Single Electricity Market

Fixed Cost of a Best New Entrant

Peaking Plant,

Capacity Requirement

&

Annual Capacity Payment Sum for the Calendar Year 2013

Decision Paper

31 August 2012

AIP/SEM/12/078

1 CONTENTS

1 CONTENTS 2
2 SUMMARY OF DECISIONS 6
3 CONSULTATION 10
3.1 CPM MEDIUM TERM REVIEW 10
3.2 BNE CHOICE 10
3.3 ECONOMIC AND FINANCIAL PARAMETERS 11
3.4 LOCATION 11
3.5 INFRA-MARGINAL RENT 12
3.6 ANCILLARY SERVICES 12
3.7 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2013 12
3.8 CAPACITY REQUIREMENT 12
3.9 RESPONSES 12
4 TECHNOLOGY OPTIONS 14
4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER 14
4.2 COMMENTS RECEIVED ON TECHNOLOGY OPTIONS 14
4.2.1 TECHNOLOGY CHOICE AND ENVIRONMENTAL REQUIREMENTS 14
4.2.2 GRID CODE COMPLIANCE 15
4.3 RAS' RESPONSE TO COMMENTS RECEIVED ON TECHNOLOGY OPTION 15
4.4 DECISION ON TECHNOLOGY OPTION 16
5 INVESTMENT COSTS 17
5.1 INVESTMENT COSTS FROM CONSULTATION PAPER 17
5.2 COMMENTS RECEIVED ON INVESTMENT COSTS 18
5.2.1 CONNECTION COSTS 18

5.2.2 CARBON PRICE FLOOR 18
5.2.3 OTHER COSTS 19
5.3 RAS' RESPONSE TO COMMENTS ON INVESTMENT COSTS 19
5.3.1 CONNECTION COSTS 19
5.3.2 CARBON PRICE FLOOR 21
5.3.3 OTHER COSTS 21
5.4 DECISION ON INVESTMENT COSTS 22
6 RECURRING COST ESTIMATES 23
6.1 RECURRING COSTS FROM CONSULTATION PAPER 23
6.2 COMMENTS RECEIVED ON RECURRING COST ESTIMATES 23
6.2.1 GAS TRANSPORTATION COSTS 23
6.2.2 GENERATOR TRANSMISSION USE OF SYSTEM ("**GTUOS**") CHARGE 23
6.2.3 OTHER RECURRING COST ESTIMATES 24
6.2.4 FUEL WORKING CAPITAL 24
6.3 RAS' RESPONSE TO COMMENTS ON RECURRING COSTS 24
6.3.1 GAS TRANSPORTATION COSTS 24
6.3.2 GTUOS CHARGES 24
6.3.3 RECURRING COST ESTIMATES 25
6.3.4 FUEL WOKING CAPITAL 25
6.4 DECISION ON RECURRING COST ESTIMATES 25
7 ECONOMIC AND FINANCIAL PARAMETERS 26
7.1 ECONOMIC AND FINANCIAL PARAMETERS FROM CONSULTATION 26
7.2 COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS 27
7.2.1 BLENDED WACC 27

7.2.2 WACC PARAMETERS 28

7.3 RAS' RESPONSES TO COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS 29

7.3.1 WACC PARAMETERS 29

7.3.2 SINGLE BNE COST OF CAPITAL 30

7.4 DECISION ON ECONOMIC AND FINANCIAL PARAMETERS 31

8 BEST NEW ENTRANT PEAKER FOR 2013 34

8.1 CONSULTATION PAPER 34

8.2 COMMENTS RECEIVED ON BNE PEAKER FOR 2013 34

8.2.1 PLANT LOCATION 34

8.2.2 EXCHANGE RATE RISK 35

8.3 RAS' RESPONSES TO COMMENTS RECEIVED ON BNE PEAKER 2013 35

8.3.1 PLANT LOCATION 35

8.3.2 EXCHANGE RATE 35

8.4 DECISION ON BNE PEAKER 2013 35

9 INFRA MARGINAL RENT 37

9.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER 37

9.2 COMMENTS RECEIVED ON INFRA MARGINAL RENT 37

9.3 RESPONSE TO COMMENTS RECEIVED ON INFRA MARGINAL RENT 38

9.4 DECISION ON INFRA MARGINAL RENT 39

10 ANCILLARY SERVICES 40

10.1 ANCILLARY SERVICES FROM CONSULTATION PAPER 40

10.2 COMMENTS RECEIVED ON ANCILLARY SERVICES 40

10.3 RESPONSES TO COMMENTS RECEIVED ON ANCILLARY SERVICES 40

10.4 DECISION ON ANCILLARY SERVICES 42
11 DECISION ON BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2013 45
12 CAPACITY REQUIREMENT FOR 2013 46
12.1 CAPACITY REQUIREMENT FOR 2013 FROM CONSULTATION PAPER 46
12.2 COMMENTS RECEIVED ON THE CAPACITY REQUIREMENT FOR 2013 46
12.3 RESPONSE TO COMMENTS RECEIVED CAPACITY REQUIREMENT FOR 2013 47
12.4 DECISION ON CAPACITY REQUIREMENT 2013 48
13 ANNUAL CAPACITY PAYMENT SUM FOR 2013 51
14 ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS 52

2 SUMMARY OF DECISIONS

The Best New Entrant ("**BNE**") Peaking Plant for 2013 (and the following two years) is an **Alstom GT13E2** firing on **distillate fuel**, sited in **Northern Ireland**.

The estimated annualised fixed cost, net of estimated infra-marginal rent and ancillary service revenue, is **€78.18/kW/year.**

The Capacity Requirement for 2013 is **6,778MW.**

The product of these price and quantity elements yields an Annual Capacity Payment Sum ("**ACPS**") for the 2013 Trading Year of **€529,876,722.**

When comparing the above figures to those proposed in the Consultation Paper ('*Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2013' (SEM-12-029)*)[1], the following items have been reviewed and changed in calculating the final annualised fixed cost of the BNE Peaker:

The Exchange rate and oil price have been updated to the most up-to date figures (cut off date for the model was Wednesday 4 July 2012).

The GTUoS rates used have been update to take account of the decision made by the SEM Committee on GTUoS rates for 2012/13 at the SEM Committee on 26 July 2012.

The increase in electrical connection cost was due to an update from SONI on the connection costs at the Belfast West site. This increased capital cost drove the increase in Interest During Construction ("**IDC**") Costs.

The WACC has increased from 6.41% to 6.60%

The Capacity Requirement has been updated to reflect differences in actual demand and forecasted demand, as well as updating connection dates of wind generation in Northern Ireland.

[1] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

The tables below show the changes between the Consultation Paper and the Decision Paper:

Cost Item	Consultation Paper	Decision Paper	Variance
EPC Costs	92,500,000	92,500,000	0
Site Procurement	1,529,154	1,593,476	64,322
Electrical connection Costs	7,870,000	12,099,631	4,229,631
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,810,000	4,810,000	0
Financing Costs	1,850,000	1,850,000	0
Interest During Construction	2,204,216	2,422,639	218,423
Construction Insurance	832,500	832,500	0
Initial Fuel working capital	5,044,812	4,598,637	-446,175
Other non EPC Costs	8,325,000	8,325,000	0
Accession & Participation Fees	3,903	3,903	0
Total	**124,969,585**	**129,035,786**	**4,066,201**

Table 2.1 – Comparison of Investment Costs for Alstom GT13E2 between Consultation and Decision Papers

Cost Item	Consultation Paper	Decision Paper	Variance
Transmission & Market operator charges	1,168,105	1,041,160	-126,945
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,902,000	1,902,000	0
Insurance	1,480,000	1,480,000	0
Business Rates	695,082	724,458	29,376
Fuel working capital	325,523	303,510	-22,013
Total	**5,570,710**	**5,451,129**	**-119,581**

Table 2.2 – Comparison of Recurring Costs for Alstom GT13E2 between Consultation and Decision Papers

