Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Calendar Year 2011

Decision Paper

11th August 2010

SEM-10-053

1 CONTENTS

2 SUMMARY OF DECISIONS

The Best New Entrant (BNE) Peaking Plant for 2011 is an **Alstom GT13E2** firing on **distillate fuel**, sited in **Northern Ireland**.

The estimated annualised fixed cost, net of estimated infra-marginal energy rent and ancillary service revenue, is **€78.73/kW/year.**

The Capacity Requirement for 2011 is **6,922MW.**

The product of these price and quantity elements yields an Annual Capacity Payment Sum (ACPS) for the 2011 Trading Year of **€ 544,956,545.05**

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 2011' (SEM-10-034))[1] , the following items have been reviewed and changed in calculating the final annualised fixed cost of the BNE Peaker:

1) The Exchange rate and Oil price have been updated to the most up-to date figures.

2) The Ancillary Services Costs have been updated to reflect run hours of 2%. The appropriate estimate of the penalties likely to be faced by the BNE Peaker has been updated resulting in a reduced Ancillary Services Cost.

3) The Capacity Requirement has been updated to reflect an update to the Northern Ireland Demands Forecasts and updated connection dates of wind generation available in 2011 resulting in an increase of 20MW to 6,922MW.

The table below shows the changes between the Consultation Paper and the Decision Paper.

Cost Item	Consultation Paper	Decision Paper	Variance
EPC Costs	91,009,000	91,009,000	0
Site Procurement	1,443,247	1,507,768	64,521
Electrical connection Costs	7,492,999	7,492,999	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,732,468	4,732,468	0
Financing Costs	1,820,180	1,820,180	0
Interest During Construction	1,880,234	1,880,171	-63
Construction Insurance	819,081	819,081	0
Initial Fuel working capital	3,614,384	3,395,256	-219,128

[1] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=ab764619-7dee-4b19-afb2-d38b728bcfd4

Other non EPC Costs	8,190,810	8,190,810	0
Accession & Participation Fees	3,915	3,915	0
Total	**121,006,318**	**120,851,648**	**-154,670**
Cost Item	**Consultation Paper**	**Decision Paper**	**Variance**
Transmission & Market operator charges	767,133	800,682	33,549
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,791,000	1,791,000	0
Insurance	1,456,144	1,456,144	0
Business Rates	606,622	633,741	27,119
Fuel working capital	230,453	216,482	-13,971
Total	**4,851,352**	**4,898,049**	**46,697**
Cost Item	**Consultation Paper**	**Decision Paper**	**Variance**
Investment Cost (excl Fuel Working Capital	117,392	117,456	64
Initial Working Capital (including Fuel)	5,613	5,329	-284
Residual Value for Land & Fuel	-1,469	-1,424	45
Total Capital Costs	**121,536**	**121,361**	**-175**
WACC	6.38%	6.38%	0
Plant Life (years)	20	20	0
Annualised Capex	10,922	10,906	-16
Recurring Cost	4,851	4,898	47
Total Annual Cost	**15,773**	**15,804**	**31**
Capacity (MW)	193.6	190.1	190.1
Annualised Cost per kW	**81.47**	**83.14**	**0.16**
ACPS	**Consultation Paper**	**Decision Paper**	**Variance**
Annualised Cost per kW	81.47	83.14	1.66
Ancillary Services	4.75	4.41	-0.35
Inframarginal Rent	0	0	0
BNE Cost per kW	**76.72**	**78.73**	**2.01**

Table 2.1 – *Comparison of Costs for Alstom GT13E2 in Consultation and Decision Papers.*

3 INTRODUCTION

On 28th May 2010 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 2011' (SEM-10-034). 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 2011. CEPA and PB also assisted the RAs in the review of the responses to the consultation paper.

The RAs received 12 responses to the consultation (SEM-10-034). These are published along with this paper. Responses were received from the following parties:

- AES Kilroot
- Airtricity
- Bord Gáis Energy
- Bord Na Móna
- The Consumer Council
- Endesa Ireland
- ESB Power Generation
- Irish Business and Employers Confederation
- NIE Energy Limited, Power Procurement Business
- Premier Power Limited
- Siemens
- Viridian Power & Energy

The responses provided were fully assessed and considered by the RAs in the determination of the decisions laid out in this paper. In addition, conference calls well held with IBEC and their members with the RAs to discuss their response. These meetings were held with the RAs and their consultants in July 2010. 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 2011.

The 2011 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[2] calculation as a series of appendices.

[2] The iterative Adcal (CREEP) software is used by the TSOs to calculate the 2011 Capacity Requirement.

4 TECHNOLOGY OPTIONS

4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER

In the consultation paper (SEM-10-034) the RAs detailed the approach used in determining the technology to be used for the BNE Peaker. A long list of options was initially assessed using the selection criteria defined. This process resulted in a shortlist of 4 options. From these a screening curve analysis was completed resulting on a final proposal. The proposed technology option for the BNE Peaker 2011 is the **Alstom GT13E2.**

4.2 RESPONSES TO TECHNOLOGY OPTIONS

Four respondents 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 years process. The main areas where concerns were raised were:

- Technology Choice
- Unit Output
- Fuel Choice
- Environmental Requirements

The specific comments relating to these areas are discussed below.

4.2.1 TECHNOLOGY CHOICE

Most respondents either agreed with or did not specifically comment on the proposed choice of Technology for the 2011 BNE Peaker.

Bord Gáis Energy commented that one of the primary objectives of the CPM is to signal suitable investment in the market and that the calculation did not signal the future need for flexible and fast responding back up generation. Bord Gáis Energy further outlined that the Alstom GT13E2 would be less suitable in a system with high penetration of intermittent generation.

Endesa Ireland also considered that it was not sufficient for the BNE to meet minimum environmental standards, but rather considered that additional consideration should be given to units that would reduce total emissions on the island of Ireland. They also suggested that it would be more appropriate to base cost estimations on actual consented sites and to take an average of the individual cost components, rather than estimating costs based on a theoretical plant.

Bord na Móna agreed with the selection of a Gas Turbine engine as the chosen technology and suggested that in the future it might be appropriate to review the technology on a less frequent basis (once every 3-5 years).

Siemens commented that they considered that the SGT5 – 2000E should be competitive enough to be short listed and the shortlist of technology options had not fully considered the technical capabilities of the product. They provided additional information regarding the ISO performance figures against the figures in the Gas Turbine World 2009 GTW handbook.

4.2.2 UNIT OUTPUT

Several respondents commented on the appropriate plant output for the Alstom GT13E2 plant.

