation of the estimated infra-marginal rent for the BNE peaker in all previous years was to complete two *Plexos* runs, one with the BNE peaking plant and all its true characteristics included and one without. A unit commitment schedule is derived for the BNE peaking plant from the first *Plexos* run and the actual infra marginal rent calculation is then derived using the original SMP estimations from the *Plexos* run without the BNE peaking plant included. Normally to calculate the infra-marginal rent, the most up-to-date SEM Plexos model for forecasting Directed Contracts prices and quantities was used

However, as highlighted in Section 4 above, and in the Decision Paper on the CPM Medium Term Review[26], the SEM Committee have decided to amend the methodology used for calculating Infra-Marginal Rent for the 2013 BNE calculation. Infra-Marginal Rent will now be deducted from the BNE using the following formula:

IMR DEDUCTED IN €/KW = [(PCAP – BID[27])/1000] * OUTAGE TIME * (1 – FOP)

The RAs have performed this calculation, using the average bid of existing distillate peakers in the SEM on 31 March 2012. The resulting Infra-Marginal Rent to be deducted is therefore:

IMR DEDUCTED IN €/KW = [(1000 – 264)/1000] * 8 * (1 – 5.91%)

= €5.54/KW

[26] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

[27] Source: Average Bid of Distillate Peaker in the SEM on 31/03/2012

12 ANCILLARY SERVICES

The Ancillary Services (AS) rates for tariff year 2012/13 have not be developed; they will be subject of a consultation during the summer of 2012. For the calculation of the AS for the BNE peaker for 2013, the RAs have used the criteria as documented in the Decision Paper on Harmonised Ancillary Services & Other System Charges for 2011/12 (SEM-11-064)[28], developed with the SOs, detailing the proposed payments and charges. The TSOs' have published the approved rates and explanatory papers on their own websites along with the responses to the consultations on the proposed rates for the current tariff year, beginning 1 October 2010, for Ancillary Services and Other System Charges. Please refer to the following websites for details:

- http://www.eirgrid.com/operations/ancillaryservicesothersystemcharges/
- http://www.soni.ltd.uk/chargingstatements.asp

As updated information becomes available the RAs will re-evaluate the AS calculation ahead of any final decision on the Capacity Requirement for 2013. The RAs worked with the TSOs in calculating the appropriate costs for Ancillary Services under the propose criteria and formulae using the same methodology as was used in previous calculations. The assumptions used in the Ancillary Service Calculations are:

- Unit size is 196.5MW
- Run hours is 2%
- Load factor is 60%

The estimated value of Ancillary Services that the BNE peaker for 2012 would achieve is €848,354. This equates to €4.32 per kW for a 196.5MW unit. Table 11.1 shows a breakdown of the calculation used.

[28] http://www.allislandproject.org/en/transmission_current_consultations.aspx?article=e9b65b72-cb55-4184-88f2-31489c8940cf&mode=author

Cost Item	Not Running (€/TP)	Running (€/TP)
Primary Operating Reserve		23.53
Secondary Operating Reserve		37.70
Tertiary Operating Reserve 1		31.15
Tertiary Operating Reserve 2		15.58
Replacement Reserve	50.11	7.86
Reactive Power (Leading)		8.40
Reactive Power (Lagging)		19.16
Total Revenue	**50.11**	**143.38**

Table 12.1 *– Summary of Ancillary Services Costs for 2013*

The potential AS income using the RA assumptions of 95% availability and 2% run hours is therefore:

(50.11 * 0.93 * 48 * 365) + (143.38 * 0.02 * 48 * 365) = €866,713

From this figure, penalties are deducted to cover the scenario of one trip and associated Short Notice Declaration (SND) event. A 196.5MW direct trip and a 196.5MW SND at zero notice gives:

- Trip Charge = €10,499
- SND (current 2010/11 rates) = €7,860

13 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2013

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2013. This includes the deduction of any revenues obtained from Infra-marginal Rent or Ancillary Services.