Cost Item	Units	Consultation	Decision	Variance
Total Investment Costs	€m	119.79	124.44	4.65
Land and Residual Fuel Value	€m	-1.88	-1.72	0.16
Initial Fuel working Capital	€m	7.64	7.02	-0.62
Total Annual Costs	€m	16.93	17.32	0.39
Plant Size	MW	196.5	196.5	0
Pre Tax WACC	%	6.46	6.60	0.14
Plant Life	Years	20	20	0
Estimated BNE cost (before reductions)	**€/kW/year**	**86.23**	**88.14**	**1.91**

Table 2.3 – Comparison of Overall Costs for Alstom GT13E2 between Consultation and Decision Papers

ACPS	Consultation	Decision	Variance
Annualised Cost per kW	86.23	88.14	1.91
Ancillary Services	4.32	4.37	0.05
Infra-Marginal Rent	5.54	5.59	0.05
BNE Cost per kW	**76.37**	**78.18**	**1.81**
Capacity Requirement	6,923	6,778	-145
Annual Capacity Payment Sum (€m)	**528.71m**	**529.87m**	**1.16m**

Table 2.4 – Comparison of ACPS for 2013 between Consultation and Decision Papers

3 CONSULTATION

On 4 May 2012 the Regulatory Authorities ("**RAs**") published a consultation paper on the *'Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2013'* (SEM-12-029)[2]. The approach used in the calculation of the BNE Peaker Costs and the Capacity Requirement was the same as has been employed in previous years.

The RAs 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. CEPA and PB also assisted the RAs in the review of the responses to the consultation paper. The following sections provide a summary of the proposals within the consultation.

3.1 CPM MEDIUM TERM REVIEW

In March 2012, the SEM Committee ("**SEMC**") published the final decision paper on the CPM Medium Term Review (SEM-12-016)[3]. The decisions made are described in full within that paper; the major changes which affect the Annual Capacity Payment Sum for 2013 are also summarised here:

- The targeted Forced Outage Probability ("**FOP**") was revised from 4.23% to 5.91%;

- Infra-Marginal Rent ("**IMR**") was formerly deducted from the annual cost of the BNE using the Forecast *Plexos* Model. It will be now deducted using the following formula:

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

- The BNE will remain constant for three years.

3.2 BNE CHOICE

The proposed Technology Option for the BNE Peaker 2013 was a distillate-fired Alstom GT13E2.

[2] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

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

3.3 ECONOMIC AND FINANCIAL PARAMETERS

Taking account of recommendations from CEPA and PB, as well as Weighted Average Cost of Capital ('WACC') allowances in the NIE Transmission and Distribution Price Controls 2012 – 2017 Draft Determination[4], the RAs arrived at the following WACC proposals for the 2013 BNE Consultation.

Element	2013 RoI	2013 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 3.1 – Proposed WACC values to be used for the BNE Peaker for 2013 (Consultation)

3.4 LOCATION

Taking account of the factors above, and the Investment and Recurring costs in each jurisdiction and the Economic and Financial parameters, **Northern Ireland** was the preferred location for the Best New Entrant.

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

3.5 INFRA-MARGINAL RENT

Using the formula described in Section 3.1, it was proposed that **€5.54/kW** of Infra-Marginal Rent be deducted from the annual cost of the BNE.

3.6 ANCILLARY SERVICES

It was proposed to deduct an allowance of **€4.32/kW** for Ancillary Services from the annual cost of the BNE.

3.7 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2013

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 3.2 – Indicative costs for BNE Peaker for 2013 (Consultation)

3.8 CAPACITY REQUIREMENT

A Capacity Requirement of **6,923MW** for 2013 was proposed.

3.9 RESPONSES

The RAs received nine responses to the consultation. These are published along with this paper. Responses were received from the following parties:

- AES
- Bord Gais Energy (BG Energy)
- Bord na Móna
- Endesa Ireland
- Energia
- ESB PG
- Irish Wind Energy Association (IWEA)
- National Electricity Association of Ireland (NEAI)
- Power Procurement Business (PPB)

The responses provided were assessed and considered by the RAs and their consultants in the determination of the decisions described in this paper. In addition, discussions were held with concerned parties which also involve conference calls with the RAs' consultants.

This document includes the full calculation of the final BNE Fixed Cost, the final Capacity Requirement and the final Annual Capacity Payment Sum ("**ACPS**") for the calendar year 2013.

The 2013 Capacity Requirement has been calculated using the same methodology that has been employed in previous years. This paper also contains the data sheets used in the Adcal[5] calculation as a series of appendices.

[5] The iterative Adcal (CREEP) software is used by the TSOs to calculate the 2013 Capacity Requirement.

4 TECHNOLOGY OPTIONS

4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER

In the consultation paper (SEM-12-029) the RAs detailed the approach used in determining the technology to be used for the BNE Peaker. A long list of options (including both gas and dual fuelled units) was initially assessed using the selection criteria defined. This process resulted in a shortlist of five options. From these a screening curve analysis was completed resulting in a final proposal.

The proposed technology option for the BNE Peaker 2013 is the **Alstom GT13E2.**

4.2 COMMENTS RECEIVED ON TECHNOLOGY OPTIONS

Two respondents (BG Energy and Endesa Ireland) provided comments in relation to the technology option proposed in the consultation paper. A number of respondents welcomed the added transparency and comprehensive approach to the selection process and the inclusion of costs for both the gas and distillate fuel options. The technology section was completed in line with last year's process. The main areas where concerns were raised are:

- Technology Choice and Environmental Requirements; and
- Grid Code Compliance

The specific comments relating to these areas are discussed below.

4.2.1 TECHNOLOGY CHOICE AND ENVIRONMENTAL REQUIREMENTS

BG Energy argued that low carbon and energy efficiency issues would be taken into account by an investor when selecting the technology for the plant. They suggested that investment in fast-ramping conventional capacity is needed to support the expansion of renewables in the SEM and the selected plant's 20 minute response time is insufficient.

Endesa Ireland questioned the reasoning behind the decision that an interconnector was deemed an unsuitable technology choice for the BNE. They also suggested that the installed capacity was too large and suggested that given the expected increase in the penetration of renewables required to meet environmental targets, it would be more advantageous to have smaller units constructed in areas near wind-farms.

Endesa Ireland also noted that as the target Fixed Outage Probability is used to incentivise good practice, the characteristics of the BNE should also reflect the type of plant that the SEMC would like to see join the system.

Endesa also acknowledged that the Industrial Emissions Directive ("**IED**") does not apply to stations operating less than 500 hours, and therefore would not apply to the BNE. However, increased penetration of intermittent renewables will likely result in greater use of flexible plant such as the BNE and the unit should be future-proofed as much as possible to ensure it can meet the IED standards or at least be capable of doing so.

4.2.2 GRID CODE COMPLIANCE

Endesa question whether the selected BNE was Grid Code compliant. For the 2012 BNE an addition was made to EPC costs to cover adjustments required to ensure the BNE was Grid Code compliant. They considered that the adjustment made to EPC costs should also be applied for 2013.

If the BNE cannot meet Grid Code Requirements then the costs of ensuring compliance or the penalty for failure to comply must be deducted from the revenue received by the BNE.

4.3 RAs' RESPONSE TO COMMENTS RECEIVED ON TECHNOLOGY OPTION

Regarding the technology choice, in the process of developing the consultation document the RAs and CEPA/PB consulted with the Transmission System Operators ("**TSOs**") (SONI in Northern Ireland and EirGrid in Republic of Ireland) to discuss and agree the appropriate assessment criteria. To the extent practicable the RAs sought to ensure consistency with criteria used in previous years and to use criteria which reflected the needs of the system.

In response to BG Energy's comments, it is noted that the 20 minute start time is a technical criteria set by the TSOs. Whilst any reduction in the response time would favour aero-derivatives, the low plant factor clearly puts a higher weighting on specific cost than efficiency.

