Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement For the Calendar Year 2012

Consultation Paper

6th May 2011

SEM-11-025

1 CONTENTS

2 INTRODUCTION

On 1 November 2007 the Single Electricity Market (SEM), the new all-island arrangements for the trading of wholesale electricity, was successfully 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) from purchasers 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 (NIAUR) 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 Regulatory Authorities reviewed these costs in relation to the determination of the value of the Annual Capacity Payment Sum for the calendar year 2008[2]. The same process was used for the calculation of the fixed costs of a BNE peaking plant for 2009, 2010, 2011 and now 2012. The consultation paper and final decision paper for 2011 were published on the AIP website[3]. The Annual Capacity Payment Sums for 2007, 2008, 2009, 2010 and 2011 are summarised in Appendix 1 of this paper.

This Consultation Paper sets out:

1. The options for the BNE peaking plant for 2012 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.

2. The proposed Capacity Requirement for 2012 and the approach used for its determination.

It has been decided that the same methodology as applied in previous years will be used in the determination of the fixed costs of a BNE peaking plant for 2012.

The RAs (in line with the 2011 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 2012.

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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=ab764619-7dee-4b19-afb2-d38b728bcfd4

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 2 introduces the consultation paper and describes the contents within;

Section 3 sets out the background to the development of the CPM;

Section 4 provides and update on the CPM Medium Term review.

Section 5 examines the technology options available in considering which generation set represents a best fit for the BNE peaking plant;

Section 6 presents the investment cost estimates for the BNE peaking plant;

Section 7 looks at the recurring costs a BNE peaking plant could expect to incur;

Section 8 considers the economic and financial parameters to be used in the evaluation;

Section 9 contains a proposal of the Best New Entrant Peaker for 2012;

Section 10 presents the Infra-marginal Rent for the chosen BNE technology;

Section 11 presents the Ancillary Service revenues calculations for the chosen BNE technology;

Section 12 provides an indicative value for the proposed BNE peaking plant fixed cost;

Section 13 details the calculation of the Capacity Requirement for 2012;

Section 14 provides an indicative value for the Annual Capacity Payment Sum for 2012 based on the proposals in this document;

Section 15 invites comments and views;

Appendix 1 summarises the Annual Capacity Payment Sum for 2007, 2008, 2009, 2010 and 2011

Appendix 2 compares the costs for the 2011 BNE Peaker and the 2012 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 2012 Calculations.

3 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 capacity payment mechanism 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 reiterated 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 Market Modelling Team based in CER. 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.

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.

[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

4 UPDATE ON THE CPM MEDIUM TERM REVIEW

4.1 BACKGROUND

On 9th March 2009 the 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 signaled 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.

4.2 CPM MEDIUM TERM REVIEW

The SEM Committee considers the CPM as a key feature of the SEM design. The SEM Committee 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 RAs have now completed four iterations of calculating the capacity pot. The SEM Committee wishes to satisfy that the correct signals and appropriate incentives or rewards 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 8th April 2009 the SEM Committee (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
- 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
- Impact on Diversity of Generation & Security of Supply

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[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

To date the RAs have published 3 consultation / discussion papers

The SEM Committee in July 2010 published a Discussion Paper on the historical aspects of the CPM Medium Term Review. 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 (Note - this consultation is still open to the end of May 2011). The paper looked at the following areas;

- 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.

As part of the investigation into the Medium term review the RAs procured consultancy support from Poyry for some aspects of the work required. Poyry produced a detailed report, which is attached in Appendix 1 of the final consultation paper, providing a number of alternative options and possible improvements to the RAs, identifying the pros and cons of the different solutions and how the recommendations meet the objectives of the CPM. The report details the performance of the current CPM design, the performance of the CPM in future years and offers options for reform.

Further details on the work packages proposed and timelines for consultation can be found on the AIP website (http://www.allislandproject.org).

4.3 NEXT STEPS

The RAs have decided on the following approach on this subject.

1. The capacity pot for 2012 will be set following the same methodology applied in establishing its value in previous years.
2. Following the inputs from final consultation paper, a decision paper on the medium term review, detailing any changes to the mechanism will be published later this year.

5 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 2012. As with the previous two years their approach remains substantively similar, their independent report is detailed in Appendix 3 of this document and is referenced throughout this paper.

5.1 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 2012.
- 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.

5.2 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 2012 has been drawn from the conclusions previously reached through the 2011 and 2010 CPM consultation process. The long list of potential options contained 27 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 aeroderivative GTs with the best specific equipment cost were also included such that the effect of any relative performance improvements from water injection or EPC cost advantages of containerised systems might be captured. 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 be commercially available

- The technology option must have a proven track-record (typically defined as 3 examples of over 8000 running hours)
- The unit sizes must be between 35 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 NOx value for distillate firing = 90Mg/Nm^3 and for gas firing = 50 Mg/Nm^3)

5.3 SHORTLIST OF TECHNOLOGY OPTIONS

Using the criteria discussed in the above section 5.2 the number of options was reduced from 27 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 -GTW Handbook. As a result of this analysis a recommended short list of options was proposed and a detailed analysis of these units was undertaken. The methodology this year was changed to increase the number of candidate plants from four to five to give a more robust analysis.

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)
- 2 x General Electric LMS100PA

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

5.4 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.

5.5 ENGINEERING, PROCUREMENT & CONSTRUCTION (EPC) ANALYSIS

Based on the short-listed technology options detailed in section 5.3, 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[8]. 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 Thermoflow yields.

It is noted there has been a slight increase in the lifetime output of a number of candidate plants in the CEPA 2012 BNE report. This is driven by requirements for greater water injection to meet IED environmental limits on NOx. Changes to average lifetime output are based on the final release of GT Pro Version 20 and consultation with 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	192.5	87.0
	Gas	193.9	87.1
1 x AE94.2	Distillate	166.4	80.5
	Gas	167.7	80.4
1 x SGT5-2000E	Distillate	166.4	80.6
	Gas	167.7	81.1
3 x SwiftPac 60	Distillate	183.8	102.8
	Gas	185.1	103.1
2 x LMS 100	Distillate	195.3	111.9
	Gas	193.5	119.0

Table 5.1 – *Summary of Proposed EPC costs for Short Listed Plants*

The increase efficiencies reflect the impact of the water injection.

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

5.6 PROPOSED TECHNOLOGY OPTION

As was used 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.

[8] 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.