Bord na Móna commented that it would be appropriate to adjust the capacity of the plant to reflect the expected value of the capacity that would be available to meet peak demand. The respondent considered a forced outage range of 1-2% would be appropriate.

One respondent commented on the impact of plant life on output degradation. The respondent considered that the average degradation should be at least 3.5% over a 20 year lifetime.

4.2.3 FUEL CHOICE

Endesa Ireland considered that the environmental impact of the fuel type selected should have a significant weight in the decision criteria and that an investor should also consider the proposed levy on CO2 emissions. Endesa Ireland further argued that the selection of a distillate fired BNE will result in additional costs being incurred in the planning permission and Infrastructure Planning Commission (IPC) licence application processes (relating to community/political resistance) that should be taken into account in the BNE fixed cost.

4.2.4 ENVIRONMENTAL REQUIREMENTS

The Consumer Council noted that the RAs should ensure that the distillate fired plant would be consistent with the targets set out within DETI's Strategic Energy Framework and the targets in the Northern Ireland Executive's programme. It further questioned how the emission limitations within the Large Combustion Plant Directive would affect costs.

Premier Power further noted that the Industrial Emissions Directive (IED) was expected to be passed during 2010 and that the new plant NOx emission requirements would be likely to be 50mg/Nm3, rather than 120mg/Nm3, thus requiring additional emissions abatement equipment.

4.2.5 TRANSMISSION LOSS ADJUSTMENT FACTORS (TLAFS)

Several respondents highlighted the proposed changes to the Transmission Loss Adjustment Factors which would equalise the factor to 0.98 for all generators. The respondents highlighted that this would be taken into account by an investor and that the capacity of the plant should be adjusted to reflect this.

4.3 DECISION 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 & 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 relation to the arguments raised by Siemens regarding the decision not to shortlist the SGT5-2000E, the RAs note that CEPA/PB's report highlights the similarities between the Ansaldo AE94.2 and the Siemens SGT5-2000E and demonstrates (in Figure 3.2 of CEPA/PB report annexed to the consultation paper) the proximity of the likely competitiveness of the two GTs. They note that the purpose of the short listing process is to ensure that a full range of potential GTs are considered such that an appropriate BNE plant can be identified. While the RAs understand the commercial drivers for Siemens response, they do not consider that an amendment to the methodology is required.

The RAs also note the comment that the GT13E2 would be less suited in a system with high penetration of intermittent generation. In developing the criteria which were used to filter plant, CEPA/PB sought the views of the TSOs and specifically raised questions about whether criteria needed to be amended due to the increasing penetration of renewable generation. Both TSOs did not consider that there were grounds for amending the criteria.

In relation to the provision for outages, the RAs wish to clarify that the same assumptions for planned outage duration (13 days) and forced outage rate (2%) as had been used in previous years were included within the modelling for the calculation of the costs of a BNE plant in 2011.

Regarding the assumption for output degradation, the RAs consider that taking into account the stated operational hours expected (2% to 5% of the time), the assumed duration of run per start of 4 hours, the 10 Equivalent Operating Hours (EOH) penalty per start and a water injection EOH factor of 1.5, as well as an average EOH accrued over the lifetime of the plant (20 years). This value of 24,500 EOH was applied to a degradation curve for a GT13E2 in simple cycle and the resulting average lifetime power output degradation was calculated to be 2.4%. Therefore it is recommended that the value of this parameter selected for distillate operation be maintained at 2.5%.

Under the Environmental Requirements, the RA's agree that ensuring the BNE plant is compliant with relevant emissions legislation is an important determinant of plant choice. Within the criteria used to filter candidate plants, compliance with relevant environmental legislation was specifically considered as a pass/fail criterion. Even during the long-listing stage, generally only plants with known low NOx capability were selected. In many cases, the gas turbine costs for the Dry Low NOx/Emissions option is indeed more expensive than the standard combustor option (where available) and these higher costs were carried right the way through the entire process. It is therefore considered that each short listed plant would be expected to meet the requirements of relevant legislation.

The RAs recognise the uncertainty provided by potential future legal requirements on power stations. The RAs and their consultants have reviewed the latest draft of the IED and the current draft indicates a proposed NOx limit for liquid fired gas turbines of 90mg/Nm3. While the BNE plant for 2011 would theoretically have all its planning consents in place that only require a NOx limit of 120mg/Nm3, the chosen GT13E2 should be able to achieve 90mg/Nm3 on distillate with water injection without any flue gas treatment. As such, the RAs do not consider that there is compelling evidence to suggest that additional investment would be undertaken to meet these requirements.

Regarding planning costs the RAs note that Table 3.2 in the CEPA report states that the RoI requires any gas-fired plant to have dual fuel capability. For consistency, dual fuel capability was considered as a requirement for RoI and NI and hence, the costs of planning and consents with respect to distillate firing applies equally to the distillate and gas-fired options.

In response to the suggestion that in the future it might be appropriate to review the technology on a less frequent basis (once every 3-5 years), this is being considered in the Medium Term review.

Regarding the TLAF query the RAs assume that the BNE has at least an 'average' TLAF. Under uniform TLAF policy, its share of the pot will be exactly enough to cover it's fixed costs, because everyone else's capacity is multiplied by 0.98 as well, so the BNE's share of the pot will be correct. TLAFs do not need to be considered in calculating the pot size, as transmission losses are calculated at the station gate and the BNE is worked out in terms of Maximum Export Capacity.

Overall, the purpose of this exercise is to determine the costs that would be incurred by a rational investor in a new entrant peaking plant. The methodology used by the RAs and their consultants considered a full range of potential candidate plant and reduced that list using a series of criteria which were discussed and agreed with the TSOs; eventually leading to the identification of the most appropriate option. While the RAs recognise that in some cases the respondents views may differ, the RAs have not been presented with evidence to suggest that the plant choice was inappropriate.

In summary, 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 2011. Therefore the SEM Committee have decided that the BNE Peaker for 2011 is the Alstom GT13E2. The Unit output of this plant is 190.1MW

The Technology Option for the BNE Peaker 2011 is the <u>Alstom GT13E2</u>

5 INVESTMENT COSTS

5.1 INVESTMENT COSTS FROM CONSULTATION PAPER

In the consultation paper, the RAs discussed the key cost areas that make up the capital costs of the BNE Peaker. The key cost 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

5.2 RESPONSES TO INVESTMENT COSTS

Six respondents provided comments in relation to the capital costs proposed in the consultation paper. A number of respondents were broadly in agreement with the assumptions and calculations presented in the consultation paper.