Regarding the exclusion of interconnectors from the selection process, interconnectors were considered as part of the BNE calculation for 2010. They were excluded from the long-list in that year due to uncertainties over whether they would always be available to serve the last MW of generation in all circumstances. This situation remains.

With regards to Endesa Ireland's comments on the size of the plant, the unit size was agreed with the TSOs to be 30MW to 200MW; the GT13E2 remains appropriate as it can meet the TSOs' technical criteria.

Regarding environmental requirements, on distillate the chosen plant would only be required to achieve 90mg/Nm^3 of NO_x or less. This level can be achieved when water injection in employed, which is in place to a more-than-sufficient degree for power augmentation purposes.

In terms of future-proofing, the 2012 upgrade of the GT13E2 can achieve the applicable IED limits that reduce to 50mg/Nm^3. The upgraded GT will also require less water injection for NO_x control and thus there will still be ample water supply for the selected plant for this purpose. The costs for water storage and water treatment plant are included in the EPC.

The 0.73% uplift applied in 2012 has been applied to the EPC price in the cost estimate analysis that formed part of the EPC price used in the initial analysis. This uplift has been retained.

4.4 DECISION ON TECHNOLOGY OPTION

The SEM Committee are content that a rigorous assessment has been made of the technologies available and the proposals as detailed in the consultation should be used for the BNE Peaker for 2013. Therefore the SEM Committee have decided that the BNE Peaker for 2013 is the Alstom GT13E2. The Unit output of this plant is 196.5MW.

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

5 INVESTMENT COSTS

5.1 INVESTMENT COSTS FROM CONSULTATION PAPER

Within the consultation, the key areas given consideration were:

- Engineering, Procurement & Construction (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

The table below summarises the investment costs within the consultation for the Alstom GT13E2 for each jurisdiction and for each fuel type:

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
EPC Costs	93,700,000	93,700,000	92,400,000	92,500,000
Site Procurement	759,849	767,262	1,514,379	1,529,154
Electrical connection Costs	6,680,000	6,680,000	7,870,000	7,870,000
Water connection	480,000	480,000	0	0
Gas connection	3,620,000	0	1,810,000	0
Owners Contingency	4,872,400	4,872,400	4,804,800	4,810,000
Financing Costs	1,874,000	1,874,000	1,848,000	1,850,000
Interest During Construction	3,404,774	3,305,708	2,233,493	2,204,216
Construction Insurance	843,300	843,300	831,600	832,500
Initial Fuel working capital	3,716,492	4,434,796	4,227,704	5,044,812
Other non EPC Costs	8,433,000	8,433,000	8,316,000	8,325,000
Accession & Participation Fees	3,903	3,903	3,903	3,903
Total	**128,387,718**	**125,394,369**	**125,859,879**	**124,969,585**

Table 5.1 – Summary of Investment Costs (Consultation)

5.2 COMMENTS RECEIVED ON INVESTMENT COSTS

5.2.1 CONNECTION COSTS

Electrical Connection Costs

PPB and AES noted that whilst the electrical connection costs were updated by assuming an increase in metal costs, no amendment was made to reflect the change in exchange rates when converting the cost from Sterling to Euro. Endesa Ireland considered the electrical connection costs proposed to be low relative to their experience and requested a full breakdown of assumed costs be provided.

Gas Connection Costs

PPB notes that the cost of the gas connection for the Northern Ireland unit should reflect the change in exchange rate between Sterling and Euro. They also query that the consultation paper assumes the cost of gas connection has not increased, despite inflation in labour and materials over the period.

Water Connection Costs

Endesa Ireland suggests that the setting of water connection costs for the Belfast West site to zero is inappropriate. Water connection ought to include any costs related to increasing the capacity of the water system to meet the needs of the BNE, as well as the cost of pipe maintenance. They argue that the existing pipelines will require upgrade, inspection and maintenance, which could cost more than €200,000.

5.2.2 CARBON PRICE FLOOR

Almost all the respondents highlighted that at the start of the 2013/14 financial year, a carbon floor price will be introduced in the UK; supplies of fossil fuels used in most forms of electricity generation will be charged at the relevant carbon price support rate. The carbon price floor will therefore apply to fuel costs of any BNE located in Northern Ireland, but has not been included so far in the BNE calculation.

As the BNE price will be fixed for three years, a number of respondents proposed that the three year average of published rates for 2013, 2014 and 2015 should be used in the calculation.

5.2.3 OTHER COSTS

Initial Fuel Working Capital

PPB highlights that it is incorrect that the initial fuel working capital requirements to fund the purchase of fuel stocks are set to be the same in Northern Ireland as it is in RoI. Distillate in Northern Ireland attracts Excise Duty that is payable when purchased but can be reclaimed when consumed to generate electricity. However, the Duty is a cost that must be funded, at least initially. The current rate of 11.14p/litre is scheduled to increase to 11.72p/litre from August 2012[6].

Other non-EPC costs

Endesa Ireland considers that other non-EPC costs that must be taken into account include:

- The costs of obtaining an Integrated Pollution Prevention Control ("**IPPC**") licence;
- The costs of gaining planning permission; and
- A contribution to a local 'community gain' fund, which ought to reflect that a distillate plant will have a greater impact on the local communities through emissions than would a gas plant.

Other Investment Costs

- Endesa Ireland comment that whilst the statement from the RAs' highlights that distillate storage facilities must be included for both fuel types, it is not obvious if this has actually been taken forward within the paper.

5.3 RAs' RESPONSE TO COMMENTS ON INVESTMENT COSTS

5.3.1 CONNECTION COSTS

Electrical Connection Costs

While the electrical connection quotes provided by SONI in 2009 has been updated for metal prices, an adjustment was not made in CEPA's initial report for movements in exchange rates. This has been adjusted.

[6] http://www.hmrc.gov.uk/tiin/tiin866.pdf

Within CEPA's consultation report, the breakdown of Northern Ireland electrical connection costs was based on two substations and a double circuit cable between Belfast West and Belfast Central. The cost of one substation was removed in the final estimate, as that cost was included within EPC costs. The calculation in the consultation was as follows:

£9,307,000 (two substations and a double circuit cable between Belfast West and Belfast Central);

Minus

£2,700,000 (one substation)

= £6,607,000 (total connection cost for BNE).

An updated assessment of electrical connection costs has provided by SONI:

£14,710,000 (two substations, a double circuit cable between Belfast West and Belfast Central, and connection/modelling/GC testing fees)

Minus

£5,000,000 (one substation)

£9,710,000.

Gas Connection Costs

Gas connection costs were based on Gaslink rates, priced in Euro. Gas connection costs have no impact on the BNE price as the selected (least cost) plant is distillate fired.

Water Connection Costs

The Consultation on Vacant Sites[7] document states that a water supply from the nine inch pipeline running parallel with McCaughey Road feeds the vacant Belfast West site. The off-take to the site is currently disconnected at the security gatehouse, which constitutes the battery limit of the site. The EPC cost includes the water supply pipeline from the battery limit.

The 9" header previously supplied the site with a water demand that was likely greater than the maximum demand the BNE might draw and hence no capacity-based upgrades are foreseen. An

[7] http://www.uregni.gov.uk/news/view/utility_regulator_opens_landbank_consultation/

oversized 4” raw water pipeline from the header was used as the basis for the cost estimate. In reality, since the tanks and the water treatment plant are sized for the required period of full load operation, the raw water supply line could be sized significantly smaller.

5.3.2 CARBON PRICE FLOOR

The RAs do not agree that the carbon price floor should be included within the fuel working capital calculation of the 2013 BNE calculation. It is assumed that the BNE enters the market in 2013. The fuel would therefore have been purchased before the tax comes into effect.