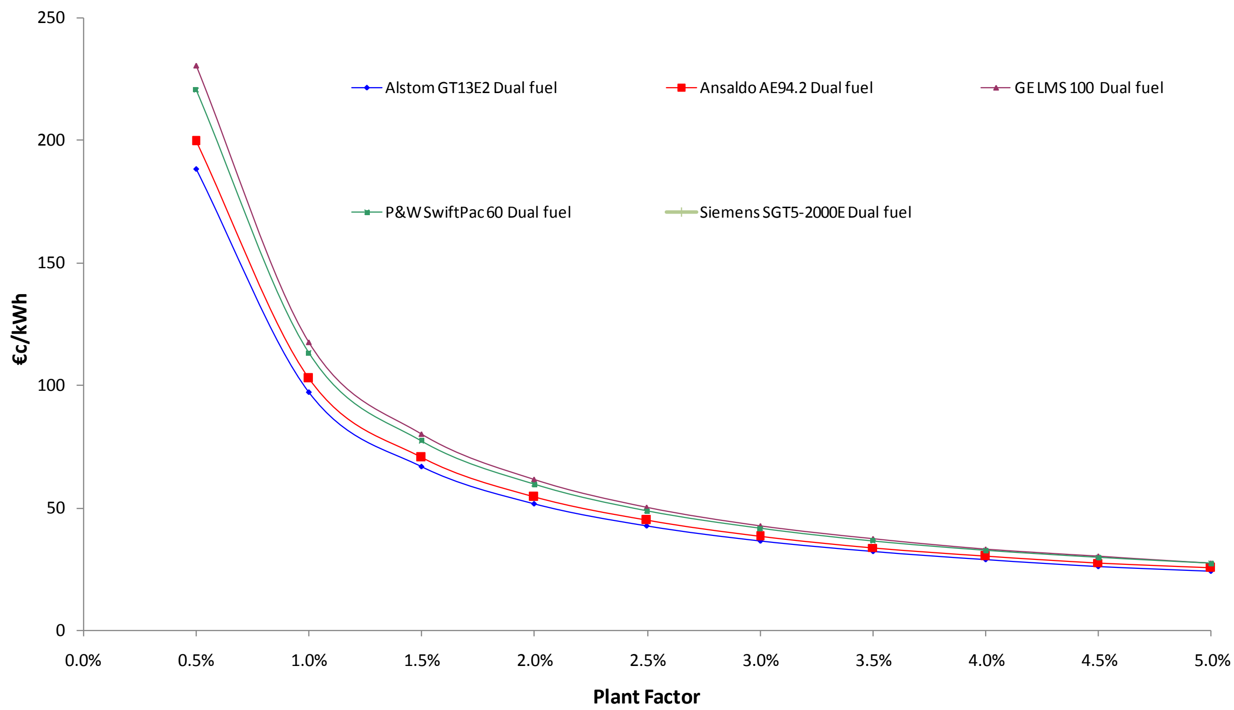

Figure 5.1 – *Screening Curve Analysis for Dual Fuel*

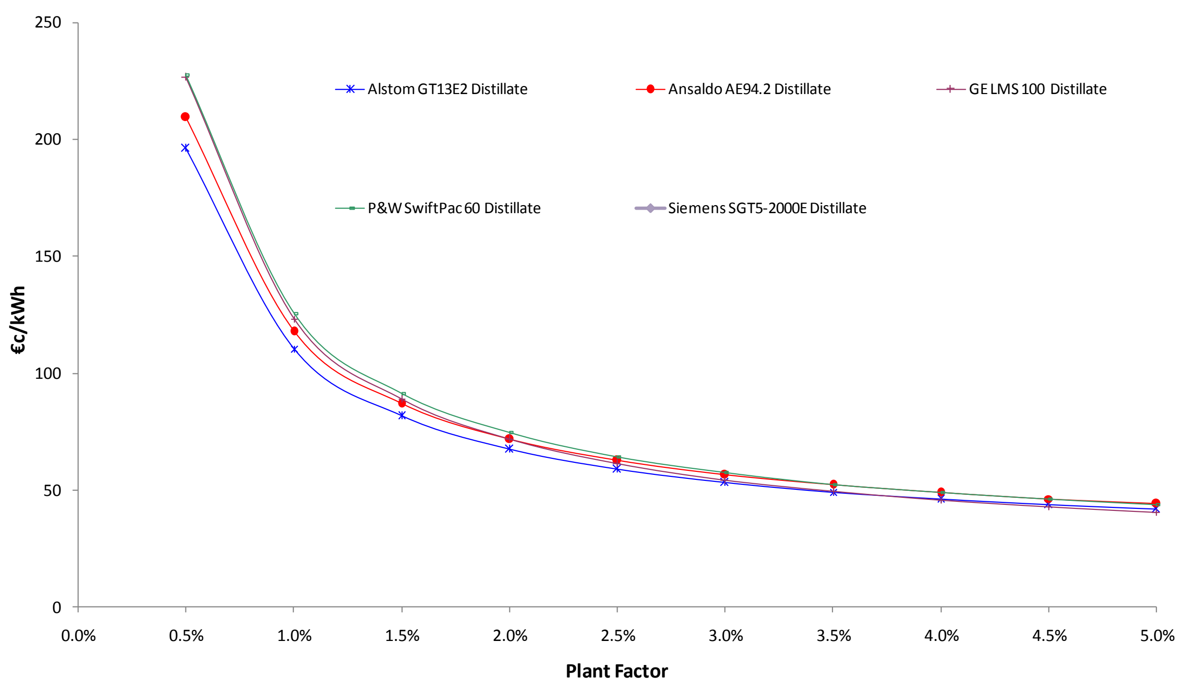

Figure 5.2 – *Screening Curve Analysis for Distillate*

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 2012 is the Alstom GT13E2. It should be noted that 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 192.5MW in distillate configuration and 193.9MW in duel fuel configuration.

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 2012 is the Alstom GT13E2

6 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 1.1351[9] on 01/04/2011. 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.

6.1 EPC COSTS

The EPC costs are covered in section 5.5 above. Table 6.1 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.

Plant Type	Location	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)
1 x Alstom GT13E2	NI	Distillate	192.5	87,037,000
		Dual	193.9	87,077,000
	RoI	Distillate	192.5	88,155,000
		Dual	193.9	88,197,000

Table 6.1 – *Summary of Proposed EPC costs for* Alstom GT13E2

6.2 SITE PROCUREMENT COSTS

[9] The exchange rate used for the assessment is £1=€1.1351 (Source: http://www.oanda.com/currency/table on Friday, April 1, 2011)

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 for a distillate plant it would be slightly larger (20,700) than a dual plant (20,500).