Cost Item	Northern Ireland Distillate
Annualised Cost per kW	€86.23/kW
Ancillary Services	€4.32/kW
Infra-marginal Rent	€5.54/kW
BNE Cost per kW	**€76.37/kW**

Table 13.1 – *Final costs for BNE Peaker for 2013*

14 CAPACITY REQUIREMENT FOR 2013

14.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2013 is the same as that used in previous years' calculations. This section details the individual components and calculations that have been carried out for the quantification of the 2013 Capacity Requirement.

As in previous years the RAs will revisit the demand forecasts with the TSOs for the decision process if there is any need to change the forecasts based on the most up to date information.

14.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

The Capacity Requirement quantification process was consulted on in August 2006 under 'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism' (AIP/SEM/111/06). This was a comprehensive consultation which took place following an initial consultation on the CPM in March 2006 entitled 'The Capacity Payment Mechanism and Associated Input Parameters' (AIP/SEM/15/06).

A Decision Paper was published in February 2007 which set out the RAs' decisions on the contents of the August 2006 Consultation Paper. This Decision Paper laid out the key methodology and individual data point assumptions. These parameters were used in calculating the 2007, 2008, 2009, 2010 and 2011 Capacity Requirement.

14.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2012

As anticipated in the initial consultation and decision papers, the same parameter settings have been used in the calculation for the 2012 Capacity Requirement. The following sections describe further each of these parameters.

14.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours Loss of Load Expectation per annum. The GSS of 8 hours has been retained by RAs for the 2013 calculation.

14.3.2 DEMAND FORECAST

Considering the recent changes in demand as a result of the economic downturn, the RAs have worked closely with both TSOs in determining a suitable forecast for 2013. Recent demand trends and economic forecasts were also used in the analysis.

As a result, the forecasted demand, used in the Capacity Requirement Calculation for each jurisdiction was determined to be as follows:

	2012 Forecasted Total Energy Requirement	2013 Forecasted Total Energy Requirement
Republic of Ireland	27,336	27,846
Northern Ireland	9,360	9,476

Table 14.1 – *Forecasted Total Energy Requirement*

For the purposes of calculating the Capacity Requirement, the forecast was taken from the medium table of the Eirgrid / SONI forecast in APPENDIX 1 – DEMAND FORECAST. Backup information can be found in Chapter 2 of the Eirgrid/SONI All-island Generation Capacity Statement 2012-2021[29].

This demand forecast will be recalculated before the final decision on the capacity requirement.

[29] http://www.soni.ltd.uk/upload/All-Island%20GCS%202012-2021.pdf

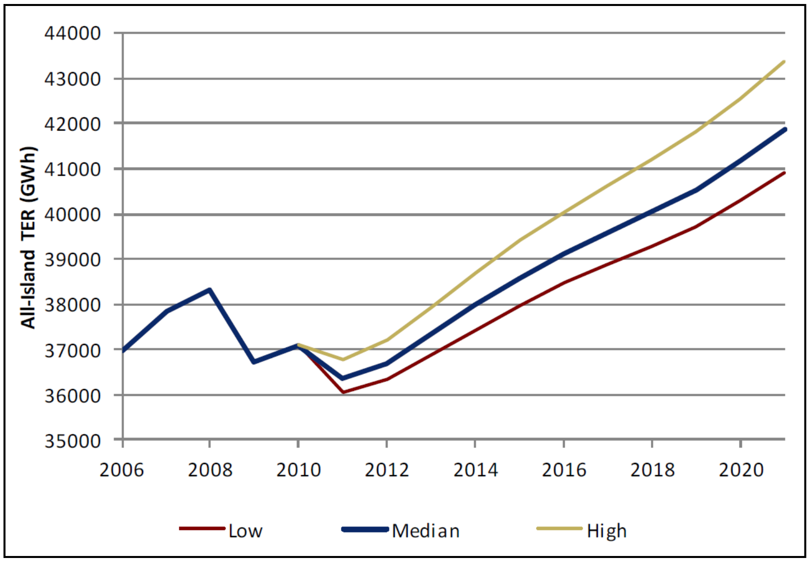

Figure 14.1 – *All-Island Demand Forecast*[30]*.*

As stated above the Eirgrid/SONI Median Demand forecast was used to calculate the Capacity Requirement. Figure 14.1 shows a return to 2008 demand levels is not observed until after 2014.