However, as discussed later in the paper, the RAs acknowledge that the carbon price floor should be included in the 2013 BNE Infra Marginal Rent calculation. The RAs do not agree with the responses to the consultation which suggest that the three year average of published rates for 2013, 2014 and 2015 should be used for the calculation. The fuel would be purchased during plant construction and would not be a recurring cost. The cost of the BNE plant is also being indexed to capture future movements in cost. Therefore, only the 2013/14 carbon support rate is being used.

5.3.3 OTHER COSTS

Initial Fuel Working Capital

The rate of 11.72p/litre was used in the initial report and no change has been made.

Other non-EPC costs

A broad assumption of 9% of EPC costs was allocated to other non-EPC costs. No change is proposed from the assumptions in the initial report.

Other Investment Costs

It is confirmed that distillate storage costs are included in the EPC costs.

5.4 DECISION ON INVESTMENT COSTS

Taking account of the responses received, the revised investment costs for the Alstom GT13E2 are shown below:

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
EPC Costs	93,700,000	93,700,000	92,400,000	92,500,000
Site Procurement	759,849	767,262	1,578,080	1,593,476
Electrical connection Costs	6,680,000	6,680,000	12,099,631	12,099,631
Gas connection	480,000	480,000	0	0
Water connection	3,620,000	0	1810000	0
Owners Contingency	4,872,400	4,872,400	4,804,800	4,810,000
Financing Costs	1,874,000	1,874,000	1,848,000	1,850,000
Interest During Construction	3,977,720	3,858,711	2,454,614	2,422,639
Construction Insurance	843,300	843,300	831,600	832,500
Initial Fuel working capital	3,321,015	3,962,839	3,853,839	4,598,637
Other non EPC Costs	8,433,000	8,433,000	8,316,000	8,325,000
Accession & Participation Fees	3,903	3,903	3,903	3,903
Total	**128,565,187**	**125,475,415**	**130,000,466**	**129,035,786**

Table 5.2 – Summary of Investment Costs (Decision)

6 RECURRING COST ESTIMATES

6.1 RECURRING COSTS FROM CONSULTATION PAPER

The recurring costs within the consultation paper are summarised as follows:

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	1,006,155	998,543	1,177,009	1,168,105
Gas Transmission Charges	6,080,654	0	4,055,606	0
Operation and maintenance costs	1,929,000	1,903,000	1,928,000	1,902,000
Insurance	1,499,200	1,499,200	1,478,400	1,480,000
Business Rates	1,550,069	1,538,343	700,380	695,082
Fuel working capital	315,583	376,577	272,798	325,523
Total	**12,380,661**	**6,315,663**	**9,612,193**	**5,570,710**

Table 6.1 – Summary of Recurring Costs (Consultation)

6.2 COMMENTS RECEIVED ON RECURRING COST ESTIMATES

6.2.1 GAS TRANSPORTATION COSTS

PPB notes that the SEMC paper has used indicative tariffs for 2012/13 that were published with the 2010/11 tariffs. This forecast was updated in August 2011 which will be more accurate and ought to be used instead.

PPB also notes that gas consumption in 2011/12 was lower than was forecast. The estimated gas transportation charges for 2012/13 may therefore be understated.

6.2.2 GENERATOR TRANSMISSION USE OF SYSTEM ("**GTUOS**") CHARGE

Endesa Ireland queried the implications of how current all-island GTUoS rates had been applied in the calculation, and the approach of 'averaging' Northern Ireland and RoI generator charges as adopted in the CEPA/PB report. They requested that the RAs ask the TSOs to calculate actual indicative TUoS charges for the selected BNE site.

6.2.3 OTHER RECURRING COST ESTIMATES

Endesa Ireland notes that gas capacity charges for RoI are based on 2011/12 tariffs, but are labelled as 2010/11 prices in the document.

6.2.4 FUEL WORKING CAPITAL

Endesa Ireland does not agree with the assumption that the Irish fuel security standard would apply to a station in Northern Ireland. Previous indications from the review of the fuel security code in Northern Ireland were that five days of fuel stock would be required to be held by generators; some generators are currently required to hold significantly more.

6.3 RAs' RESPONSE TO COMMENTS ON RECURRING COSTS

6.3.1 GAS TRANSPORTATION COSTS

The latest published gas transportation tariffs have been used in the revised calculations. This has no impact on the BNE price as the selected (least cost) plant is distillate fired.

6.3.2 GTUoS CHARGES

It is considered beyond the scope of the BNE calculation to assess site-specific GTUoS charges for a BNE site, especially in RoI where a notional site is assumed.

Given the decision on all-island GTUoS charges made at the SEM Committee meeting on 26 July 2012, these charges have been revised in the assessment of the BNE cost. The revised GTUoS rates are shown below[8]. As in the initial report, the tariffs are derived from wind and non-wind generators located in Northern Ireland and RoI.

Location	Consultation	Decision	Change
RoI	€4.9736/kW/annum	€6.0839/kW/annum	€1.110/kW/annum
Northern Ireland	€5.8367/kW/annum	€5.1905/kW/annum	-€0.6461/kW/annum

Table 6.2 - Revised BNE GTUoS charges

[8] http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=ff172def-a284-4aa2-b7cc-782673c50f22

6.3.3 RECURRING COST ESTIMATES

The gas capacity charges for RoI were a typographical error. This has been updated.

6.3.4 FUEL WOKING CAPITAL

As noted in the consultation paper, the fuel security code in Northern Ireland is still under review. Until this has been finalised, it has been assumed that the same obligations will apply in both jurisdictions.

6.4 DECISION ON RECURRING COST ESTIMATES

Taking the comments received from respondents into account, the estimates of the recurring costs of the Alstom GT13E2 are as summarised in the following table:

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	1,226,194	1,216,905	1,049,301	1,041,352
Gas Transmission Charges	6,081,882	0	4,421,554	0
Operation and maintenance costs	1,929,000	1,903,000	1,928,000	1,902,000
Insurance	1,499,200	1,499,200	1,478,400	1,480,000
Business Rates	1,550,382	1,538,637	729,989	724,458
Fuel working capital	297,895	355,467	254,353	303,510
Total	**12,584,554**	**6,513,208**	**9,861,597**	**5,451,320**

Table 6.1 – Summary of Recurring Costs (Decision)

The Fuel Option for the BNE Peaker 2013 is Distillate

7 ECONOMIC AND FINANCIAL PARAMETERS

7.1 ECONOMIC AND FINANCIAL PARAMETERS FROM CONSULTATION

A number of assumptions were included within the consultation on the nature of the BNE investment. 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.
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 an average tenor of 10 years is assumed on the new debt.
Credit Quality	It is assumed that a BNE investor has an investment grade credit in the range BBB to A. The analysis of market data employed data for BBB grade debt which is a more conservative assumption.

Table 7.1 – BNE peaking Plant Investment Assumptions

Using these assumptions, the following Weighted Average Cost of Capital was calculated for each jurisdiction:

Element	2013 RoI	2013 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 7.2 – Cost of Capital Parameters (Consultation)

In most cases, these parameters represented the mid-points of the ranges proposed by CEPA & PB. However, the RAs took account of the risk-free rate, the debt premium and the Equity Risk Premium published within the NIE Transmission and Distribution Draft Determination[9] when setting the figures for proposal. The figures proposed fell within the range proposed by CEPA & PB.