For Northern Ireland, the preferred option considered was the Belfast West site. This land has been cleared of the original power station and is part of the land-bank area reserved by the Utility Regulator for generation construction in the future. Following a Land bank consultation[10] on Vacant Sites within the NIE Land Bank, all sites which includes the Belfast West site will be 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 site has been the site for the last few BNE reports.

There have been significant movements in the RoI economy over the last few years, the value of land had reduced significantly when compared with estimates used in the 2010 BNE Calculations (the land value deceased by 50% between the 2010 and 2011 BNE reports). As stated in the CEPA report, Knight Frank Ireland reported that the national average price paid for farmland in 2009 dropped by 43% compared to 2008. The National Asset Management Agency (NAMA), also noted that on average, property values across all sectors had fallen 47%.

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

> "*we are seeing agricultural land prices now stabilising after significant drops approaching 50% in the years 2008 and 2009 … it is clear from the survey that land is now beginning to sell again at auction.*" [11]

As the market is beginning to stabilize, the RAs and CEPA are proposing to maintain the notional rate of €150k/acre for 2012. We welcome respondent's views on this assumption.

These costs are detailed in the table below. Further details are available in Section 4.3.2 of the CEPA/PB report.

Location	Fuel type	Required area (m2)	Estimated site cost (€)
Northern Ireland	Distillate	20,700	1,451,532
	Dual	20,500	1,437,508
Republic of Ireland	Distillate	20,700	767,262
	Dual	20,500	759,849

Table 6.2 – *Summary of Site Procurement Costs*

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

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

6.3 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 Interconnection Cost (€)
Northern Ireland	7,720,000
Republic of Ireland	6,930,000

Table 6.3 – *Summary of Electrical Connection Costs*

6.4 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	450,000	3,620,000

Table 6.4 – *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, 4 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 NI and RoI, whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market effectively on an all-island basis. On 8th April 2011 the RAs published a Briefing Note on the High Level Work Plan on Common Arrangements for Gas (CAG)[12]. 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:

[12] http://www.allislandproject.org/en/cag_publications.aspx?year=2011&section=1

(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 1st October 2010 to 30th September 2011.[13] The postalised capacity charge for the NI transmission system is published by Bord Gais Networks, including a forecast for gas years 2011/12 to 2014/15.[14] CEPA have used the forecast NI postalised capacity charge for the 2011/12 gas year.

6.5 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 6.5.

Location	Fuel Type	Owner's Contingency Cost (€m)
Northern Ireland	Distillate	4,525,924
	Dual Fuel	4,528,004
Republic of Ireland	Distillate	4,584,060
	Dual Fuel	4,586,244

Table 6.5 – *Summary of Owners Contingency costs for* Alstom GT13E2

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

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

6.6 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 6.6.

	Total Cost for Distillate (€)	Total Cost for Duel Fuel (€)
Financing NI	1,740,740	1,741,540
Financing RoI	1,763,100	1,763,940
IDC NI	1,815,350	1,841,380
IDC RoI	3,795,276	3,911,362
Construction Insurance NI	783,333	783,693
Construction Insurance RoI	793,395	793,773

Table 6.6 *– Summary of Financing, IDC and Construction Insurance costs for Alstom GT13E2*

6.7 INITIAL FUEL WORKING CAPITAL

The Fuel Working Capital for the initial fill is another cost which has to comply with various regulatory policies. 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 €4.4m for Distillate and €3.6m for dual fuel. This is based on a requirement to run for 72 hours full load and an oil price of US$119.21/ barrel[15].

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Working Capital for Fuel (either jurisdiction)	4,413,073	3,694,292

Table 6.7 – *Summary of Fuel Working Capital*

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

[15] Oil price used was ICE Brent Crude as traded on 1st April 2011 (source Bloomberg)

6.8 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 in 2011 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	7,833,330
	Dual	7,836,930
Republic of Ireland	Distillate	7,933,950
	Dual Fuel	7,937,730

Table 6.8 – *Summary Other Non-EPC costs for Alstom* GT13E2

6.9 MARKET ACCESSION AND PARTICIPATION FEES

Similar to 2011, 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 6.9 – *Summary of Market Fees*

6.10 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	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
EPC Costs	88,197,000	88,155,000	87,077,000	87,037,000
Site Procurement	759,849	767,262	1,437,508	1,451,532
Electrical connection Costs	6,930,000	6,930,000	7,720,000	7,720,000
Water connection	450,000	450,000	0	0
Gas connection	3,620,000	0	1,810,000	0
Owners Contingency	4,586,244	4,584,060	4,528,004	4,525,924
Financing Costs	1,763,940	1,763,100	1,741,540	1,740,740
Interest During Construction	3,911,362	3,795,276	1,841,380	1,815,350
Construction Insurance	793,773	793,395	783,693	783,333
Initial Fuel working capital	3,694,292	4,413,073	3,694,292	4,413,073
Other non EPC Costs	7,937,730	7,933,950	7,836,930	7,833,330
Accession & Participation Fees	3,903	3,903	3,903	3,903
Total	**122,648,093**	**119,589,019**	**118,474,250**	**117,324,185**

Table 6.10 – *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.

7 RECURRING COSTS ESTIMATE

As well as the Investment Costs, the rational investor will 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 2012 are available ahead of a decision on the cost of the BNE Peaker for 2012, the values in the table below will be adjusted accordingly to reflect these.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	1,019,749	1,012,387	682,012	677,088
Gas Transmission Charges	1,617,371	0	902,920	0
Operation and maintenance costs	1,816,000	1,791,000	1,816,000	1,791,000
Insurance	1,411,152	1,410,480	1,393,232	1,392,592
Business Rates	1,518,278	1,507,316	636,072	631,479
Fuel working capital	354,076	422,967	231,343	276,354
Total	**7,736,626**	**6,144,150**	**5,661,579**	**4,768,513**

Table 7.1 – *Summary of Recurring Costs for BNE Peaker for 2012*

As was the case with the Investment Costs, the recurring costs for Gas are also higher than the Distillate options.

8 ECONOMIC & FINANCIAL PARAMETERS

8.1 INTRODUCTION

As with previous years, a key activity in the calculation of the BNE Peaker is the determination of WACC. CEPA/PB 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. As stated in 5.1 this is a project that will considered in the SEM in 2012. 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.

8.2 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. 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.

Table 8.1 – *Summary of Assumptions on the Nature of Investment*

8.3 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 2012. In summary, CEPA/PB recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 7.60% - 11.57% in the Republic of Ireland and 5.53% - 6.99% in the UK.

A summary of the WACC parameters provided by CEPA is detailed in table 8.2 below[16]. The 2011 WACC values have been included to allow a comparison.