The RAs have reviewed several economic commentary publications to determine a suitable forecast for 2013. Historically there has been a reasonable correlation between economic growth and increases in electricity demand. Previous demand forecasts have been made based on economic forecasts by economists such as the Economic and Social Research Institute (ESRI). It has been stated that the correlation between economic growth and electricity demand has changed as growth in the economy has transitioned to less energy intensive sectors; this continues to hold, as on-going concerns surrounding the debt crisis in the euro-zone will cause a fluid level of uncertainty towards future forecasting.

On 24 February 2012 the ESRI issued its "Winter 2011/Spring 2012 Quarterly Economic Commentary"[31]. Some of the main findings of their analysis include the following: Irish GDP growing by about 0.9% in real terms in 2011 and is expected to remain at this level in 2012, before increasing to 2.3% in 2013. Unemployment will remain high at around 14%.

[30] Chart obtained from Eirgrid/SONI - Page 19 - All-island Generation Capacity Statement 2012-2021

[31] http://www.esri.ie/irish_economy/quarterly_economic_commen/latest_quarterly_economic/

The "Ulster Bank Irish Economic Outlook[32]" published in August 2011 stated that the Irish economy remains on track for a return to positive GDP growth, but deterioration in global outlook dampens recovery momentum.

The Northern Bank/Oxford Economics Quarterly Sectoral Forecast (26 January 2012)[33] estimates that the Northern Ireland economy contracted by 0.2% in Quarter 4 and remained flat over the year 2011. The forecasts suggest very modest growth for Northern Ireland in 2012 of 0.3%. Although recovery is projected to gather pace into 2013 and 2014, this is predicated on improved financial conditions across the developed world and Europe in particular

The PWC Northern Ireland Economic Outlook, March 2012[34] stated that the most likely scenario for Northern Ireland in 2012 is for a modest and very weak recovery, reflecting the very subdued state of the region's two main external markets – the rest of the UK and the Republic of Ireland. The impact of UK public spending reductions and further spending constraints in Northern Ireland are likely to be more keenly felt in 2012 than in 2011.

The Demand forecast not only takes into account economic conditions but also looks at historical yearly load shape and typical weather patterns. Considering the unprecedented times and the concerns surrounding the debt crisis in the euro-zone, the RAs are minded to revisit the demand forecasts with the TSOs to ensure that they still reflect the actual demand trend. This activity will take place during the early summer of 2012 ahead of any final decision on the Capacity Requirement for 2013.

For the 2013 Capacity Requirement calculation, the TSOs were asked to provide half-hourly demand forecast profiles. Care was exercised to ensure that the jurisdictional traces were harmonised and day-shifted to align on a day-by-day basis. The Sent-Out Load Trace is forecasted from the base year 2007 and using the forecasted growths from the latest Generation Capacity Statement 2012-2021 and the Wind Forecast for 2013 is forecasted from the base year 2009. The RAs assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the ADCAL calculation engine (described below).

[32] http://www.ulsterbankcapitalmarkets.com/home/Economist/RoI%20Economics%202/RoI%20Quarterly%20Economic%20Update2.aspx

[33] http://www.northernbank.co.uk/SiteCollectionDocuments/economic/2012/quarterly-sectoral-forecast-q1-2012.pdf

[34] http://pwc.blogs.com/northern-ireland/2012/03/ni-economic-outlook-march-2012.html

14.3.3 GENERATION CAPACITY

Similar to the previous years' Capacity Requirement calculations, the generation capacity data was already collected as part of the Directed Contracts process that took place in 2011. As such this data was sourced from the Directed Contracts database, with discussion with TSOs as needed in supplement. For the Decision paper the RAs will use the 2012-13 Validated Directed Contracts database that is currently being processed.

14.3.4 SCHEDULED OUTAGES

In the Decision Paper AIP/SEM/07/13 it was decided that scheduled outages for thermal plant would be quantified based on the previous five years of unit set data, and that the ADCAL algorithm would be permitted to efficiently schedule these outages during the calendar year. This process has continued to be applied in formulating the scheduled outage inputs for each unit in the 2013 Capacity Requirement process.