7.2 COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS

All respondents commented on the economic and financial parameters proposed in the consultation and this area was the most commented upon. Comments received can be broadly split into two areas:

- The suitability of using a blended all-island WACC;
- The ranges that were selected and the approach used to arrive at a point estimate within the parameter ranges;

7.2.1 BLENDED WACC

All responses argued that due to the single market and regulatory regime, a rational investor would use a blended (i.e. single) Northern Ireland and Republic of Ireland WACC rather than purely one or the other. Examples of comments received include:

"A prudent investor is likely to use a blended all-island WACC rather than a UK WACC when assessing the economics of new generation in the SEM." (AES)

"Given the inseparable cross-jurisdictional (all-island) cash flows associated with a peaking plant investment in the SEM... Energia reasonably expects that the SEM Committee will duly consider and implement a single electricity market WACC for the 2013 BNE calculation." (Energia)

"Capacity payments are funded on an all-island basis and are covered by all-island credit cover arrangements. This implies that investment risk of the BNE located in Northern Ireland is as much dependent on payment and credit risk of market participants domiciled in Ireland as in Northern Ireland." (Endesa)

"A single electricity market WACC is wholly consistent with SEM design and the fundamental premise of the BNE methodology that the rate of return earned by a new entrant must be sufficient to cover the risk of entering the SEM." (IWEA)

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

> *"It is crucial that the equal risks faced by SEM participants in the North and Republic of Ireland ("ROI") are fairly reflected and adequately compensated through the market's remuneration streams... In light of the cross-jurisdictional nature of the SEM, its common market and regulatory regime and the approach a rational investor in SEM takes to assessing the cost of capital, BG Energy supports CEPA's suggested approach to achieving a blended WACC and suggests the RAs should consider such an approach."(BG Energy)*
>
> *"The SEM is an all-Ireland market and any rational investor seeking to invest in the market will view the risk of operating in the SEM as a single risk, regardless of the potential location of their generating unit." (PPB)*

AES, Energia and IWEA were critical of the fact that the only argument against using a blended WACC, highlighted in the CEPA/PB paper was that it would be a major change to the way the Annual Capacity Payment Sum is set.

7.2.2 WACC PARAMETERS

There was a selection of comments by respondents on the input parameter ranges used to calculate the BNE WACC. Market participants felt that the evidence presented in the CEPA/PB report on the WACC parameters broadly reflected the ranges witnessed in the market. However, a great deal of attention was given to how that evidence should be interpreted to arrive at point estimates as well as a discussion of new evidence on financing costs observed in the markets.

Some of the key points raised included:

- Endesa Ireland and BG Energy considered the slightly lower range for the cost of debt in Ireland compared to last year was inappropriate;
- PPB argued that the 50 bps uplift applied to the top end of the UK debt premium range (to account for a premium on Northern Ireland utility debt compared to spreads implied by generic UK corporate bonds) should be applied across the range;
- Bord na Móna concurred with the top end of the range provided for the RoI WACC but suggested the range was too wide;
- BG Energy claim that the RAs do not acknowledge the difference between investing in Northern Ireland compared to investing in the UK.

Respondents were also critical of the use of parameters from the Utility Regulator's NIE T&D price control draft determination[10], and the adoption of a debt premium of 175bps rather than the mid-point of the CEPA range as had been done in previous determinations. NIE T&D is a regulated business, the parameters were consultation proposals (rather than a final decision) and the parameters used to benchmark the BNE WACC were backward looking to reflect NIE's historic "embedded" debt, whereas the BNE was a purely forward looking Greenfield investment with no existing assets and associated financing costs.

7.3 RAs' RESPONSES TO COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS

7.3.1 WACC PARAMETERS

For Northern Ireland, the lower end of the range for the debt premium has been increased by 50bps. The top end of the range has remained unchanged as the 50bps premium was already included in the proposals within the consultation.

When this is combined with a range of 1.5% to 2.0% for the risk free rate, a range for the overall cost of debt of 3.75% to 4.75% is obtained.

The inclusion of a 50bps Northern Ireland risk premium in the debt premium reflects observed spread differentials between NIE and UK utility bonds. The inclusion of such a risk premium means that the "UK WACC" should be more properly referred to as a "NI WACC" as the risk premium relates to Northern Ireland utility debt compared to generic UK corporate bonds. All other assumptions remain unchanged.

In the case of Republic of Ireland, the risk free rate and 'crisis' risk premium ("**CRP**") proposed by the CER for BGN's price control review has been adopted, giving a range of 3.5% to 5.5%. The CER also adopted an Equity Risk Premium in the range of 4.5% to 5.0%, which is consistent with CEPA's range for the BNE calculation.

The range for the RoI debt premium has been updated by increasing the top end of the range by 25bps to ensure consistency with the range adopted for Northern Ireland. This results in a range for the all-in cost of 5.75% to 8.25%.

The revised CEPA/PB WACC parameters are shown below (the proposals included in the consultation are also included:

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

	RoI			NI		
Parameter	**Consultation**	**Updated (Low)**	**Updated (High)**	**Consultation**	**Updated (Low)**	**Updated (High)**
Risk-free Rate[11]	-	3.50%	5.50%	2%	1.50%	2.00%
Debt Premium	-	2.25%	2.75%	1.75%	2.25%	2.75%
Cost of Debt	**6.00%**	**5.75%**	**8.25%**	**3.75%**	**3.75%**	**4.75%**
Equity Risk Premium	4.75%	4.50%	5.00%	4.80%	4.50%	5.00%
Equity Beta	1.25	1.2	1.3	1.25	1.2	1.3
Post-tax Cost of Equity	**10.70%**	**8.90%**	**12.00%**	**8.00%**	**6.90%**	**8.50%**
Taxation	12.50%	12.50%	12.50%	24%	24%	24%
Pre-tax Cost of Equity	**12.23%**	**10.17%**	**13.71%**	**10.53%**	**9.08%**	**11.18%**
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**8.49%**	**7.52%**	**10.44%**	**6.46%**	**5.88%**	**7.32%**

Table 7.3 – Updated Cost of Capital Parameter Ranges (Source: CEPA)

The reduction in the top end of the range for the all-in cost of debt and cost of equity, relative to the initial report, reflects evidence of Ireland's credit conditions having eased in recent months.

7.3.2 SINGLE BNE COST OF CAPITAL

The annex on SEM WACC in the CEPA/PB report within the consultation[12] noted that as SEM capacity payments are funded on an all-island basis, it could imply that investment risk (related to market risk but also general investor perception) could be also be priced on an all-island basis due to perceived risks of investing in a market where the majority of consumers (who ultimately fund the capacity payments) are located in RoI will dominate. The majority of respondents to the consultation stated a preference for such an approach.

However, the RAs do not consider that the ranges for the BNE WACC are inconsistent with the conclusion of how a rational investor would assess an investment in a BNE peaking plant in the

[11] The RfR for RoI also includes a 'crisis' risk premium as has been adopted by the CER for BGN's price control review

[12] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

SEM. The BNE WACC ranges for Northern Ireland and Republic of Ireland include premium in the BNE WACC range to reflect the actual business risks of trading in the all-island market.

The equity beta assumption for the BNE is in the range 1.2 to 1.3. As in previous years, this is the same in each jurisdiction and reflects the underlying systematic risk faced by the BNE investor and the risks associated with a generation plant operating in a SEM involving two jurisdictions.

In the case of the WACC range for the BNE located in Northern Ireland, available market evidence has been applied on actual Northern Ireland utility bonds to form an assessment of an appropriate premium to be included in the BNE cost of debt.

7.4 DECISION ON ECONOMIC AND FINANCIAL PARAMETERS

Taking account of the comments received, the RAs have decided to continue applying a separate WACC to the cost of the BNE in each jurisdiction. There is not enough evidence to justify changing the current methodology.

The RAs have taken account of the comments received in the inappropriateness of applying the factors from the NIE T&D Draft Determination within the BNE. The mid-points of the ranges proposed by CEPA/PB have therefore been adopted.

The WACC that will apply in each jurisdiction are therefore:

Parameter	ROI	NI
Risk-free Rate	4.50%	1.75%
Debt Premium	2.50%	2.50%
Cost of Debt	**7.00%**	**4.25%**
Equity Risk Premium	4.75%	4.75%
Equity Beta	1.25	1.25
Post-tax Cost of Equity	**10.44%**	**7.69%**
Taxation	12.50%	24.00%
Pre-tax Cost of Equity	**11.93%**	**10.12%**
Gearing	60%	60%
Pre-tax WACC	**8.97%**	**6.60%**

Table 7.4 – Cost of Capital Parameters (Decision)

In relation to an all-island WACC, the RAs do not see sufficient justification to deviate from the existing methodology of calculating the total cost of constructing and operating a BNE in each jurisdiction (which the relevant WACC each jurisdiction will affect), and then choosing the least expensive option. The existing methodology already takes into account the business risk of operating in the SEM.