	RoI			UK		
Element	**2011**	**2012 Low**	**2012 High**	**2011**	**2012 Low**	**2012 High**
Risk-free rate	2.00%	4.00%	7.00%	1.75%	1.50%	2.00%
Debt premium	2.00%	1.50%	2.00%	1.75%	1.50%	2.00%
Cost of debt	**4.00%**	**5.50%**	**9.00%**	**3.50%**	**3.00%**	**4.00%**
Risk-free rate	2.00%	4.00%	7.00%	1.75%	1.50%	2.00%
ERP	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.2	1.3	1.25	1.2	1.3
Post-tax cost of equity	**7.95%**	**9.40%**	**13.50%**	**7.70%**	**6.90%**	**8.50%**
Taxation[17]	12.50%	12.50%	12.50%	28.00%	26.00%	26.00%
Pre-tax cost of equity	**9.09%**	**10.74%**	**15.43%**	**10.70%**	**9.32%**	**11.49%**
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**6.04%**	**7.60%**	**11.57%**	**6.38%**	**5.53%**	**6.99%**

[16] CEPA 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 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 eurozone 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 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 approach.

[17] In the June Budget 2010, the government announced a reform of corporation tax, including changes to rates and allowances. The main rate of corporation tax was reduced from 28% to 27% in April 2011. The Government has also indicated that further tax reductions will occur in future years. (26% in 2012-13, 25% in 2013–14, 24% in 2014-15). The RAs are also aware of the debate ongoing about Northern Ireland having a specific corporation tax for the region.

Table 8.2 – *Summary of WACC parameters recommended by CEPA/PB*

The RAs used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2012. The values to be used are the mid point of the ranges recommended by CEPA/PB. The proposed WACC values to be used for the BNE Peaker for 2012 are detailed in Table 8.3 below.

Element	2012 RoI	2012 UK
Risk-free rate	5.50%	1.75%
Debt premium	1.75%	1.75%
Cost of debt	**7.25%**	**3.50%**
ERP	4.75%	4.75%
Equity beta	1.25	1.25
Post-tax cost of equity	**11.45%**	**7.70%**
Taxation	12.50%	26.00%
Pre-tax cost of equity	13.09%	10.41%
Gearing	60.00%	60.00%
Pre-tax WACC	**9.59%**	**6.26%**

Table 8.3 – *Proposed WACC values to be used for the BNE Peaker for 2012*

9 PROPOSED BEST NEW ENTRANT PEAKER FOR 2012

9.1 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 Alstom GT13E2 for each jurisdiction and fuel type. These are summarised in table 9.1 below.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Investment Cost (excl Fuel Working Capital	118,954	115,176	114,780	112,911
Initial Working Capital (including Fuel)	6,386	6,867	6,065	6,665
Residual Value for Land & Fuel	-714	-831	-1,523	-1,740
Total Capital Costs	**124,625**	**121,212**	**119,322**	**117,835**
WACC	9.58%	9.58%	6.26%	6.26%
Plant Life (years)	20	20	20	20
Annualised Capex	14,225	13,836	10,625	10,493
Recurring Cost	7,737	6,144	5,662	4,769
Total Annual Cost	**21,962**	**19,980**	**16,287**	**15,262**
Capacity (MW)	193.9	192.5	193.9	192.5
Annualised Cost per kW	**113.26**	**103.79**	**84.00**	**79.28**

Table 9.1 – *Annualised costs for BNE Peaker for 2012*

9.2 RECOMMENDATION FOR BEST NEW ENTRANT PEAKER FOR 2012

Based on the figures from table 9.1, the Distillate option is more economical than the Gas option and overall the Distillate plant in Northern Ireland is the preferred option.

The Proposed Best New Entrant Peaker for 2012 is the Alstom GT13E2, located in Northern Ireland and firing on Distillate fuel

10 INFRA MARGINAL RENT

In order to assess the infra marginal rent a BNE peaking plant might expect to receive from the energy market, assumptions must be 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 for 2012 replicates the process used in previous years (2007, 2008, 2009, 2010 and 2011). The approach used is to complete two plexos runs, one with the BNE peaking plant and all its true characteristics 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 was procured from the Market Modelling Group, based in CER. This model is identical to that used in the recent Directed Contracts parameter calculations. This model has been published by the RAs in 2010.

As the RAs are currently in the procedure of validating the new DC model, the current most up-to-date validated SEM Plexos model is the same model that was used in last years calculation. In this model it was observed the Alstom GT13E2 plant was not scheduled at all in any of the twenty five iterations. As there have not been many changes in demand and most of the input parameters have remained the same it is assumed that there will be zero infra-marginal rent.

Once the validated new DC model is available these input parameters will be run in the new model and the output will be available for the Decision paper.

11 ANCILLARY SERVICES

The AS rates for tariff year 2011/12 have not be developed, they will be subject of a consultation during the summer of 2011. For the calculation of the Ancillary Services (AS) for the BNE peaker for 2012, the RAs have used the criteria as documented in the Harmonised Ancillary Services & Other System Charges - 2010/2011 rates consultation[18], 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/ancillaryservices/asothersystemcharges/
- 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 2012. 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 the 2010 & 2011 calculation. The assumptions used in the Ancillary Service Calculations are:

- Unit size is 192.5MW
- Run hours is 2% (Note in pervious consultations the run hours was 5%)
- Load factor is 60%

The estimated value of Ancillary Services that the BNE peaker for 2012 would achieve is €848,333. This equates to €4.41 per kW for a 192.5MW unit. Table 11.1 shows a breakdown of the calculation used.

Cost Item	Annual Availability (Half Hour)	Annual Hourly Rate €/MWh	Annual Payment €
Primary Operating Reserve	8,760	2.22	9,724
Secondary Operating Reserve	24,002	2.13	25,563
Tertiary Operating Reserve 1	26,981	1.76	23,743
Tertiary Operating Reserve 2	26,981	0.88	11,872
Replacement Reserve Unit Synchronised	26,981	0.2	2,698
Replacement Reserve Unit De-Synchronised	3,136,518	0.51	799,812
Reactive Power (Leading)	21,024	0.13	2,733
Reactive Power (Lagging)	21,024	0.13	2,733
Total Revenue			**878,877**
Penalties			30,544
Total (after penalties allocation)			**848,333**

Table 11.1 *– Summary of Ancillary Services Costs for 2012*

[18] http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=7ca6878c-058f-4497-8967-23a9c405d302

12 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2012

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2012. This includes the deduction of any revenues obtained from Infra-marginal Rent or Ancillary Services.