The main areas where concerns were raised were:

- EPC Costs
- Site Procurement costs
- Electrical Connection costs
- Gas and Make-up Water Connection costs
- Owner's Contingency
- Up front costs for fuel working capital
- Other Costs

The specific comments relating to these areas are discussed below.

5.2.1 EPC COSTS

Bord Gáis Energy and Premier Power both questioned the decision to not to use a multiplier to adjust EPC costs (as was done in the 2010 calculation) and suggested this was an arbitrary change. Premier Power further commented that carbon steel prices had increased by over 40% and global composite stainless steel prices had increased by about 75%. They considered the unadjusted cost estimate provided by PEACE (including an approximate 5.5% uplift on last year's version of the software) to be under-valuing the EPC costs by a considerable margin.

Several respondents commented that the exchange rates used in the paper were set as of 14 April 2010 and that there had been subsequent exchange rate movements. The respondents considered the rates used where no longer reflective of future rates and that the assumption should be updated. One respondent suggested that exchange rates should be based on a fixed future date so that market participants could hedge against this risk.

5.2.2 SITE PROCUREMENT COSTS

A number of respondents offered comments regarding the cost of land for the BNE plant. AES Kilroot outlined that they understood that the Belfast West site was not vacant, but that the Belfast Harbour Commissioner has a licence with NIE to use the site. AES Kilroot suggested that the site cost should be adopted to include the cost of terminating this licence and suggested such cost could amount to £250k.

Premier Power also commented on the site procurement cost. They queried firstly if the land area required included sufficient land to allow the installation of Carbon Capture and Storage (CCS). Premier Power further suggested that it was not clear if the Belfast West site was entirely clear of all the power station foundations and ash contamination below ground. It suggested that the BNE developer would need to include provision for clearing the existing foundations as turbine manufacturers would not be likely to offer guarantees without new machine foundations.

5.2.3 ELECTRICAL CONNECTION COSTS

Several respondents commented on the electricity connection costs. Bord na Móna suggested that the connection cost in RoI would be €6.6 million based on a new 220kV substation and 4km of over head lines based on CERs approved rates. Endesa Ireland further commented that the connection costs outlined where too low and that the costs associated with metering and protection, as well as possible deep reinforcement also needs to be addressed.

One respondent also noted that the BNE calculation is based on the current TUoS charges and does not include the proposal to increase the TUoS charges by 100% potentially from October 2010. The respondent considered that any increases in TUoS later in the year should be included.

5.2.4 GAS AND MAKE-UP WATER CONNECTION COSTS

Several comments where received concerning the assumptions regarding water connection costs. AES Kilroot commented that while a water main is located in close proximity, such infrastructure in the harbour estate can be very old and may not be fit for purpose. AES Kilroot considered that it would be more prudent to assume the same water connection cost as used for the RoI site.

Endesa Ireland further considered that costs should be included to allow for the increased capacity of the water system needed to meet the needs of the power plant. In Endesa Irelands experience existing pipelines could have leaks which could require repair costs of around €200,000.

5.2.5 OWNERS CONTINGENCY

One respondent noted that a contingency of 5.2% was low given that the Belfast West site's former use as a coal fired power station with the associated uncertainties regarding ground conditions and contamination. The respondent suggested using a figure between 6.5% and 7.5% would be more appropriate. Another respondent outlined that the contingency cost was based on PB's experience without qualification and that it considered a contingency of 10% would be more appropriate.

5.2.6 INITIAL FUEL WORKING CAPITAL

Several respondents observed that distillate storage costs assumed were limited to 3 days of stocks at maximum load, rather than the 3.5 days assumed in last year's decision. In addition, one respondent noted that they did not consider it appropriate to apply the secondary fuel obligation in the RoI to the NI as the draft NI fuel security code indicates a requirement for plant to hold a minimum of 10 days of secondary stock at the full output. It also considered that the article 39 consent would place a requirement to hold 21 days of fuel in stock at 60% average load factor.

5.2.7 OTHER NON_EPC COSTS

One respondent considered that the non-EPC costs would be close to 15% of the EPC costs. The same respondent considered the investment costs where understated by about 10%.

5.3 DECISION ON INVESTMENT COSTS

In relation to the EPC Costs, the RAs are content that a rigorous assessment of these costs was carried out by the CEPA/PB and the proposed costs in the consultation paper are valid. When considering the EPC cost for the plant, the same process as last year was used.

Several respondents questioned the decision to not to use a multiplier to adjust EPC costs (as was done in the 2010 calculation), applicable recent projects, the costs and details for which cannot be divulged for reasons of confidentiality, were modelled in GT Pro to compare the new Version 20's PEACE cost estimates with the actual plant prices. This process yielded a good correlation between recent project costs and the PEACE estimates. CEPA/PB accepts that this aspect of the methodology is less transparent than would be ideal. However, on balance, they consider that benchmarking a global cost database (which can contain lags in updating prices) with relevant market evidence is an appropriate method of establishing cost estimates of a BNE plant. The RAs have scrutinised this aspect of the approach and are content that a rigorous assessment of these costs have been carried out by CEPA/PB.

The RAs agree with the responses that the most up to date information should be included for the purpose of the calculation. In light of this the assumptions for the exchange rates have been updated, as well as the oil prices to the latest available. For exchange rates, the spot rate of £1= €1.184 was sourced from www.oanda.com on 20 July 2010 looking at the 19 July 2010 (this has updated the €1.134 rate used in the consultation paper). The RAs believe that a current spot rate is preferable to using an unknown future rate, as it provides greater certainty and transparency to participants. Similarly we note that the Annual Capacity Exchange Rate is set in a later process (usually in September). Participants may of course choose to hedge their cost and revenue flows if that is efficient for them, but the RAs should not impose such a requirement.

The RAs note the comment from Bord na Móna regarding the estimates of connection costs and have updated the cost assumptions for RoI to include information from the most up to date statement. Regarding the comment about potential changes to TUoS charges, similarly to previous years the RAs have based the assumptions on the latest available information. This can be found on the TSO websites.

Regarding the water connection costs the RAs have used the same assumption as last year. It is worth noting that the cost for piping within the battery limit of the plant is included in the calculation, and the demineralisation plant has been sized for 50% of the maximum full load plant requirement, thus no more than 25t/h will ever be drawn from the existing header at Belfast West. In the Land Bank[3] consultation it indicates the old stations demineralise water treatment plant was designed to process approximately 165t/h of water. The RAs do not therefore propose to make any additional allowance for upgrading infrastructure.