The equity beta of 1.25 lies within a range which reflects the underlying systematic risk faced by the BNE investor and the risks associated with a generation plant operating in a Single Electricity Market with two jurisdictions. In addition to this, the range for the BNE cost of debt in Northern Ireland is adjusted (as it has been in previous years) to include a premium over observed borrowing costs for UK utilities, based on observed market evidence on Northern Ireland utility bonds. The lower end of the Northern Ireland BNE debt range has also been increased, so that the premium relative to UK utilities applies across the range, rather than only to the top end.

One of the assumptions is 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. Should the BNE be located in Northern Ireland, the RAs will continue with their assumption that the finance would be raised by a UK company. This company is likely to borrow in Sterling and raise equity finance in the UK. Its cost of capital would therefore reflect UK capital market indicators. If one of its projects was constructing and operating a peaking plant in the SEM, the company would look at the potential earnings of such a project and the risks surrounding it, calculate the internal rate of return on this project and compare that with its cost of capital before deciding whether to proceed. As has been mentioned, the RAs have accounted for such risks by applying a premium on debt to reflect Northern Ireland utility debt as opposed to generic UK corporate bonds, while the equity beta reflects the underlying systematic risk faced by the BNE investor and the risks associated with a generation plant operating in a SEM involving two jurisdictions.

8 BEST NEW ENTRANT PEAKER FOR 2013

8.1 CONSULTATION PAPER

The summary of the annualised costs for a distillate fired Alstom GT13E2 within the consultation paper were as follows:

Cost Item	Units	NI	ROI
Total Investment Costs	€m	119.79	120.96
Land and Residual Fuel Value	€m	-1.88	-1.02
Initial Fuel working Capital	€m	7.64	6.93
Total Annual Costs	€m	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/year**	**86.23**	**100.34**

Table 8.1 – Overall Cost of a distillate fired BNE Plant in NI and RoI (Consultation)

Based on these figures, the proposed BNE peaker for 2013 was the Alstom GT13E2 located in Northern Ireland and firing on Distillate Fuel

8.2 COMMENTS RECEIVED ON BNE PEAKER FOR 2013

8.2.1 PLANT LOCATION

Endesa Ireland was the only respondent to mention at length the issue of plant location. Their comments included:

- All of the conventional generators that have signed connection agreements are located in ROI. This suggests investors are taking into consideration additional issues when selecting the location of their plant;
- A particular site is chosen in Northern Ireland but not RoI. Actual site(s) in RoI with all the necessary consents should be selected when estimating costs for the BNE.
- Under the timeframe for development of landbank sites, the proposed site would not be available to a BNE generator for development in 2013.

- As the land would be leased, Endesa Ireland is dubious that there would be land residual value as proposed in the paper.

8.2.2 EXCHANGE RATE RISK

AES and PPB commented that the decision in the CPM Medium Term Review to fix the BNE price for three years (the aim of which is to increase stability into the Annual Capacity Payment Sum) could actually increase the volatility of CPM revenues for generators based in Northern Ireland. Both proposed fixing the Annual Capacity Exchange Rate for a corresponding three year period.

8.3 RAs' RESPONSES TO COMMENTS RECEIVED ON BNE PEAKER 2013

8.3.1 PLANT LOCATION

The RAs consider it beyond the scope of the BNE to determine specific sites for generation plant in RoI. However, where specific sites are known and been made available (such as Belfast West) these have been adopted in the analysis. The Belfast West site continues to be technically available; although an evaluation process is underway, the site hasn't yet been awarded to a specific bidder.

Regarding residual land value, land values for the Belfast West site were presented as a capital value, taking account of both commercial/industrial property land values in Belfast and the likely capitalised value of a lease. The approach taken to calculate site procurement costs means there would be a residual value that could be realised in the market.

8.3.2 EXCHANGE RATE

The RAs acknowledge the comments made on the impact of fixing the BNE price but not the Annual Capacity Exchange Rate. As part of the consultation into the Trading and Settlement Code Annual Parameters, the RAs will consult on the fixing of the Annual Capacity Exchange Rate.

8.4 DECISION ON BNE PEAKER 2013

Based on all the comments received to the consultation, the overall costs of the BNE peaker for 2013 have been reassessed. The results are shown in the table below:

Cost Item	Units	NI	ROI
Total Investment Costs	€m	124.44	121.51
Land and Residual Fuel Value	€m	-1.72	-0.85
Initial Working Capital (inc. Fuel)	€m	7.02	6.33
Total Annual Costs	€m	17.32	20.39
Plant Size	MW	196.5	196.5
Pre Tax WACC	%	6.60	8.49
Plant Life	Years	20	20
Estimated BNE cost (before reductions)	**€/kW/year**	**88.14**	**103.79**

Table 8.2 – Overall Costs of a Distillate Fired BNE in NI and ROI (Decision)

Based on the above figures, it remains more economical to locate the BNE in Northern Ireland than in Republic of Ireland.

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

9 INFRA MARGINAL RENT

9.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER

The approach to the derivation of the estimated infra-marginal rent deduction for the BNE peaker in all previous years was to utilise the most up to date validated *Plexos* model. 25 full year half hourly simulations of the SEM were run, in which forced outage patterns were randomly generated from one iteration to the next to give a spread of system margin scenarios across the year. It was observed the selected BNE was not scheduled at all in any of the 25 iterations and therefore no infra-marginal rent was deducted.

However, as a result of the CPM Medium Term Review, the methodology for calculating the infra-marginal rent was changed. Infra-marginal rent will now be deducted from the BNE using the following formula:

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

The RAs used the average bid price, in Euro, of all existing Distillate units in the SEM on 31 March 2012 (the same date as was taken for other parameters such as exchange rate and commodity prices) as a proxy for the bid price of the BNE. This bid price consisted of an average of No Load and Price-Quantity pairs. The resulting inputs and Infra-Marginal Rent were therefore:

Item	Value
Price Cap (€/MWh)	1000
Outage Time (Hours)	8
BID Price of Peaker (€/MWh)	264.14
FOP	5.91%

Table 9.1 – IMR Deduction Calculation Parameters (Consultation)

IMR DEDUCTED IN €/kW = [(1000 – 264.14)/1000] * OUTAGE TIME * (1 – 5.91%)

= €5.54/kW

9.2 COMMENTS RECEIVED ON INFRA MARGINAL RENT

Bord na Móna stated that their 116MW peaking plant is arguably the best proxy for the notional BNE in the SEM. The proposed deduction overstates the infra-marginal rent earned by a peaking plant.

The majority of respondents commented that the average bid price did not include start-up costs, did not include the carbon floor price and should be adjusted by an appropriate TLAF. It was also stated that start costs should be included for every trading period within the calculation.

AES and PPB also commented that the average BNE bid price should be based on the average of peaking plant in Northern Ireland only rather than on an all-island basis.

9.3 RESPONSE TO COMMENTS RECEIVED ON INFRA MARGINAL RENT

The RAs acknowledge that start costs should have been included within the original calculation. However, we do not agree with the statement that start costs should be included for each and every trading period within the eight hour period when the BNE would be scheduled to run. The RAs contend that it is reasonable to assume in the calculation for these eight hours to be consecutive and therefore only one set of start costs would be included.

The bid price has also now been updated to account for the carbon floor price for 2013; unlike the initial fuel working capital, it is assumed that Infra Marginal Rent is earned over the entire year on average.

The average distillate bid price on 4 July 2012 (the same date as other commodity prices and exchange rates used in the calculation of the BNE were taken) was calculated, based on Commercial Offer Data of distillate units in both Northern Ireland and Republic of Ireland. An uplift factor was then applied to this to take account of the difference between carbon price on 4 July and the proposed carbon floor price during 2013.