14.3.5 FORCED OUTAGE PROBABILITIES

The Decision Paper AIP/SEM/07/13 sets out the RAs decision to set a target for Forced Outage Probabilities (FOP) to incentivise an improvement in plant performance above the historical levels. This value was calculated based on the observed improvements in plant performance following privatisation of the Northern Ireland portfolio in the 1990s and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) clarifies that the computed value was to be used in calculations going forward.

As described in Section 4 above and in the Decision Paper on the CPM Medium Term review, the SEM Committee have decided to amend the FOP to 5.91% for the 2013 BNE Calculation.

14.3.6 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explains the RAs' decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2013 process. Individual wind output traces were provided by the TSOs. The wind traces were built upon the same reference year and aligned on a day-by-day basis with the load traces described earlier.

14.3.7 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2013 Capacity Requirement.

The ADCAL process has been described in AIP/SEM/111/06 and the subsequent decision to employ a 'perfect plant' method detailed in the Decision Paper AIP/SEM/07/13. The process is discussed in more detail below.

Once the input data has been assembled, the Capacity Requirement quantification process involves the following steps:

1. Use ADCAL to calculate the Loss of Load Expectation (LOLE) for 2013 that arises from the conventional market capacity, employed to meet the 2013 load trace with wind output netted from this trace.

2. Assuming this LOLE is below the target of 8 hours, add incremental block loads ('perfect plant') to the load trace and recalculate the LOLE.

3. Repeat Step 2 until the LOLE is exactly 8 hours for the year.

4. Note the quantity of block load used to obtain the 8 hour LOLE (referred to as BLOAD).

5. If in surplus, build a 'reference plant' with statistics based on the stack of generators (averaged capacity, SOD etc.).

6. Add this plant to the stack and use ADCAL to re-calculate LOLE, the LOLE will again decrease below the 8 hour mark.

7. Add some additional block load until the 8 hours is once again achieved. Note the amount of additional block load used in this step above the original BLOAD.

8. Divide the Capacity of the Reference plant by calculated in step 7 above. This represents the ratio of imperfect-to-perfect plant.

9. Multiply the ratio in step 8 by the original perfect surplus in step 4. This is the imperfect surplus.

10. Deduct the imperfect surplus from the total installed capacity used in Step 1, this is the conventional requirement.

11. Calculate the all-island Wind Capacity Credit based on the credit curve methodology used in the Generation Adequacy Report and the assumed installed capacity of Wind on the island.

12. Add the Wind Capacity Credit to the Step 10 conventional requirement; this is the final Capacity Requirement.

14.4 PROPOSED CAPACITY REQUIREMENT FOR 2013

The inputs used in the 2013 consultation calculations are summarised below.

Input	Description
Load Forecasts for ROI and NI for 2012	A combined load forecast for 2013, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The period used for analysis was 1 January 2013 to 31 December 2013. Two traces were agreed: 1) Total Load Forecast for 2013 2) Total (In Market) Conventional Load Forecast See Appendix 5 – Load Forecast for 2013
Generation Capacity	A list of all generation to be in place in 2013 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2013, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). Dublin Waste to Energy and Nore OCGT were not included in the model. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9,995MW** See Appendix 6 – Generation Capacity for 2013
Wind Capacity Credit (WCC)	The most recent available Wind Capacity Credit (WCC) curve (produced by the TSOs) is used to assess the total WCC for the combined total wind installed. The Average WCC is calculated for the total installed wind. This average WCC is then applied to the time weighted total capacity for the Wind in the Market The Time Weighted Total Wind in 2013 used was **2,442MW**. This results in a Capacity Credit of **0.159**. The Time Weighted Market Wind Capacity in 2013 was **1,885MW**. Therefore the Wind Capacity Credit is derived as **300MW** (1885 x 0.159)

	See Appendix 7 – Wind Capacity in 2013 See Appendix 8 – Wind Capacity Credit (WCC) curve
Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the 5 year average of scheduled outages for each unit. See Appendix 9 – Average SOD for 2013
Force Outage Probability (FOP)	In line with the SEM Committee decision on the CPM Medium Term Review, the FOP has been changed from 4.23% to 5.91%.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 14.1 – *Summary of Inputs into Adcal Model*