In relation to the Site procurement costs, the RAs recognise that property prices have been particularly volatile over recent years. The RAs also recognise that some sites, such as those with access to an electricity, gas and water connection may, in some cases, attract a price premium. Land costs were an area which the RAs were keen to explore in detail and, as such, CEPA/PB commissioned an independent property market expert with direct experience of power project investment to advise on cost estimates. The Belfast West site has been cleared of the old power station. This is further supported by the Utility Regulators recently closed "Consultation Paper on Vacant Sites within the NIE Land Bank[3]".

Regarding the comment on space for Carbon Capture and Storage, or Carbon Capture Readiness (CCR) rather for gas/distillate fired plants, the Department of Energy and Climate Change only requires CCR for plants with a net power output of 300 MW or more.

In response to the question regarding the terms of the licence between NIE and Belfast Harbour Commissioner, the RAs consider this to be confidential between the agree parties. Regarding a breakage fee for the Belfast West site, the RAs do not consider it appropriate to apply an allowance for this. The RAs are satisfied that the quotations provided reflect the market value of the site and have decided that the costs detailed in the consultation paper reflect the market value.

The RAs can confirm that the fuel stock assumption is 3.5 days for the distillate plant, hence allowing for 0.5 days of commercial stocks in addition to the statutory strategic stock requirement. In the CEPA/PB report they explained that their calculation of the fuel stocks (as well as the opportunity cost for holding fuel) was: "…based on a requirement to run for 72 hours full load, as well as an additional 0.5 days of commercial running for distillate plants…" This equates to enough fuel to run at full capacity for 84 hours for the distillate plant.

The RAs also note the views of the respondents regarding using the most up to date information for the calculation and have updated the oil price used to use the ICE Brent price on 20 July 2010 ($76.32)[4].

---

[3] http://www.uregni.gov.uk/uploads/publications/2010-05-13_Consultation_on_Vacant_Sites_within_the_NIE_Land_Bank.pdf

[4] http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D

The RAs also note the comment regarding the potential revisions to the fuel security code in Northern Ireland, but consider that at the time of writing this report, the RAs have used the most up to date available information as these amendments have not yet been finalised.

The new initial fuel working capital is outlined in Table 5.1. The assumption also affects the ongoing opportunity cost of holding the fuel. The updated figures for opportunity cost of fuel are outlined in table 5.2.

	Days of storage	Fuel working capital (€m)
Distillate	3.5 (84 hours)	3.395
Dual Fuel	3 (72 hours)	2.914

Table 5.1- *Initial Fuel working capital*

	Ongoing fuel cost (€m)
Distillate	0.216
Dual Fuel	0.186

Table 5.2- *Ongoing fuel cost*

In relation to owners contingency the BNE process seeks the fixed cost of a hypothetical Best New Entrant peaking plant. The Belfast West site has been cleared of the previous power station and is currently land banked by the RAs for future power station development. While the RAs recognise that the site costs is informed by a specific site (compared to a purely hypothetical site), a detailed site assessment would be outside the scope of the exercise as it would require multiple sites to be investigated to this detailed level. For the purpose of this exercise the RAs consider it more appropriate to use a more generic assumption for contingency based on CEPA and PB's experience.

In response to the assumptions for the change in other non-EPC costs and Investment costs which are based on CEPA and PB's experience. The RAs have scrutinised this and are content that a rigorous assessment of these costs have been carried out by CEPA/PB.

In the absence of any other comments on the other Investment areas, the RAs have assumed that respondents are generally content with the proposed costs and have decided that these costs shall be kept the same as detailed in the consultation paper.

As a result of the points above, the SEM Committee have decided that the investment costs relating to the Alstom GT13E2 are as detailed in the table below. The following table summarises all the investment cost for each jurisdiction and for each fuel type.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
EPC Costs	92,629,000	92,199,000	91,433,000	91,009,000
Site Procurement Electrical connection Costs	763,556 6,600,000	763,556 6,600,000	1,507,768 7,492,999	1,507,768 7,492,999
Gas connection	3,400,000	0	1,690,000	0
Water connection	420,000	420,000	0	0
Owners Contingency	4,816,708	4,794,348	4,754,516	4,732,468
Financing Costs	1,852,580	1,843,980	1,828,660	1,820,180
Interest During Construction	2,220,691	2,150,970	1,913,241	1,880,171
Construction Insurance	833,661	829,791	822,897	819,081
Initial Fuel working capital	2,913,711	3,395,256	2,913,711	3,395,256
Other non EPC Costs	8,336,610	8,297,910	8,228,970	8,190,810
Accession & Participation Fees	3,915	3,915	3,915	3,915
Total	**124,790,432**	**121,298,726**	**122,589,676**	**120,851,648**

Table 5.3 – *Summary of Investment Costs for Alstom* GT13E2

As was the case in the consultation paper, it should be noted that the investment costs for the Distillate plant are less than the costs for the Dual Fuel Plant. The table below compares the costs detailed in the consultation with what has been decided by the SEM Committee.

Cost Item	Consultation Paper	Decision Paper	Variance
EPC Costs	91,009,000	91,009,000	0
Site Procurement	1,443,247	1,507,768	64,521
Electrical connection Costs	7,492,999	7,492,999	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,732,468	4,732,468	0
Financing Costs	1,820,180	1,820,180	0
Interest During Construction	1,880,234	1,880,171	-63
Construction Insurance	819,081	819,081	0
Initial Fuel working capital	3,614,384	3,395,256	-219,128
Other non EPC Costs	8,190,810	8,190,810	0
Accession & Participation Fees	3,915	3,915	0
Total	**121,006,318**	**120,851,648**	**-154,670**

Table 5.4 – *Comparison of Investment Costs for Alstom GT13E2 in Consultation and Decision Papers.*

6 RECURRING COSTS ESTIMATE

6.1 RECURRING COSTS FROM CONSULTATION PAPER

In the consultation paper, the RAs discussed the key cost areas that make up 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

6.2 RESPONSES TO RECURRING COSTS

Four respondents provided comments in relation to the recurring costs detailed in the consultation paper. Some respondents were pleased to see more stability in the estimates of the recurring costs as they though that the year on year changes fell in line with the typical expectation that may be expected year on year.

6.2.1 MANPOWER COSTS - LONG-TERM SERVICE AGREEMENT (LTSA) COSTS

One respondent questioned the assumptions made regarding the manpower requirement of the plant, highlighting that no allowance had been made for engineering level staff needed to manage the Long Term Service Agreement.