Regarding the application of TLAFs to the average bid price, the bid prices of each individual unit were TLAF adjusted when they were submitted to SEMO. The RAs consider that this adjustment is sufficient and there would be no material difference to the result in removing the TLAFs and applying an average TLAF.

The RAs consider that the average BNE bid price should continue to be calculated on the price of distillate units on an all-island basis. The purpose of using the average bid price is as a proxy for the bid price of the BNE. The location of the BNE would not have any significant impact upon this price.

9.4 DECISION ON INFRA MARGINAL RENT

The formula described above will continue to be used in the calculation of the infra-marginal rent to be deducted from the annual cost of the BNE. The inputs used in the calculation are as follows:

Item	Value
Price Cap (€/MWh)	1000
Outage Time (Hours)	8
BID Price of Peaker (€/MWh)	257.62
FOP	5.91%

Table 9.2 – IMR Deduction Calculation Parameters (Decision)

IMR DEDUCTED IN €/kW = [(1000 – 257.62)/1000] * OUTAGE TIME * (1 – 5.91%)

= €5.59/kW

Although start costs and the carbon floor price for 2013 have now been included, the price of distillate has fallen since the consultation paper was published. The infra-marginal rent to be deducted is therefore slightly higher than that proposed in the consultation.

Along with the BNE price, this will be fixed for the next three years.

10 ANCILLARY SERVICES

10.1 ANCILLARY SERVICES FROM CONSULTATION PAPER

The RAs worked closely with the TSOs in calculating the appropriate costs for Ancillary Services under the new propose criteria and formulae. The assumptions used in the AS Calculations for the consultation paper were:

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

10.2 COMMENTS RECEIVED ON ANCILLARY SERVICES

Bord na Móna were critical of the proposal in the consultation paper to carve out Ancillary Services as one component where the RAs would reserve the option to review the AS reduction within the fixed three year period, while PPB commented that fixing the AS reduction for three years would create an artificial exposure and volatility risk for Northern Ireland generators whose actual AS revenues will be exposed to the actual Euro/Sterling exchange rate.

Endesa Ireland provided a detailed response on Ancillary Services, highlighting that:

- The Short Notice Declaration charge used in the CEPA/PB paper was €40/MW. The current rate, is €70/MW;
- Endesa Ireland regards the 2% assumption of the unit's run hours as too high. In their experience of operating peaking plants in the SEM, a figure of 1% (or in reality even less than 0.5%) was more realistic;
- There was an inconsistency between the Ancillary Service calculation in CEPA/PB's 2011 report and the 2012 report as regards the range of Ancillary Services that the BNE was assumed to provide; and
- The consultation paper did not discuss an Ancillary Services Agreement ("**ASA**") with the TSO (which is required in order to receive payment for Ancillary Service provided) or the values that might be contained within it.

10.3 RESPONSES TO COMMENTS RECEIVED ON ANCILLARY SERVICES

The Short Notice Declaration calculation has been updated to reflect a €70/MW charge rate.

The 2% run hour assumption was adopted for the 2012 decision and is retained for 2013.

Regarding the points raised on the Ancillary Services Agreement, CEPA & PB adopted a modelling approach proposed and developed by the TSOs. No change has been made to this, and similar to the 2012 BNE Decision, the model used to derive the calculation has been published along with this paper.

10.4 DECISION ON ANCILLARY SERVICES

The Ancillary Service values used in the calculation are:

Parameter	Value	Unit	Source
POR	21.2	MW	SONI Minimum Function Spec for OCGTs
SOR	35.4	MW	SONI Minimum Function Spec for OCGTs
TOR1	35.4	MW	SONI Minimum Function Spec for OCGTs
TOR2	35.4	MW	SONI Minimum Function Spec for OCGTs
RR	196.5	MW	SONI Minimum Function Spec for OCGTs
Min MW for POR	19.7	MW	SONI Minimum Function Spec for OCGTs
Min MW for SOR	19.7	MW	SONI Minimum Function Spec for OCGTs
Min MW for TOR1	19.7	MW	SONI Minimum Function Spec for OCGTs
Min MW for TOR2	19.7	MW	SONI Minimum Function Spec for OCGTs
Min MW for RR	0.0	MW	SONI Minimum Function Spec for OCGTs
Reactive Power Leading	64.6	MVAr	SONI Minimum Function Spec for OCGTs
Reactive Power Lagging	147.4	MVAr	SONI Minimum Function Spec for OCGTs

Table 10.1 – Ancillary Service values for use in the BNE calculation for 2013

These values were chosen as the consultation paper recommended that the BNE be constructed in Northern Ireland and the values are outlined in the SONI Minimum Function Spec for OCGTs which can be found on SONI website[13].

Using these values in the attached model and the RA assumption of 60% load factor when running gives us the following output:

[13] http://www.soni.ltd.uk/upload/Minimum%20Function%20Specification%20(OCGT)%20Rev1%200.pdf

Parameter	Not Running [€/TP]	Running [€/TP]
POR		23.96
SOR		38.41
TOR1		31.86
TOR2		15.93
RR	51.09	7.86
Reactive Power Leading		8.40
Reactive Power Lagging		19.16
Total	**51.09**	**145.58**

Table 10.2 – Summary of Ancillary Services for 2013

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

$$(51.09 * 0.93 * 48 * 365) + (145.58 * 0.02 * 48 * 365) = €883,450$$

Penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events are also clarified. A 196.5MW direct trip and a 196.5MW SND at zero notice time gives:

- Trip charge = €10,499
- SND charge = €13,755

Parameter	Ancillary Services
Ancillary Service Payments	883,450
Trip Charge	10,499
SND	13,755
Total (Distillate, NI)	**859,195**

Table 10.3 – Annual Ancillary Service Revenues

The Model has been provided as Appendix 1.

Dividing the Total Ancillary Services revenue by the capacity of the BNE of 196.5MW results in an Ancillary Services payment of **€4.37/kW/year**.

This is deducted from the Annualised Cost of the BNE.

It was questioned within the responses to the consultation whether the Ancillary Services deduction would also be fixed for three years (along with the BNE price and the infra-marginal rent deduction).

It is the intention of the RAs to fix the Ancillary Services deduction for three years. However, if the introduction of DS3 significantly impacts the amount the BNE would earn through Ancillary Services, the RAs reserve the option to review the AS deduction within these years, if it is deemed appropriate to do so.

11 DECISION ON 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	88.14
Ancillary Services	4.37
Infra-marginal Rent	5.59
BNE Cost per kW	**78.18**

Table 11.1 – Final costs for BNE Peaker for 2013

12 CAPACITY REQUIREMENT FOR 2013

12.1 CAPACITY REQUIREMENT FOR 2013 FROM CONSULTATION PAPER

As detailed in the consultation paper, the methodology used for calculating the Capacity Requirement for 2013 is the same as that used in previous year's calculations. The RAs detailed the parameters settings used in the calculation of the Capacity Requirement. These include the Generation Security Standard, Demand Forecasts, Generator Capacity, Scheduled Outages, Forced Outage Probabilities and the treatment of wind. This paper also contains the data sheets used in the Adcal calculation as a series of appendices.

The Capacity Requirement in the Consultation Paper was 6,923MW.

12.2 COMMENTS RECEIVED ON THE CAPACITY REQUIREMENT FOR 2013

Four respondents provided comments in relation to the Capacity Requirement Calculations.

Energia contended that the calculated capacity requirement was materially and systematically understated. This was for three reasons:

1. It assumes that forced outages are completely independent events;
2. Extreme cold weather events seem to be treated as discountable outliers in peak demand projections;
3. Assumed plant availability is inappropriately projected from expected improvements.