Cost Item	N Ireland Distillate
Annualised Cost per kW	79.28
Ancillary Services	4.41
Infra-marginal Rent	0.00
BNE Cost per kW	**74.87**

Table 12.1 – *Final costs for BNE Peaker for 2012*

It is noted that this is a decrease of 4.9% from the BNE Cost per kW for 2011.

13 CAPACITY REQUIREMENT FOR 2012

13.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2012 is the same as that used in previous year's calculations. This section details the individual components and calculations that have been carried out for the quantification of the 2012 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.

13.2 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 Capacity Payments Mechanism 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.

13.3 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.

13.3.1 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 decided upon during the early part of 2007 following this research has been retained by RAs for the 2012 calculation.

13.3.2 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 2012. Recent demand trends and economic forecasts were also used in the analysis.

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

	2011 Forecasted Total Energy Requirement	2012 Forecasted Total Energy Requirement
Republic of Ireland	0.4%	1.7%
Northern Ireland	-0.4%	0.8%

Table 13.1 – *Forecasted Demand of 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 3 – LOW/MEDIUM/HIGH DEMAND FORECAST. There is an increase of 2% in 2012 as it is assumed that the economy will recover by 2012. It should also be noted that the growth in demand is partly offset by introduction of the new interconnector which has a higher availability than a traditional conventional plant. Backup information can be found in the Eirgrid/SONI Joint All-island Generation Capacity Statement 2011-2020 report in Chapter 2.

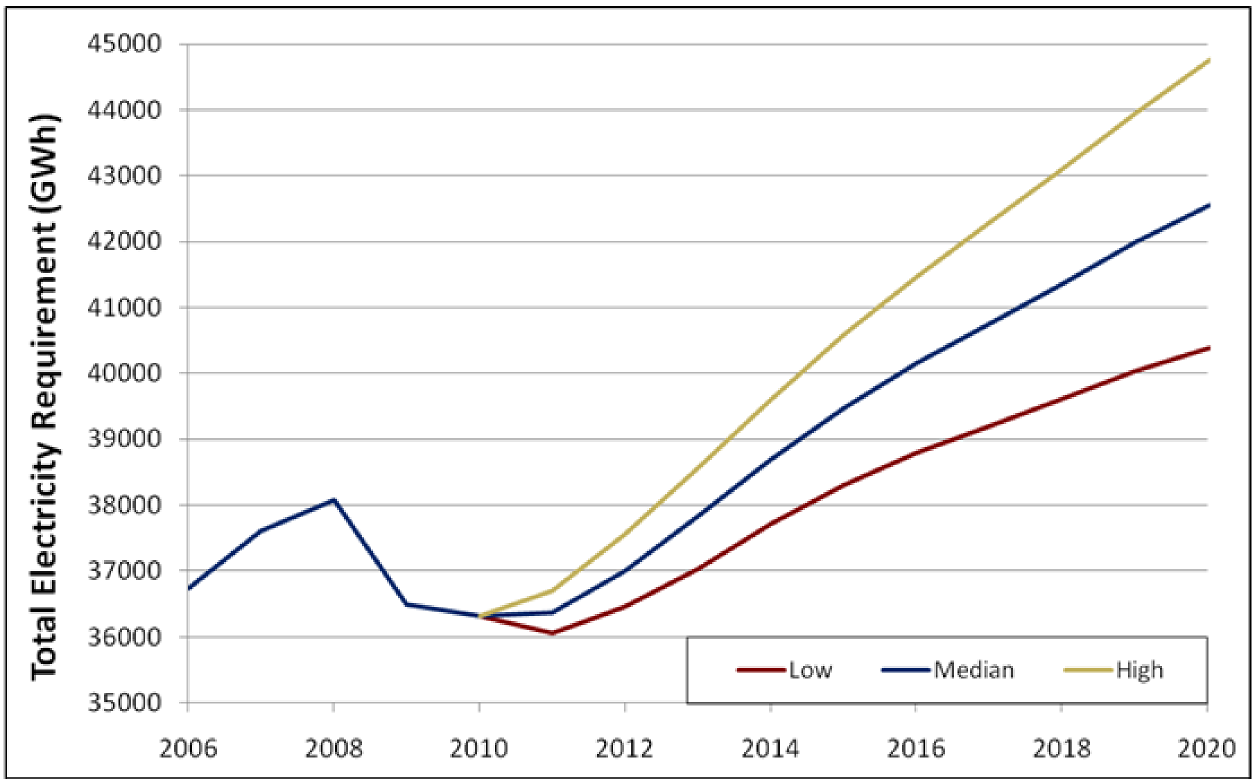

Figure 13.1 - *Demand Forecasts for the island of Ireland. Northern Ireland Forecasts were provided by SONI.*[19]

As stated the Eirgrid/SONI Median Demand forecast was used, Figure 13.1 shows a return to 2008 demand levels is not observed until 2013.

[19] Chart obtain from Eirgrid/SONI - Page 19 - All-island Generation Capacity Statement 2011-2020 (http://www.eirgrid.com/media/GCS%202011-2020%20as%20published%2022%20Dec.pdf)

The RAs have reviewed several economic commentary publications to determine a suitable forecast for 2012. 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 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 eurozone will cause a fluid level of uncertainty towards future forecasting.

On the 20/01/2011 the ESRI (The Economic and Social Research Institute) issued its "Winter 2010" Quarterly Economic Commentary.[20] Some of the main findings of their analysis include the following: GDP growing by 1 ½ per cent in real terms in 2011 and by 2 ¼ per cent in 2012. The corresponding figures for GNP are ¼ per cent in 2011 and 1 ½ per cent in 2012. They highlight that on-going uncertainty with respect to job stability; wages and taxation are likely to act against any rebound in consumption spending over the forecast horizon.

In the "First Trust Bank Economic Outlook & Business Review, Dec 2010[21]" stated that the Republic Of Ireland Economy is emerging from a recession which has been broad based and the biggest fall in output has been seen in fixed investment as a result of the sharp contraction in construction activity. The performance of manufacturing industry in NI is following the pattern set in previous recoveries that is, lagging 3 to 4 months behind the recovery in Great Britain (GB). In the light of the upcoming reduction in public expenditure, it is difficult to foresee anything but further retrenchment in the service sector. It also stated that NI is not immune to the consequences of the austerity plan now in place in the RoI economy.

The "Ulster Bank ROI Quarterly Review[22]" published in August 2010 stated that a host of indicators point to an economy that turned a corner in the first half of this year…but a continuation of the export-led Irish recovery is critically dependent on the international outlook, where downside risks have risen lately. The Ulster Bank NI Quarterly Economic Update[23] published in June also stated that the state of the public finances is the primary concern in the euro zone, UK and NI and NI's long term economic performance is still lagging UK. A host of indicators point to an economy that turned a corner in the first half of this year…but a continuation of the export-led Irish recovery is critically dependent on the international outlook, where downside risks have risen lately.