6.2.2 GAS TRANSMISSION COSTS

NIE Power Procurement Business noted that gas transportation tariffs used for Northern Ireland for 2010/11 are not the final rates, but rather the estimates published in August 2009.

They further questioned if the capacity calculation based on 4 hours of operation was prudent as gas nomination must be given as flat 1/24th profiles. It observed that under these assumptions gas could not be delivered to the plant without being subject to penalty charges or being restricted.

6.2.3 BUSINESS RATES

Premier Power noted that the business rates for the NI Distillate plat should be around €750k per annum. It also queried if there was an error with the NI dual fuel plant cost estimate of €926.7k.

6.3 DECISION ON RECURRING COSTS

In relation to the O&M costs, the RAs can confirm that the Long-term service agreement (LTSA) costs were included in the fixed annual maintenance component of the O&M costs. The maintenance regime for the selected plant when accumulating less than 3000 EOH per year requires between 2 and 3 days of scheduled downtime per year until the first Hot Gas Path Inspection, which would not be scheduled in the first ten years. The RAs and CEPA/PB's assumption is that the assumed vertically integrated investor will use engineering supervision from other generating assets to oversee the LTSA management.

Regarding the comment about potential changes to TUoS charges, similarly to previous years the RAs have based the assumptions on the latest updated available information.

The RAs note the different views that have been expressed regarding the appropriate basis for calculating gas transmission charges. The gas transportation tariffs are based on the latest available information, which is the forecast transportation tariff for 2011/12. The RAs also note the comment regarding the capacity allocation based on 4 hours of operation. This 4 hour assumption remains appropriate given the very infrequent running of the plant identified by the Plexos modelling.

The Business Rates calculations were based on figures obtained from formulae available from the Land and Property Services website[5]. The RAs welcome evidence from PPL regarding a query on the Business rates on the NI BNE site. As this peaker relates to the rate for "burning of natural gas where a steam turbine is not used for the purposes of the generating process", the Business rate for the Distillate from the consultation paper remains unchanged but updated with the change in exchange rate. The error with the Business Rate in the NI Dual Fuel plant has been amended.

In summary, the RAs have decided that there will be minimal changes to the recurring costs. The costs are summarised in the table below.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	996,614	978,596	815,423	800,682
Gas Transmission Charges	1,607,162	0	915,567	0
Operation and maintenance costs	1,816,000	1,791,000	1,816,000	1,791,000
Insurance	1,482,064	1,475,184	1,462,928	1,456,144
Business Rates	1,515,929	1,488,523	645,409	633,741
Fuel working capital	175,872	204,938	185,778	216,482
Total	**7,593,640**	**5,938,241**	**5,841,105**	**4,898,049**

Table 6.1 – *Summary of Recurring Costs for BNE Peaker for 2011*

Again it should be noted that as was the case in the consultation paper, the recurring costs for the Distillate plant are less than the costs for the Gas Plant. The following table compares the costs detailed in the consultation with what has been decided by the SEM Committee.

[5] http://www.lpsni.gov.uk/index/property_rating/rate_poundages_2010.htm

Recurring Cost	Consultation Paper	Decision Paper	Variance
Transmission & Market operator charges	767,133	800,682	33,549
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,791,000	1,791,000	0
Insurance	1,456,144	1,456,144	0
Business Rates	606,622	633,741	27,119
Fuel working capital	230,453	216,482	-13,971
Total	**4,851,352**	**4,898,049**	**46,697**

Table 6.2 – *Comparison of Recurring Costs for Alstom GT13E2 in Consultation and Decision Papers.*

7 OTHER POINTS RAISED IN CONSULTATION PAPER

7.1 COMMENTS RECEIVED BASED ON CONSULTATION PAPER

In addition, a number of respondents provided comments about volatility in the BNE methodology; these are being addressed as part of the medium term review of the capacity payment mechanism.

Other specific points of note are discussed below.

7.1.1 UNRECOVERABLE COSTS

Endesa Ireland noted that a downside of choosing a distillate fired power station meant that the costs associated with the gas connection was unrecoverable in the SEM. Endesa Ireland also considered that the fixed cost of a BNE should incorporate the costs associated with the strategic fuel stocks required in RoI.

7.2 DECISION ON OTHER POINTS RAISED

The concern raised regarding the issue of unrecoverable costs is outside the scope of this paper, but in response to the unrecoverable costs, the RAs have included the allowance for 3 days for strategic fuel stock as part of the assumptions for both RoI and NI. In addition to this the assumption for the distillate fired BNE plant also includes 0.5 days of commercial fuels stocks.

8 ECONOMIC & FINANCIAL PARAMETERS

8.1 ECONOMIC & FINANCIAL PARAMETERS FROM CONSULTATION PAPER

In the consultation paper and the CEPA report (Appendix 3 of ('Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2011' (SEM-10-034))[6]), extensive details were provided on the build up of the WACC parameters as well as the nature of the BNE investment.

The key conclusions for economic and financial parameters included in the RAs consultation were:

- A reasonable estimate for the gearing of the BNE is 60% as employed by the RAs for 2009.
- The economic plant life for the BNE will be 20 years.
- The appropriate range for the BNE cost of debt is 3.00% - 4.00% in the RoI and 3.00% - 4.00% in the UK.
- The appropriate range for the cost of equity for the BNE peaking plant is 6.90% - 7.81% in the RoI and 6.90% - 8.50% in the UK.

8.2 RESPONSES TO ECONOMIC & FINANCIAL PARAMETERS

There were a number of areas where the majority of responses related to within the economic and financial parameters heading. These were

- Type of investor
- Economic Life of the Plant and Financing Structure
- WACC Parameters

These are discussed under the subheadings below.

8.2.1 TYPE OF INVESTOR

ESBPG commented that the assumption that the investor is a subsidiary of an international utility precluded the possibility of Independent Power Producer entry into SEM which it believed should be encouraged. ESBPG also noted that there was several IPPs active in the Gate 3 process. Endesa Ireland also commented on the type of investor suggesting that a rational investor was not necessarily an international utility and that this assumption discriminated against smaller market participants.

8.2.2 PLANT LIFE & FINANCING STRUCTURE

Several parties discussed the plant life assumption of 20 years. ESBPG commented that the increase in plant life during last year's assessment from 15 to 20 years was incompatible with project financing structures, even if the technical life of the plant is longer. Endesa Ireland considered that it would be

[6] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=ab764619-7dee-4b19-afb2-d38b728bcfd4

more appropriate for the plant life to be reduced to 15 years and that insufficient justification had been provided in last year's estimation. Viridian also indicated that this was a fundamental change to the regime and should be addressed through the medium term review.