Last year's BNE decision paper did not give any recognition to the risk of common mode failure with reference to cold weather events and computer viruses. Perhaps this reflects a misunderstanding that common mode failure is only considered a risk during extreme cold weather events. The TSOs do not seem to share the view that the risk of common mode failure or sympathetic tripping can be written off as atypical. In the Harmonised Other System Charges consultation, published by the TSOs on 3 April 2012, the following statement was included: "There were six events during the tariff year 2010-2011 where, following a large drop in load, another unit dropped significant load, causing a further reduction in frequency. These events are of serious concern…"

It should also be noted that in the All-Island Generation Capacity Statement for 2011-2020 the TSOs acknowledged that in reality it is not entirely true that forced outage probability is the same at all times and not linked to the outages of other generators (a similar point was made by PPB). It would be imprudent to continue assuming that generator forced outage probability is the same at all times and completely independent from the outage of other generators in the capacity requirement calculation; this invariably understates the capacity requirement. Energia recommend that the RAs ensure this is corrected in the probabilistic analysis carried out by EirGrid for calculating the capacity requirement this year and going forward.

Regarding cold weather events, last year's BNE decision paper suggested that extreme weather events are treated as discountable outliers in the capacity requirement calculation. Given the influence of cold weather on peak demand, this approach would be entirely inappropriate and would imprudently understate the capacity requirement.

Similar remarks were made by PPB, who highlighted that during the cold spells over the last few winters, high pressure resulted in minimal generation by all wind generators. IWEA were also concerned that last year's decision paper gives the impression that historical extreme weather events are treated as discountable outliers. Given that peak demand records are predominantly determined by cold weather rather than economic conditions this approach would overestimate generation adequacy.

In relation to assumed plant availability, Energia welcomes the recognition from the RAs that the previous FOP value used in the CPM calculation of 4.23% was overly optimistic. However, Energia maintain that the proposed 5.91% FOP value is not well founded in practice or justifiable as a target value. Energia strongly recommend the RAs consider a more realistic FOP in the range 8 – 9%. PPB also continues to disagree with the use of a target forced outage probability and believe that actual rates should be used which more accurately reflects the risk to security of supply.

Endesa Ireland asked that if there were to be any changes to the demand forecast in the early summer of 2012, such proposals should be consulted on with industry. PPB however, noted the caveats in relation to the demand forecast, and agreed that they should be reassessed closer to the date of the final decision.

PPB reiterated their concerns that the treatment of wind underestimates the true plant margin required and results in an understated Capacity Requirement.

12.3 RESPONSE TO COMMENTS RECEIVED CAPACITY REQUIREMENT FOR 2013

Regarding the Independence of Forced Outages, Sympathetic Tripping (where one generating unit fails, causing the system frequency to drop, and hence causing another unit to become unstable and trip) is a matter for System Security, not Adequacy assessment. It would not be feasible to 'gold-plate' a generation system so that situations like this never arise.

The CPM process deals with System Adequacy, which relates the existence of generation facilities as being sufficient to satisfy customer demand. It does not include system disturbances. As for common-mode failures, it is possible that more than one generating unit is affected at the same time by, for example, a computer virus or by extreme weather etc. However, it could be considered the responsibility of each generator to put in place measures to mitigate against such known risks for their own units.

The Targeted Forced Outage Probability vs. Actual Forced Outage Probability debate was covered in the CPM Medium Term Review. The SEM Committee decided that in order to incentivise generators to invest and improve the performance of their units, it was appropriate to continue with the use of a Targeted FOP.

To allow for extreme cold winters (and therefore extreme winter peaks) each year would not be prudent as every winter will not experience these conditions. For example, the winter of 2011/12 was one of the mildest winters on record in comparison to the previous winter of 2010/11 which was one of the coldest.

The agreed methodology for the treatment of wind within the Capacity Requirement Calculation is not a matter for the annual calculation, but is one for the CPM review. It should be noted that the Wind Capacity Credit curve is determined probabilistically. It is reviewed and updated each year as the installed wind capacity increases.

12.4 DECISION ON CAPACITY REQUIREMENT 2013

As stated in the consultation paper, the all-island demand forecast has been re-estimated before the final decision on the capacity requirement.

The updated demand forecast used for the Annual Capacity Payment Sum was produced by the TSOs at the request of the SEM Committee via the RAs. This demand forecast was based on the outturn for 2011 and the trends for 2012 up to the end of April.

In energy terms, when compared to the forecast used in the Generation Capacity Statement 2012-21, Republic of Ireland's forecast energy for 2013 has reduced by 2.2%. This is due to a slightly lower outturn for 2011 and no expected demand growth in 2012 as well as reduced forecasts of economic growth. For Northern Ireland, the reduction for 2013 is 5.9%, also due to a lower than expected demand at the end of 2011 and beginning of 2012, along with the continuing effects of the recession both regionally and in the UK in general.

On an all-island basis, this equates to a reduction of 3.2% for 2013 when compared to the demand forecast used in the Generation Capacity Statement 2012-21. The SEM Committee consider this to be a more realistic forecast of demand in 2013 than the forecast used for the consultation.

The only other changes were to the wind profiles in Northern Ireland and to the assumptions made around the connection dates for wind farms in Northern Ireland. This made a negligible difference to the Wind Capacity Credit figure.

As a result of these changes, the Capacity Requirement to be used in the calculation of the Annual Capacity Payment Sum 2013 is **6,778MW.** It is noted that this is a decrease of 2.02% from the Capacity Requirement from 2012 (6,918MW).

As agreed in the CPM Medium Term Review, this amount will be recalculated annually and multiplied by the BNE price (which is being fixed and indexed for three years) in order to obtain the Annual Capacity Payment Sum for the years 2014 and 2015.

The inputs used in the 2013 decision calculations are summarised below. The associated data sets are attached as appendices to this paper.

Input	Description
Load Forecasts for ROI and NI for 2013	A combined load forecast for 2013, on a half hourly basis for both jurisdictions, was agreed with the TSOs. The TSOs provided the RAs with a 52 week forecast which began on Sunday 30 December 2012 (the closest Sunday to 1 January 2013). The last day of the 52 week calendar falls on 28 December 2013. For completeness, forecasts for 29, 30 and 31 December were also included. Two traces were agreed: • Total Load Forecast for 2013 • Total (In Market) Conventional Load Forecast See Appendix 2 – 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). The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9,845MW**. See Appendix 3 – Generation Capacity for 2013.
Wind Capacity Credit	The most recent available Wind Capacity Credit curve (produced by the TSOs) is used to assess the total WCC for the combined total wind

(WCC)	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 **2,425MW**. This results in a Capacity Credit of **0.158.** The Time Weighted Market Wind Capacity in 2013 was **1,868MW**. Therefore the Wind Capacity Credit is derived as **296MW** (1,868 x 0.158) See Appendix 4 – Wind Capacity in 2013 See Appendix 5 – Wind Capacity Credit (WCC) curve
Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the five year average of scheduled outages for each unit. See Appendix 6 – Average SOD for 2013
Force Outage Probability (FOP)	In line with the decision in the CPM Medium Term review, the RAs used a value of **5.91%** for the FOP. It should be noted that a FOP of 6.30% was used for both interconnectors (Moyle and East-West). This reflects the recent outages experienced on the Moyle Interconnector and to take account of availability issues and 'teething' problems which can be experienced with new interconnectors. This may be reviewed for the 2014 ACPS calculation, using actual availability data for the East-West Interconnector, which becomes available in September 2012.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 12.1 – Summary of Inputs into Adcal Model

The Capacity Requirement for 2013 is 6,778MW

13 ANNUAL CAPACITY PAYMENT SUM FOR 2013

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2013 as detailed in Sections 11 and 12 above, the Annual Capacity Payments Sum (ACPS) for 2013 is determined to be €529.87m. The final figures are detailed in table 13.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2013	78.18	6,778	529,876,722

Table 13.1 – ACPS for the Trading Year 2013

The Annual Capacity Payments Sum (ACPS) for 2013 is €529.88m

14 ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS

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
2013	78.18	6,778	529,876,722

Table 14.1 – SEM Annual Capacity Payment Sums