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2013 is **6,923MW.**

The Proposed Capacity Requirement for 2013 is 6,923MW

15 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2013

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement as detailed above, the Annual Capacity Payments Sum (ACPS) for 2013 is proposed to be €528.71m. The proposed figures are detailed in table 15.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2013	76.37	6,923	528,709,510

Table 15.1 – ACPS for the Trading Year 2013

The Proposed Annual Capacity Payments Sum (ACPS) for 2013 is €528.71M

16 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to Kenny Dane at kenny.dane@uregni.gov.uk by **5pm on 12 June 2012**.

The SEMC intends to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential together with an explanation as to why the section should be treated as confidential.

APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS

The annualised fixed cost of the BNE Peaker is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for previous the Trading Years are detailed in Table A1.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2007	64.73	6,960	450,517,348
2008	79.77	7,211	575,221,470
2009	87.12	7,356	640,854,720
2010	80.74	6,826	551,133,375
2011	78.73	6,922	544,956,545
2012	76.34	6,918	528,120,120

Table A1.1 – ACPS for Previous Trading Years

APPENDIX 2 – COMPARISON WITH 2011 BNE PEAKING PLANT

The table below shows a comparison of the costs for the 2012 and 2013 BNE Peaker Calculations.

Table A2.1 – Comparison of Costs for the 2012 and 2013 BNE Peaker

Investment Costs	2012 Decision	2013 Consultation	Variance	% Variance	
EPC Costs	87,672,370	92,500,000	4,827,630	5.51%	EPC Costs have been modelled using the latest February 2012 release of GT PRO Version 22. The BEAMA cost index gives an indication that costs over the last 12 months have increased by approximately 2%. The addition of unpredictable sources of power generation such as wind power has increased developers' interests away from large CCGT plant toward smaller simple cycle plant, so the cost of simple cycle plant may rise at a higher rate than CCGTs, particularly with aero-derivative GTs.
Site Procurement	1,439,000	1,529,154	90,154	6.27%	The site remains unchanged from last year. Site procurement costs are the same in nominal terms, but the observed variance is because of the change in the exchange rate over the last 12 months.
Electrical connection Costs	7,720,000	7,870,000	150,000	1.94%	A 2% increase in connection costs has been assumed to reflect recent movements in metal prices.
Water connection	0	0	0	0.00%	No change
Gas connection	0	0	0	0.00%	No change
Owners Contingency	4,558,963	4,810,000	251,037	5.51%	This has been set as a proportion of EPC costs based on previous experience.
Financing Costs	1,753,447	1,850,000	96,553	5.51%	This has been set as a proportion of EPC costs based on previous experience.
IDC	1,960,840	2,204,216	243,376	12.41%	This is a combination of increased EPC costs and increased borrowing costs.
Construction Insurance	789,051	832,500	43,449	5.51%	This has been set as a proportion of EPC costs based on previous experience.

Initial Fuel working capital	4,720,127	5,044,812	324,685	6.88%	Increase in Initial Fuel Working capital is associated with the change in the Oil Price. In the 2012 Decision paper the price of oil was $119/barrel and the exchange rate was approx. 0.706$/€. For the 2013 calculation, the price of oil was $123/barrel with an exchange rate of approx. 0.75$/€.
Other non EPC Costs	7,890,513	8,325,000	434,487	5.51%	This has been set as a proportion of EPC costs based on previous experience.
Accession & Participation Fees	3,903	3,903	0	0.00%	No change
Total	118,508,214	124,969,585	6,461,371	5.45%	Overall the Capital costs for the BNE peaker has increased by 6%. This is mainly due to the increase in EPC costs and the fact that some of the other costs are calculated as a % of the EPC Costs and the increase in Oil Price in comparison to the 2012 calculation.