Bord na Móna commented that the increase from 15 to 20 years had not been reflected in the WACC assessment as they considered it would be practically impossible to secure funding for longer than 15 years for such projects and this needed to be factored into the return on equity.

8.2.3 WACC PARAMETERS

In general respondents considered the proposed WACC to be too low. The main areas of concern were in relation to cost of debt and cost of equity. These are discussed further below.

8.2.3.1 GEARING

There was no direct commentary on the appropriate level of gearing.

8.2.3.2 COST OF DEBT

Several parties noted that the proposed cost of debt is too low and does not reflect 'realities faced by participants'. One respondent noted that the 'proforma cost of debt for Ireland is 4.78%'

One respondent noted that the proposed WACC range is appropriate, but that the cost of debt should be set at the higher end of the proposed range.

8.2.3.3 COST OF EQUITY

Several respondents commented on the appropriateness of using the CAPM to derive the WACC, and that there may be an over-reliance on spot rates which might drive volatility.

Several respondents also stated that the cost of equity is too low, especially for RoI.

One respondent stated that the risk profile of the participants in the competitive market is higher than that of utilities subject to 'multi-annual revenue review' processes.

8.3 DECISION ON ECONOMIC & FINANCIAL PARAMETERS

The RAs discuss the key points raised on the economic and financial parameters below.

Several respondents noted that the proposed ranges for the cost of debt and cost of equity are too low. Several also noted that the economic life of the plant and assumed financial structure is too long. Whilst this feedback is appreciated, no compelling evidence has been presented to the RAs or CEPA, and as such no changes are proposed to CEPA's ranges. Specific responses are provided below.

8.3.1 TYPE OF INVESTOR

For the 2011 BNE Peaker, the RAs have decided to assume that the investor is an integrated utility raising finance at the corporate level. The RAs have no intention of discouraging investment into the SEM and have taken account of the potential range of investors in setting the economic and financial parameters; they consider that a truly Independent Power Producers (IPPs) may struggle to raise the necessary finance to reach completion. IPPs without parent/ corporate support will continue to face challenges in raising debt finance, whereas investment grade utilities are more likely to be able to close transactions.

8.3.2 PLANT LIFE & FINANCING STRUCTURE

The RAs recognise that the change in economic plant life assumption in 2010 was a significant determinant of the 2010 final BNE annual price. CEPA/PB had recommended that it is relevant to look at investor decisions made in markets other than the SEM, as investors have a range of market opportunities to invest in, and their experience is that even in risky markets investors are willing to invest on the basis of a twenty year or more economic life. The RAs at this time are satisfied with the recommendations provided by CEPA/PB based on their experience and expertise with these projects and discussion with financial institutions. They have seen no new evidence to reconsider the economic plant life adopted for the 2010 allowance.

The financing structure is consistent with this economic life: 40% of project cost funded by corporate equity, which by its nature takes a long term view and 60% by debt with an average life of 10 years.

8.3.3 WACC PARAMETERS

Regarding the cost of debt, the reduction in the proposed range for the cost of debt is driven in large part by falling spreads for investment grade debt. This data is drawn from actual market data for investment grade corporates, and cross-checked against individual utility company debt issues. CEPA's proposed range for RoI is 3.0% – 5.0%, so the respondent's specific 'proforma' cost of debt sits within this range. The RAs in the past have found it appropriate to take the midpoint of the ranges proposed by their consultants, they will continue to employ this methodology.

The RAs and CEPA's view remains that the most appropriate theoretical approach is to use the CAPM and to cross check the outputs from CAPM against actual market data. Similarly, they have not relied solely on spot rates, which would be overly volatile, but cross-check spot rates, e.g. for the risk-free rate, against recent trends in order to give their best estimate of the appropriate ranges for the WACC for 2011. The RAs believe that the building-block approach of the CAPM this is the most robust methodology for the purposes of estimating the cost of capital for a notional BNE peaking plant.

One respondent stated that the risk profile of the participants in the competitive market is higher than that of utilities subject to 'multi-annual revenue review' processes, whilst the RAs agree that the risk profile of participants is typically higher than that of utilities subject to multi-annual reviews, they have taken account of this through setting an equity beta of 1.2 - 1.3 which is greater than one would expect to see for regulated energy companies subject to multiyear reviews.

The data for the ERP is taken from long term historical trends. It was noted in the Conference call facilitated by IBEC and attended by the RAs, CEPA and several respondents in July that the estimation of the ERP has its difficulties, it is a variable whose value cannot be directly observed and hence is one of the more contentious parameters estimated when determining a company's WACC.

Overall the RAs find there is no compelling evidence received to merit a change the specific parameter assumptions used in the building block cost of capital estimate. Based on this the SEMC have decided that the WACC values detailed in the consultation paper will be used for the 2011 BNE calculations. These are summarised below.

Element	2011 RoI	2011 UK
Risk-free rate	2.00%	1.75%
Debt premium	2.00%	1.75%
Cost of debt	**4.00%**	**3.50%**
ERP	4.75%	4.75%
Equity beta	1.25	1.25
Post-tax cost of equity	**7.95%**	**7.70%**
Taxation	12.50%	28.00%
Pre-tax cost of equity	9.09%	10.70%
Gearing	60%	60%
Pre-tax WACC	**6.04%**	**6.38%**

Table 8.1 – *Proposed WACC values to be used for the BNE Peaker for 2011*

9 BEST NEW ENTRANT PEAKER FOR 2011

9.1 SUMMARY OF COSTS

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	Republic of Ireland Dual Fuelled	Republic of Ireland Distillate	Northern Ireland Dual Fuelled	Northern Ireland Distillate
Investment Cost (excl Fuel Working Capital	121,877	117,903	119,676	117,456
Initial Working Capital (including Fuel)	5,299	5,502	5,009	5,329
Residual Value for Land & Fuel	-1,139	-1,288	-1,284	-1,424
Total Capital Costs	**126,037**	**122,118**	**123,401**	**121,361**
WACC	6.04%	6.04%	6.38%	6.38%
Plant Life (years)	20	20	20	20
Annualised Capex	11,021	10,678	11,089	10,906
Recurring Cost	7,594	5,938	5,841	4,898
Total Annual Cost	**18,614**	**16,616**	**16,930**	**15,804**
Capacity (MW)	193.6	190.1	193.6	190.1
Annualised Cost per kW	**96.15**	**87.41**	**87.45**	**83.14**

Table 9.1 – *Annualised costs for BNE Peaker for 2011*

9.2 DECISION ON BEST NEW ENTRANT PEAKER FOR 2011

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

The Best New Entrant Peaker for 2011 is the Alstom GT13E2, located in Northern Ireland and uses Distillate fuel

10 INFRA MARGINAL RENT

10.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER

As discussed in the consultation paper (SEM-09-072), in order to calculate the Infra Marginal Rent, the most up-to-date SEM Plexos model was used. This model is identical to that used in the recent Directed Contracts parameter calculations. This model has been published by the RAs. Twenty five full year half hourly simulations of the SEM in 2011 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 Alstom GT13E2 plant was not scheduled at all in any of the twenty five iterations. On the basis of this analysis, it was assumed that there will be zero Infra Marginal Rent.