The Northern Bank/Oxford Economics Quarterly Sectoral Forecast report (Jan-2011)[24] estimates that the local NI economy grew by 0.9% q/q in Quarter 4 and by 1.3% over the year 2010. The overall growth pattern for Northern Ireland remains unbalanced with recovery coming to some sectors (namely Agriculture, Manufacturing, Distribution and Hospitality) while other sectors continue to contract. In particular, the Construction sector has

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

[21] http://www.firsttrustbank.co.uk/servlet/BlobServer?blobkey=id&blobwhere=1044897680707&blobcol=urlfile&blobtable=FTB_Download&blobheader=application/pdf&blobheadername1=Content-Disposition&blobheadervalue1=document.pdf

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

[23] http://www.ulsterbankcapitalmarkets.com/home/Economist/NI%20Economics%202/NI%20Quarterly%20Economic%20Update%202.aspx

[24] http://www.northernbank.co.uk/SiteCollectionDocuments/economic/2011/q12011-sector-forecast.pdf

suffered more acutely than elsewhere in the UK as a result of the collapse in the local housing market. In 2011 overall growth in the NI economy is expected to remain fragile, in particular quarterly growth in the first three months of 2011 for Northern Ireland is forecast to be less than 0.5 percent due to weak consumer confidence and the introduction of higher VAT.

The PWC NI Economic Outlook; December 2010[25] also stated that Northern Ireland is likely to continue to lag behind the UK average, with output growth of about 1% in 2010 and 1.7% in 2011. This will not be enough to prevent further increases in unemployment. In the short term, the impact of the VAT increase will impact the economy but this is likely to be less than the alternative of other tax increases or further spending cuts.

These recent economic forecasts show that their predictions in these quarterly updates remain cautious. Ireland's economy has shifted considerably in the last few years, with the economy expected to recover slowly, the economic backdrop will remain difficult over 2011 and slowly recover as the global economy swings upwards.

The Irish Government also published their National Recovery Plan 2011-2014[26] which sets out in detail the measures that will be taken to put public finances in order. It identifies the areas of economic activity which will provide growth and employment in the next phase of Irish economic development. The Plan provides a blueprint for a return to sustainable growth in the Irish economy. It outlines the measures that will be taken to put the Irish public finances in order and it also specifies the reforms that the Government will implement to promote growth in output and employment in the next phase of Irish economic development. Within this document it stated that the Irish economy experienced an extremely sharp downturn over the period 2008-2009. This reflected three main factors: (1) the most severe global recession since the Second World War; (2) the correction in the domestic construction sector; and (3) the rapid deterioration in consumer and business confidence. In overall terms, real GDP fell by nearly 11% over this period, while the fall in real GNP was even larger at almost 14%. The former compares with a contraction of around 3% for the OECD as a whole. However within this plan they stated that the Irish economy now appears to be coming out of this exceptionally deep and prolonged recession.

The Central Statistics office published a report on March 2011[27] showing an annual rate of inflation of 3 %, this jump of inflation could mean that the pace of improvement in Ireland's competitiveness is slowing down.

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 eurozone, 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 2011 ahead of any final decision on the Capacity Requirement for 2012.

[25] http://www.pwc.co.uk/ni/publications/nieo_dec_2010.html

[26] http://www.finance.gov.ie/documents/publications/other/2011/natrecplanlatest.pdf

[27] http://www.cso.ie/releasespublications/documents/prices/current/cpi.pdf

For the 2012 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 2011-2020 and the Wind Forecast for 2012 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).

13.3.3 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 early 2010. 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 validated Directed Contracts that is currently being processed.

13.3.4 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 5 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 2012 Capacity Requirement process.

13.3.5 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 1990's and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) makes it very clear that the computed value was to be used in calculations going forward. The RAs have carried this figure forward in its quantification of the 2012 Capacity Requirement. The RAs note that in general over the past year the system availability has improved which suggests an improvement in the FOP rates. The Moyle Interconnector had cable fault on Pole 1 from 09/09/2010 to 18/11/2010 and was unavailable. As the Moyle FOP is based on historical data the RAs wish to include this event in the calculation of the Moyle FOP. The AdCal Model was also run with this data excluded from the historical data to see the effect on the final proposed Capacity Requirement.

13.3.6 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 2012 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.

13.3.7 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2012 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 2012 that arises from the conventional market capacity, employed to meet the 2012 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.

13.4 PROPOSED CAPACITY REQUIREMENT FOR 2012

The inputs used in the 2012 consultation calculations are summarised below. The associated data sets are attached as appendices to this paper.

Input	Description
Load Forecasts for ROI and NI for 2012	A combined load forecast for 2012, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The period used for analysis was 1 January 2012 to 29th December 2012 as the AdCal model uses a 364 day sample. Two traces were agreed: 1) Total Load Forecast for 2012 2) Total (In Market) Conventional Load Forecast See Appendix 5 – Load Forecast for 2012
Generation Capacity	A list of all generation to be in place in 2012 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2012, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). Dublin and Meath Waste to Energy and Nore OCGT were not included in the model. Also Northwall 4 is unavailable. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9537MW** See Appendix 6 – Generation Capacity for 2012
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 2012 used was **2,839**MW. This results in a Capacity Credit of **0.147**. The Time Weighted Market Wind Capacity in 2012 was **2,288**MW. Therefore the Wind Capacity Credit is derived as 336**MW** (2,288 x 0.147) See Appendix 7 – Wind Capacity in 2012 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 2012
Force Outage Probability (FOP)	In line with previous years, the RAs maintained the value of **4.23%** for the FOP. It should be noted that an FOP of 1.431% was used for the Moyle Interconnector, based on historical data which includes the data for cable fault on Pole 1 from 09/09/2010 to 18/11/2010. If the data for cable fault on Pole 1 was excluded from the Moyle historical analysis it would have a FOP of 0.158%.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 13.1 – *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 2012 is **6,942MW.**

It is noted that this is an increase of 0.29% from the Capacity Requirement for 2011.

If the FOP for Moyle which excluded the data for cable fault on Pole 1 was used in the AdCal calculation then the 2012 proposed Capacity Requirement would be 6918 MW a -0.06% from the Capacity Requirement for 2011.

The Proposed Capacity Requirement for 2012 is 6,942MW

14 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2012

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2012 as detailed in Sections 12 and 13 above, the Annual Capacity Payments Sum (ACPS) for 2012 is proposed to be €519.78. The proposed figures are detailed in table 14.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2012	74.87	6,942	519,777,576

Table 14.1 – ACPS for the Trading Year 2012

It is noted that this is a decrease of 4.62% from the ACPS for 2011.