Recurring Costs	2011 Decision	2012 Consultation	Variance	% Variance	
Transmission & Market operator charges	671,420	1,168,105	496,685	73.98%	These costs are derived directly from the published tariffs for 2011/2012.
Gas Transmission Charges	0	0	0	0.00%	No change
Operation and maintenance costs	1,791,000	1,902,000	111,000	6.20%	The fixed LTSA maintenance costs have increased by over 7%
Insurance	1,402,758	1,480,000	77,242	5.51%	Based on a percentage of EPC costs
Business Rates	626,027	695,082	69,055	11.03%	The reason for this increase is due to a combination of increased business rates, increased capacity of the BNE and movement in exchange rate
Fuel working capital (ongoing)	302,662	325,523	22,861	7.55%	Driven by changes in underlying fuel prices and in the WACC
Total	4,793,867	5,570,710	776,843	16.20%	

Cost Summary (000's)	2012 Decision	2013 Consultation	Variance	% Variance
Investment Cost (excl Fuel Working Capital)	113,788	119,925	6,137	5.39%
Initial Working Capital (including Fuel)	7,077	7,637	560	7.91%
Residual Value for Land & Fuel	-1,777	-1,882	-105	5.94%
Total Capital Costs	119,088	125,679	6,591	5.53%
WACC	6.41%	6.46%	0.04%	0.62%
Plant Life (years)	20	20		
Annualised Capex	10,733	11,481	630	5.87%
Recurring Cost	4,794	5,571	777	16.20%
Total Annual Cost	15,527	17,051	1,407	9.06%
Capacity (MW)	192.5	196.5	4.0	2.06%
Annualised Cost per kW	80.66	86.23	5.57	6.91%

APPENDIX 3 – LOW/MEDIUM/HIGH DEMAND FORECAST

Median	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2011	27,096	-2.0	9,268	Δ%	36,363	Δ%	4,736	Δ%	1,805	Δ%	6,504	Δ%	4,626	Δ%	1,715	Δ%	6,304	Δ%
2012	27,336	0.9	9,360	1.0	36,696	0.9	4,771	0.7	1,822	1.0	6,556	0.8	4,653	0.6	1,731	1.0	6,348	0.7
2013	27,846	1.9	9,476	1.2	37,323	1.7	4,850	1.7	1,844	1.2	6,657	1.5	4,726	1.6	1,753	1.2	6,441	1.5
2014	28,359	1.8	9,617	1.5	37,977	1.8	4,931	1.7	1,871	1.4	6,763	1.6	4,799	1.5	1,779	1.5	6,540	1.5
2015	28,819	1.6	9,760	1.5	38,579	1.6	5,002	1.5	1,898	1.5	6,861	1.5	4,863	1.3	1,806	1.5	6,630	1.4
2016	29,219	1.4	9,906	1.5	39,125	1.4	5,064	1.2	1,925	1.5	6,950	1.3	4,918	1.1	1,833	1.5	6,711	1.2
2017	29,536	1.1	10,053	1.5	39,589	1.2	5,113	1.0	1,953	1.5	7,027	1.1	4,959	0.8	1,861	1.5	6,780	1.0
2018	29,859	1.1	10,203	1.5	40,061	1.2	5,163	1.0	1,982	1.5	7,105	1.1	5,002	0.9	1,889	1.5	6,851	1.0
2019	30,186	1.1	10,354	1.5	40,541	1.2	5,214	1.0	2,011	1.5	7,184	1.1	5,046	0.9	1,917	1.5	6,922	1.0
2020	30,668	1.6	10,508	1.5	41,176	1.6	5,290	1.4	2,040	1.5	7,288	1.5	5,114	1.4	1,946	1.5	7,019	1.4
2021	31,222	1.8	10,665	1.5	41,887	1.7	5,370	1.5	2,070	1.5	7,398	1.5	5,194	1.6	1,976	1.5	7,128	1.6