10.2 RESPONSES TO INFRA MARGINAL RENT

No responses were received in relation to the proposed revenue from Infra Marginal Rent.

10.3 DECISION ON INFRA MARGINAL RENT

As detailed in the paper on the scope the medium term review of the CPM (SEM-09-035), the RAs intend to look at the Infra Marginal Rent Calculations.

The RAs can confirm that the same assumptions for planned outage duration (13 days) and forced outage rate (2%) as had been used in previous years were included within the modelling for the calculation of infra marginal rent for a BNE plant in 2011.

Therefore for the purposes of the 2011 BNE Calculation, the SEMC have decided that there will be zero Infra Marginal Rent, as calculated for the consultation paper.

11 ANCILLARY SERVICES

11.1 ANCILLARY SERVICES FROM CONSULTATION PAPER

The AS rates for tariff year 2010/11 have not be developed, they are subject of a consultation[7] during the summer of 2010. For the calculation of the Ancillary Services (AS) for the BNE peaker for 2011, the RAs have used the criteria as documented in the consultation paper 'Harmonised Ancillary Services & Other System Charges Rates Consultation' published on 8th June 2009 (SEM-09-062)[8].

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 190.1MW
- Run hours is 2%
- Load factor is 60%

11.2 RESPONSES TO ANCILLARY SERVICES

Two types of comments where received regarding in respect of ancillary services income:

- The basis on which the ancillary services estimate was calculated; and
- Whether the plant would be able to secure an ancillary service contract for the full capacity.

Several respondents commented that the 5% running assumed for the purpose of ancillary services was too high and that it should instead be based on the output of the PLEXOS modelling iterations.

One respondent further queried the apparent difference in assumptions behind the calculation of ancillary services calculation between the CEPA paper and the consultation.

In addition to this Bord na Móna indicated that Eirgrid had stated that it was under no obligation to contract for Ancillary Services with any generator above the minimum requirements set out in the grid code. Bord na Móna suggested that it might be more appropriate to include mid-range estimates for the BNE peaker plant to reflect this. Bord na Móna further welcomed the adjustment to the ancillary services figure made as part of last year's calculation.

11.3 DECISION ON ANCILLARY SERVICES

The estimates of ancillary services revenues contained in the consultation document were based on information provided by the TSOs (Transmission System Operators). In the consultation paper the methodology of calculating the AS was consistent with last year approach and allowed for the plant to operate for 5% of the hours for limited

[7] http://www.soni.ltd.uk/upload/Harmonised%20Ancillary%20Services%202010-11%20Consultation.pdf

[8] http://www.allislandproject.org/en/transmission.aspx?article=422a7c94-d5bf-4bf3-8651-0f363f795366

running, check and maintenance. We note the view from respondents that 5% is a significant number of hours and the RAs and CEPA/PB have revisited this assumption in light of the responses. Calculations for ancillary services were re-evaluated and a figure of run hours of 2% was thought to be more appropriate.

The RAs also clarified the applied penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events. The RAs have assumed that this is appropriate for a best new entrant peaker. This assumption results in a penalty payment of €30,544, based on the proposed harmonised tariffs for AS, thus leading to a reduction in the value of AS revenue deducted from the ACPS. The RAs have decided therefore to maintain the figures below which are based on the Ancillary Services Harmonisation calculations.

The SEMC have therefore decided that value of Ancillary Services that the BNE peaker for 2011 would achieve is €387,705. This equates to €4.407 per kW for a 190.1MW 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	23,834	2.13	25,383
Tertiary Operating Reserve 1	26,644	1.76	23,447
Tertiary Operating Reserve 2	26,644	0.88	11,724
Replacement Reserve Unit Synchronised	26,644	0.2	2,664
Replacement Reserve Unit De-Synchronised	3,097,413	0.51	789,840
Reactive Power (Leading)	21,024	0.13	2,733
Reactive Power (Lagging)	21,024	0.13	2,733
Total Revenue			**868.249**
Penalties			30,544
Total (after penalties allocation)			**837,705**

Table 11.1 – *Summary of Ancillary Services Costs for 2011 – assuming 2% running hours*

12 DECISION ON BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2011

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2011. This includes the deduction of any revenues obtained from Infra Marginal Rent or Ancillary Services.

Cost Item	Northern Ireland Distillate
Annualised Cost per kW	83.14
Ancillary Services	4.41
Infra-marginal Rent	0.00
BNE Cost per kW	**78.73**

Table 12.1 – *Final costs for BNE Peaker for 2011*

13 CAPACITY REQUIREMENT FOR 2011

13.1 CAPACITY REQUIREMENT FOR 2011 FROM CONSULTATION PAPER

As detailed in the consultation paper, the methodology used for calculating the Capacity Requirement for 2011 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. In addition, the RAs detailed the process used in calculating the Capacity Requirement, in conjunction with the TSOs. This paper also contains the data sheets used in the Adcal calculation as a series of appendices.

13.2 RESPONSES TO THE CAPACITY REQUIREMENT FOR 2011

Six respondents provided comments in relation to the Capacity Requirement Calculations. While some of these considered the Capacity requirement for 2011 as being reasonable, others welcomed the RA's intention to revisit the demand forecasts to ensure they reflect the actual demand trend. A number of respondents welcomed the development of publishing an information note on the data used in the calculation of the deemed capacity requirement during the consultation period on the BNE peaker paper, as it gives further information to market participants when forming their responses to the consultation process.

Bord na Móna raised concerns over the reserve margin when comparing the capacity requirement. They noted two key issues with the deemed capacity requirement reserve margin which they described as being at such a low level:

1. Firstly, if the market was in equilibrium, the Capacity Payments Mechanism could not support any more plant on the system than the deemed capacity requirement. If we remove the capacity credit for wind when the wind output is close to zero, this leaves the market potentially in deficit at peak load times. The coincidence of low wind with peak demand has happened previously on a number of occasions around the winter peak demand periods.