The Proposed Annual Capacity Payments Sum (ACPS) for 2012 is €519.78M

15 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 both Jody O'Boyle at jody.o'boyle@niaur.gov.uk and Clive Bowers at cbowers@cer.ie by **5pm on 10th June 2011**.

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.

16 APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR 2007, 2008, 2009, 2010 & 2011

The annualised fixed cost of the BNE Peaker is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for the Trading Years 2007, 2008, 2009, 2010 and 2011 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

Table A1.1 – ACPS for the Trading Years 2007, 2008, 2009, 2010 and 2011

17 APPENDIX 2 – COMPARISON WITH 2011 BNE PEAKING PLANT

The table below shows a comparison of the costs for the 2011 and 2012 BNE Peaker Calculations.

Comparison of Costs for 2011 and 2012 BNE Peaker Calculations	2011 Decision	2012 Consultation	Variance	% Variance	Comment
<u>Site Procurement</u>	1,507,768	1,451,532	-56,236	-3.73%	The site remains unchanged from last year and the RAs are satisfied that the estimate for 2011 is an reasonable reflection of the current costs. The slight change in site procurement costs is driven by the change in land size (the change in the exchange rate also has an effect) – the land size number is fractionally different in the rounding from last year based on the latest GT Pro information (the size is slightly higher for distillate from last year while dual fuel is slightly lower).
<u>Post Financial Close Costs</u> **EPC Total**	91,009,000	87,037,000	-3,972,000	-4.36%	EPC costs are using latest version of GT Pro, which includes costs submitted from suppliers. Note the Distillate Facilities and Water Injection costs are included in the 2012 EPC Contract costs. PB has noticed a fall in prices in projects they have recently been involved with. This is supported by the cost estimates from the post-September 2010 GT Pro Version 20.
<u>Electrical Interconnection</u>	7,492,999	7,720,000	227,001	3.03%	The figures for 2012 show a slight increase from 2011 and are as a result of discussions with the TSOs and are therefore deemed as accurate. The estimates are the same as was used last year for the decision paper but have been slightly updated based on a view of the increase in input prices.
Owners Contingency	4,732,468	4,525,924	-206,544	-4.36%	There is an decrease in the level of contingency recommended but this is reflective in the decrease in the EPC cost
Financing Costs	1,820,180	1,740,740	-79,440	-4.36%	This cost has been calculated as a % of the EPC costs for 2012 resulting in a lower figure.

Comparison of Costs for 2011 and 2012 BNE Peaker Calculations	2011 Decision	2012 Consultation	Variance	% Variance	Comment
Interest During Construction	1,880,171	1,815,350	-64,821	-3.45%	This cost is largely in line with the costs estimated in 2011.
Construction Insurance	1,456,144	1,392,592	-63,552	-4.36%	Construction Insurance – is a proportion of EPC Costs
Initial Fuel working capital	3,395,256	4,413,073	1,017,817	29.98%	Increase in Initial Fuel Working capital has been associated with the increase in the Oil Price - 2011 Decision paper was US$76.32/barrel and the for 2011 consultation paper it is US$87.57/barrel. For this paper it was US$119.21/barrel.
Accession & Participation Fees	3,915	3,903	-12	-0.31%	Accession & Participation Fees have decreased from previous years, the latest charge is taken from the SEMO Revenue and Tariffs for October 2010 – September 2011
Other non EPC Costs	8,190,810	7,833,330	-357,480	-4.36%	Other non EPC Costs
TOTAL INVESTMENT COST	117,456	112,911	-4,545	-3.87%	The overall investment cost for 2012 is lower than the costs for 2011, mainly due to the change in the EPC estimate.
Land & Fuel Residual Value	-1,424	-1,740	-316	22.2%	An adjustment had been made in 2011 to account for the residual value of the Land and Fuel.
Initial Working Capital	5,329	6,665	1,336	25.06%	An estimate was made of the initial working capital required. This includes the initial fuel required.
TOTAL ADJUSTED INVESTMENT COST	**120,851,648**	**117,324,185**	**-3,527,463**	**-2.92%**	Overall the Capital costs for the BNE peaker has decreased by 2.92%. This is mainly due to the decrease 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 2011 calculation.

Comparison of Costs for 2011 and 2012 BNE Peaker Calculations	2011 Decision	2012 Consultation	Variance	% Variance	Comment
Capital Cost					
Capex	121,361	117,835	-3,526	-2.91%	
Plant life (Years)	20	20	0	0%	No Change
WACC (%)	6.38%	6.26%	-0.11%	-1.79%	The WACC has been reduced by 1.79%. See Annex 2 in the CEPA report. This also includes the NI Corporation Tax reduction from the 2011 decision paper.
Other Costs					
Operations and Maintenance	1,791,000	1,791,000	0	0.00%	No Change
Transmission and SEMO charges	800,682	677,088	-123,594	-15.44%	These costs are derived directly from the published tariffs for 2010/2011.
Insurance and Miscellaneous cost	1,456,144	1,392,592	-63,552	-4.36%	This cost has been calculated as a % of the EPC costs for 2011
Rates cost	633,741	631,479	-2,262	-0.36%	The same assumptions from 2011 were used in 2012 for calculating rates.
Fuel Working Capital	216,482	276,354	59,872	27.66%	Increase due to variance in the fuel price at an increase US$119.21/barrel.
Total Costs	4,898,049	4,768,513	-129,536	-2.64%	**The overall estimate for these costs for 2012 is slightly lower than in 2011**

Comparison of Costs for 2011 and 2012 BNE Peaker Calculations	2011 Decision	2012 Consultation	Variance	% Variance	Comment
Annualised Capital plus Fixed Costs (€/kW)	83.14	79.28	-4	-4.64%	
Energy Market Infra Marginal Rent	0	0	0	0%	No change
Ancillary Service Revenue	4.41	4.41	0	0%	The AS Costs has remained the same from the Decision in 2011 it will be reviewed with the AS rates for tariff year 2011/12 in the summer consultation
Plant Output	190.10	192.50	2	1.26%	The increase is driven by a change in the emissions limit for some of the units (they need to inject more water to meet environmental limits (i.e. NOx limits)) – this results in higher power output for the plants but also higher equipment costs. Changes to average lifetime output are based on the final release of GT Pro Version 20 and consultation with plant manufacturers.
Capacity Requirement	6922	6942	20	0.29%	
Final BNE Cost	**78.730**	**74.87**	**-3.86**	**-4.90%**	**The Final BNE Cost for 2012 is lower, mainly due to the fall in the EPC Costs.**