TableA3-1: Median Demand Forecast

Low	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2011	27,096	-2.0	8,960	Δ%	36,055	Δ%	4,736	Δ%	1,787	Δ%	6,486	Δ%	4,626	Δ%	1,697	Δ%	6,286	Δ%
2012	27,295	0.7	9,023	0.7	36,318	0.7	4,764	0.6	1,786	-0.1	6,513	0.4	4,647	0.4	1,695	-0.1	6,305	0.3
2013	27,764	1.7	9,104	0.9	36,868	1.5	4,835	1.5	1,792	0.4	6,590	1.2	4,711	1.4	1,701	0.4	6,374	1.1
2014	28,234	1.7	9,204	1.1	37,438	1.5	4,907	1.5	1,806	0.8	6,676	1.3	4,775	1.4	1,715	0.8	6,452	1.2
2015	28,649	1.5	9,323	1.3	37,972	1.4	4,970	1.3	1,829	1.3	6,761	1.3	4,831	1.2	1,737	1.3	6,530	1.2
2016	29,018	1.3	9,443	1.3	38,462	1.3	5,026	1.1	1,852	1.3	6,840	1.2	4,880	1.0	1,760	1.3	6,601	1.1
2017	29,304	1.0	9,566	1.3	38,870	1.1	5,069	0.9	1,875	1.3	6,906	1.0	4,916	0.7	1,783	1.3	6,659	0.9
2018	29,595	1.0	9,689	1.3	39,284	1.1	5,114	0.9	1,899	1.3	6,973	1.0	4,952	0.7	1,806	1.3	6,719	0.9
2019	29,890	1.0	9,814	1.3	39,704	1.1	5,158	0.9	1,923	1.3	7,041	1.0	4,990	0.8	1,829	1.3	6,779	0.9
2020	30,337	1.5	9,941	1.3	40,278	1.4	5,227	1.3	1,947	1.3	7,134	1.3	5,051	1.2	1,853	1.3	6,864	1.3
2021	30,855	1.7	10,070	1.3	40,925	1.6	5,300	1.4	1,971	1.3	7,230	1.4	5,124	1.4	1,877	1.3	6,960	1.4

Table A3-2: Low Demand Forecast

High	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
Year	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2011	27,165	Δ%	9,604	Δ%	36,768	Δ%	4,747	Δ%	1,823	Δ%	6,533	Δ%	4,637	Δ%	1,732	Δ%	6,332	Δ%
2012	27,473	1.1	9,728	1.3	37,201	1.2	4,792	1.0	1,851	1.5	6,606	1.1	4,675	0.8	1,760	1.6	6,398	1.0
2013	28,055	2.1	9,891	1.7	37,946	2.0	4,882	1.9	1,881	1.6	6,725	1.8	4,757	1.8	1,790	1.7	6,509	1.7
2014	28,642	2.1	10,058	1.7	38,700	2.0	4,972	1.8	1,912	1.6	6,845	1.8	4,840	1.7	1,821	1.7	6,622	1.7
2015	29,178	1.9	10,227	1.7	39,405	1.8	5,054	1.7	1,944	1.7	6,958	1.7	4,915	1.6	1,852	1.7	6,728	1.6
2016	29,656	1.6	10,399	1.7	40,055	1.7	5,127	1.4	1,976	1.7	7,063	1.5	4,981	1.3	1,884	1.7	6,824	1.4
2017	30,052	1.3	10,574	1.7	40,626	1.4	5,187	1.2	2,009	1.7	7,155	1.3	5,034	1.1	1,916	1.7	6,909	1.2
2018	30,456	1.3	10,752	1.7	41,208	1.4	5,249	1.2	2,042	1.7	7,250	1.3	5,088	1.1	1,949	1.7	6,996	1.3
2019	30,866	1.3	10,933	1.7	41,799	1.4	5,312	1.2	2,076	1.7	7,346	1.3	5,143	1.1	1,982	1.7	7,084	1.3
2020	31,435	1.8	11,118	1.7	42,553	1.8	5,400	1.7	2,110	1.7	7,467	1.7	5,224	1.6	2,016	1.7	7,198	1.6
2021	32,082	2.1	11,305	1.7	43,387	2.0	5,492	1.7	2,145	1.7	7,594	1.7	5,316	1.8	2,051	1.7	7,324	1.8

Table A3-3 High Demand Forecast

APPENDIX 4 – CEPA'S REPORT TO RAs ON FIXED COSTS OF A BNE PEAKING PLANT FOR 2013