2. Secondly, the deemed capacity requirement does not factor in the obligation of generators to provide reserves to the system. The provision of capacity to provide these reserves cannot be remunerated from Ancillary Services, (and indeed, the margins earned from such revenues are explicitly removed in the process to estimate the BNE peaker), yet generators are penalised for not providing the minimum level of reserves through the generator performance incentives scheme.

A number of respondents commented on the demand forecasts. Viridian noted that demand forecasts are seemingly made with sole reference to the state of the economy. They strongly suggested that it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver. They used the example of this in January 2010 when all peak demand records (with the exception of the summer night valley) were set in the midst of Ireland's deep recession. IBEC also stated that Peak Demand this year has reached a record high despite an underlying recession – led reduction. The calculation of peak demand in the consultation paper appears to solely reference the state of the economy and excludes other significant factors such as weather.

PPB disagreed with the use of "target" forced outage rates and believed that actual rates (averaged over a number of years) should be used which more accurately reflects the risk to security of supply. Viridian also emphasised that all plant availability should be based on historical data and not projected from expected improvements. If improvements in performance do materialise then they will automatically be factored in future historical data

A number of respondents noted that the treatment of wind and the wind capacity credit calculation was not clear in the consultation paper and that the method used could result in the Capacity Requirement being understated.

13.3 UPDATE ON DEMAND FORECASTS & IMPACT ON CAPACITY REQUIREMENT FOR 2011

As highlighted in the consultation paper, the RAs decided to revisit the demand forecasts with the TSOs to determine if there is any need to change the forecasts based on the most up to date information. The update on the demand forecasts is below.

As a result of the discussions with EirGrid, the forecasts used in the consultation paper are the most accurate forecasts, based on the actual data available. It is therefore proposed that no change is made to the forecasts for the Republic of Ireland.

In the case of Northern Ireland discussions with SONI resulted in change in the forecast to use the most up to date information. SONI has recently reviewed and updated its Energy and Peak demand forecast. Therefore an adjustment has been made to the Northern Ireland Energy and Peak demand forecasts to reflect this. This forecast has been discussed with the RAs who have agreed with rationale and methodology used in compiling the updated forecasts. A document outlining the background to the SONI forecasts has now been made available on the SONI website[9].

In addition to the above, EirGrid and SONI both provided an updated view of the connection dates that will be available on the system in 2011.

As a result of these changes, the half hourly data was updated and fed into the Adcal (CREEP) model. The Capacity requirement was then recalculated.

13.4 DECISION ON CAPACITY REQUIREMENT FOR 2011

Some respondents noted that it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver. In conjunction with the TSOs the demand forecast calculation takes into account economic conditions, historical yearly load shape and typical weather patterns.

The high demand in January 2010 was due to extreme weather conditions. In generation adequacy assessments, a low, medium and high demand forecasts is used, though the high forecast is still based on economic forecasts rather than extreme weather. It is common in Europe to report generation adequacy against typical demand and a more extreme demand event e.g. one in 3 or 5 year demand. Practice does vary from country to country. The cold weather in January 2010 was more like a 1 on 40 year weather event. In terms of the peak demand forecast, SONI adjust this to a temperature standard known as Average Cold Spell (ACS) that adjusts the actual figure to a figure

9 http://www.soni.ltd.uk/upload/2010%20Forecast%20Of%20NI%20Peak%20Demand%20And%20Energy%20Production%20-%20June%202010.pdf

that can be compared year on year if the temperature each year were averagely the same. It is this ACS corrected figure that is used, therefore the forecasted peak demand does account for the weather and temperature.

In response to the concerns raised over the reserve margin, operating reserve forms part of a generator's capacity that is remunerated by the CPM. It is System Operator practice to commit operating reserve to meet demand if required during capacity shortages. These events are rare. Generators dispatched to, and operating at, maximum capacity continue to be remunerated for provision of ancillary services. When operating at maximum capacity, they are not penalised for not providing reserve.

The methodology of calculating wind capacity credit takes this into account by using typical, real wind generation data from previous years. This method is similar to that used in the Generation Adequacy Report. The System Operators are of the view that it correctly calculates the capacity worth of wind generation.

The RAs acknowledge the comments received in relation plant availability. The plant availability used is based on an historical average availability achieved in Northern Ireland over a 5 year period and seen as best practice target. Generators should not be rewarded for poor availability.

Based on the changes to the Northern Ireland Demand forecast and the increase in connection dates information in the Republic of Ireland, the RAs worked with the TSOs in rerunning the Adcal model. The second run of the Adcal model result in the Capacity Requirement increasing by 20MW to 6,922MW.

A number of participants welcomed the publication of the data used in the calculation of the deemed capacity requirement which was published with an information note. The inputs used for the 2011 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 2011	A combined load forecast for 2011, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The base year used to develop this forecast was 2008. The period used for analysis was 1 January 2011 to 1 January 2012 as the CREEP (Adcal) model uses a 364 day sample. Two traces were agreed: 1) Total Load Forecast for 2011 2) Total (In Market) Conventional Load Forecast See Appendix 1 – Load Forecast for 2011
Generation Capacity	A list of all generation to be in place in 2011 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2011, 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. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9489MW** See Appendix 2 – Generation Capacity for 2011

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 2011 used was **2,323**MW. This results in a Capacity Credit of **0.151**. The Time Weighted Market Wind Capacity in 2011 was **1,792**MW. Therefore the Wind Capacity Credit is derived as 270**MW** (1,792 x 0.151) See Appendix 3 – Wind Capacity in 2011 See Appendix 4 – 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 5 – Average SOD for 2011
Force Outage Probability (FOP)	As highlighted in the consultation paper, the RAs maintained the value of **4.23%** for the FOP. It should be noted that an FOP of 0.167% was used for the Moyle Interconnector, based on historical data.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 13.2 – *Summary of Inputs into Adcal Model*

As a result of the further analysis carried out in conjunction with the TSOs, the SEM Committee have determined that the Capacity Requirement for 2011 is **6,922MW.**

The Capacity Requirement for 2011 is 6,922MW

14 ANNUAL CAPACITY PAYMENT SUM FOR 2011

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2011 as detailed in Sections 12 and 13 above, the Annual Capacity Payments Sum (ACPS) for 2011 is determined to be €544.9. The proposed figures are detailed in table 14.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2011	78.73	6,922	544,956,545.05

Table 14.1 – ACPS for the Trading Year 2011

The Annual Capacity Payments Sum (ACPS) for 2011 is €544.9M