Table A2.1 – Comparison of Costs for the 2011 and 2012 BNE Peaker

18 APPENDIX 3 – LOW/MEDIUM/HIGH DEMAND FORECAST

Median

Year	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,602	Δ%	1,738	Δ%	6,308	Δ%
2011	27,345	0.4	9,029	-0.4	36,374	0.2	4,722	0.1	1,688	-2.9	6,380	-0.6	4,604	0.0	1,688	-2.9	6,262	-0.7
2012	27,897	2.0	9,103	0.8	37,000	1.7	4,810	1.9	1,707	1.1	6,486	1.7	4,687	1.8	1,707	1.1	6,363	1.6
2013	28,589	2.5	9,239	1.5	37,828	2.2	4,924	2.4	1,729	1.3	6,622	2.1	4,796	2.3	1,729	1.3	6,494	2.1
2014	29,302	2.5	9,378	1.5	38,680	2.3	5,041	2.4	1,755	1.5	6,764	2.1	4,908	2.3	1,755	1.5	6,631	2.1
2015	29,946	2.2	9,518	1.5	39,464	2.0	5,146	2.1	1,781	1.5	6,895	1.9	5,008	2.0	1,781	1.5	6,757	1.9
2016	30,485	1.8	9,661	1.5	40,146	1.7	5,233	1.7	1,807	1.5	7,007	1.6	5,089	1.6	1,807	1.5	6,864	1.6
2017	30,942	1.5	9,806	1.5	40,748	1.5	5,305	1.4	1,834	1.5	7,106	1.4	5,156	1.3	1,834	1.5	6,957	1.4
2018	31,407	1.5	9,953	1.5	41,360	1.5	5,378	1.4	1,862	1.5	7,206	1.4	5,224	1.3	1,862	1.5	7,052	1.4
2019	31,878	1.5	10,102	1.5	41,980	1.5	5,453	1.4	1,889	1.5	7,308	1.4	5,293	1.3	1,889	1.5	7,149	1.4
2020	32,292	1.3	10,254	1.5	42,546	1.3	5,517	1.2	1,917	1.5	7,399	1.2	5,353	1.1	1,917	1.5	7,235	1.2

Low

Year	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,580	Δ%	1,738	Δ%	6,308	Δ%
2011	27,209	-0.1	8,846	-2.4	36,055	-0.7	4,697	-0.4	1,670	-3.9	6,336	-1.3	4,638	1.3	1,670	-3.9	6,218	-1.4
2012	27,621	1.5	8,828	-0.2	36,449	1.1	4,761	1.4	1,674	0.2	6,403	1.1	4,721	1.8	1,674	0.2	6,280	1.0
2013	28,169	2.0	8,870	0.5	37,039	1.6	4,849	1.8	1,684	0.6	6,501	1.5	4,806	1.8	1,684	0.6	6,373	1.5
2014	28,730	2.0	8,977	1.2	37,707	1.8	4,940	1.9	1,698	0.8	6,606	1.6	4,879	1.5	1,698	0.8	6,473	1.6
2015	29,219	1.7	9,084	1.2	38,303	1.6	5,017	1.6	1,718	1.2	6,703	1.5	4,932	1.1	1,718	1.2	6,565	1.4
2016	29,598	1.3	9,193	1.2	38,791	1.3	5,075	1.2	1,738	1.2	6,780	1.1	4,970	0.8	1,738	1.2	6,637	1.1
2017	29,894	1.0	9,304	1.2	39,198	1.0	5,119	0.9	1,759	1.2	6,845	1.0	5,009	0.8	1,759	1.2	6,696	0.9
2018	30,193	1.0	9,415	1.2	39,608	1.0	5,163	0.9	1,780	1.2	6,910	0.9	5,049	0.8	1,780	1.2	6,756	0.9
2019	30,495	1.0	9,528	1.2	40,023	1.0	5,208	0.9	1,801	1.2	6,975	0.9	5,079	0.6	1,801	1.2	6,816	0.9
2020	30,739	0.8	9,643	1.2	40,382	0.9	5,243	0.7	1,822	1.2	7,031	0.8	5,092	0.3	1,822	1.2	6,867	0.7

High

Year	TER (GWh)						TER Peak (MW)						Transmission Peak (MW)					
	Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island		Ireland		Northern Ireland		All-island	
2010	27,249	Δ%	9,067	Δ%	36,316	Δ%	4,715	Δ%	1,738	Δ%	6,421	Δ%	4,628	Δ%	1,738	Δ%	6,308	Δ%
2011	27,481	0.9	9,213	1.6	36,694	1.0	4,746	0.7	1,705	-1.9	6,421	0.0	4,737	2.3	1,705	-1.9	6,303	-0.1
2012	28,173	2.5	9,379	1.8	37,552	2.3	4,860	2.4	1,737	1.9	6,567	2.3	4,871	2.8	1,737	1.9	6,444	2.2
2013	29,013	3.0	9,548	1.8	38,561	2.7	5,000	2.9	1,768	1.8	6,737	2.6	5,011	2.9	1,768	1.8	6,609	2.6
2014	29,881	3.0	9,720	1.8	39,601	2.7	5,145	2.9	1,800	1.8	6,914	2.6	5,140	2.6	1,800	1.8	6,781	2.6
2015	30,688	2.7	9,895	1.8	40,583	2.5	5,278	2.6	1,832	1.8	7,078	2.4	5,251	2.2	1,832	1.8	6,940	2.3
2016	31,394	2.3	10,073	1.8	41,467	2.2	5,394	2.2	1,865	1.8	7,226	2.1	5,347	1.8	1,865	1.8	7,083	2.1
2017	32,022	2.0	10,254	1.8	42,276	2.0	5,496	1.9	1,899	1.8	7,362	1.9	5,446	1.9	1,899	1.8	7,213	1.8
2018	32,662	2.0	10,439	1.8	43,101	2.0	5,600	1.9	1,933	1.8	7,499	1.9	5,548	1.9	1,933	1.8	7,345	1.8
2019	33,315	2.0	10,627	1.8	43,942	2.0	5,707	1.9	1,968	1.8	7,641	1.9	5,640	1.7	1,968	1.8	7,482	1.9
2020	33,915	1.8	10,818	1.8	44,733	1.8	5,804	1.7	2,003	1.8	7,772	1.7	5,716	1.3	2,003	1.8	7,608	1.7

19 APPENDIX 4 – CEPA'S REPORT TO RAS ON FIXED COSTS OF A BNE PEAKING PLANT FOR 2012