Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant,

Capacity Requirement

&

Annual Capacity Payment Sum for the Trading Year 2016

Consultation Paper

May 2015

SEM-15-032

1 EXECUTIVE SUMMARY

This paper sets out the SEM Committee's proposed setting for the Annual Capacity Payment Sum (ACPS) for Trading Year 2016 in the Single Electricity Market (SEM). The ACPS has been calculated by multiplying two key inputs:

- The estimated fixed costs of a Best New Entrant (BNE) Peaking Plant, minus revenues from infra-marginal rent and ancillary services

- The installed capacity required to satisfy a Loss of Load expectation of 8 hours per year on an all-island basis

While the annualised cost of a BNE Peaking Plant was calculated for 2014 and 2015 by indexing the number computed in 2013, the value for 2016 has been re-opened for ground-up calculation in line with the method used in 2007 - 2013. The SEM Committee have implemented an approach for the calculation that is consistent with the calculation for the 2013 ACPS.

The annualised cost used in the ACPS calculation forms the first part of this paper. We introduce the technology options covering the main characteristics of a new entrant peaking plant in the SEM and discuss the economic and financial parameters associated with a rational investor coming to market.

The technology chosen, following extensive research by the contracted firm Cambridge Economic Policy Associates (CEPA) in association with Ramboll is recommended to be an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland. This is the same technology and location chosen in 2013.

Through the work undertaken by CEPA in association with Ramboll, the estimated annualised fixed cost, net of estimated Ancillary Services revenue and Infra-Marginal Rent is **€65.50** kW/year.

The remaining part of the paper concentrates on the annual calculation for the Capacity Requirement. The AdCal modelling undertaken by the Transmission System Operators - System Operator Northern Ireland (SONI) and EirGrid - seeks to forecast the generation capacity needed for the year 2016 based on a defined Generation Security Standard. The Capacity Requirement for 2016 was calculated to be **7070 MW**.

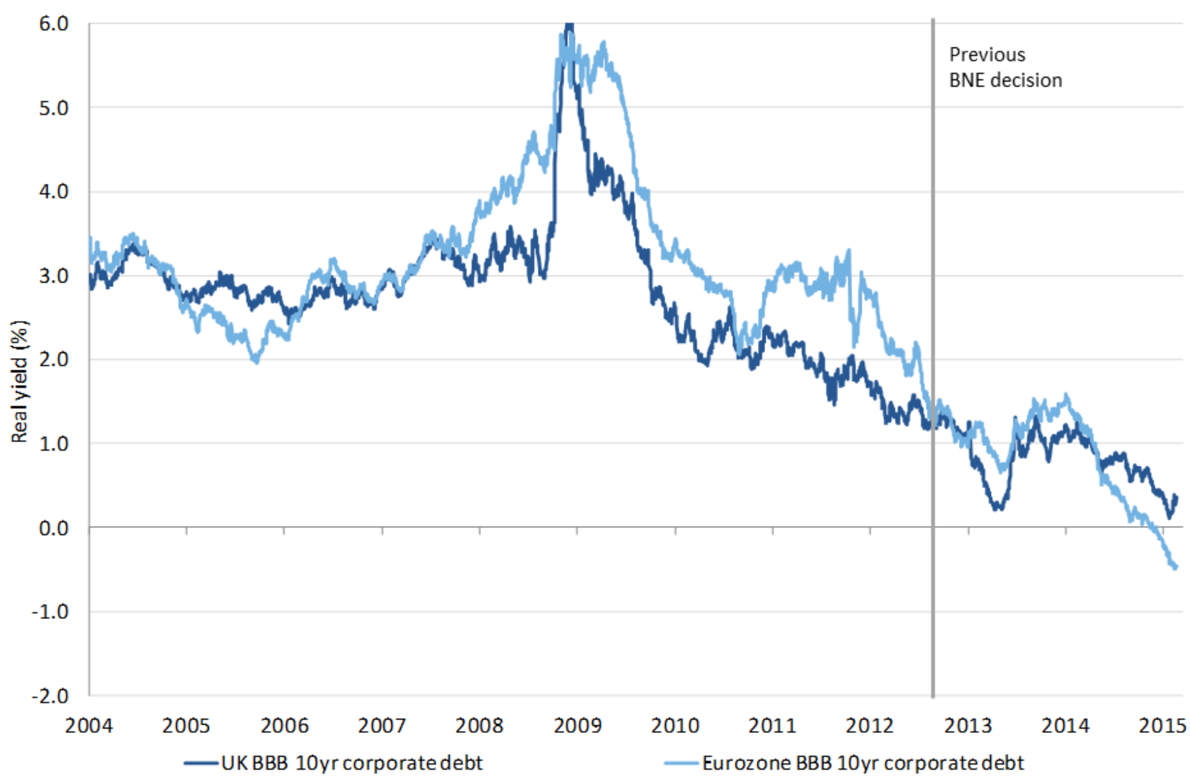
Computing the product of these constituent price and quantity values yields an Annual Capacity Payment Sum (ACPS) which, for the 2016 calendar year is found to be **€463,103,448**. A summary of the price quantity elements are shown in the following table:

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2016	65.50	7070	463,103,448[1]

This figure compares to the higher ACPS figure of €574,178,540 in 2015.

A driving factor for the reduction is a significant drop in the estimated cost of capital in the BNE component. In particular, the cost of debt is estimated to be substantially lower than it was at the time the previous figure was calculated (2012). The figure below is taken from CEPA's report and demonstrates the trend:

Figure 5.1: Corporate cost of debt in UK and Eurozone



Source: CEPA analysis based on Bloomberg data

[1] The BNE Peaker Cost is rounded to the nearest Euro cent in the table, but the multiplication to arrive at the ACPS has been made without rounding.

The cost of debt is a significant contributor to the calculation as it contributes to the annual rate used within the Capital Asset Pricing Model over the life (20 years) of the investment simulation. A lower cost of debt implies a lower required return on investment, all else equal.

While the derivation of the ACPS for 2016 has been built using the methodology that stood during 2007 through 2013, it should be noted that the SEM Committee do not intend to repeat the entire process for 2017. For the 2017 calculation the SEM Committee are minded to use the method employed for the 2014 and 2015 figures. One important exception is the forecast revenues for the plant from Ancillary Services. It is anticipated that potential revenues for AS under the DS3 framework will be better understood at that time, and the SEM Committee wish to flag their preference that these revenues be input to the calculation instead of rolling over previous estimates.

For further information on indexing see section 3.3 *CPM Medium Term Review – Final Decision Paper*[2].

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

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3 INTRODUCTION

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

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

The methodology for the determination of the fixed costs of a BNE peaking plant was set out by the Northern Ireland Authority for Utility Regulation ("**the Utility Regulator**") and the Commission for Energy Regulation ("**CER**") (together the Regulatory Authorities ("**SEM Committee**")), in two decision papers published on the All-Island Project website in 2007[3]. Subsequently, the SEM Committee reviewed these costs in relation to the determination of the value of ACPS for the calendar year 2008[4]. The same process was used for the calculation of the fixed costs of a BNE peaking plant for all subsequent years up to calendar year 2013 from which time the calculation has been indexed using the Harmonised Consumer Price Index (HCPI). For 2017 the Regulatory Authorities are minded to approach the calculation of these figures in the same way; with appropriate deductions for Infra-Marginal rent and for system services under the new DS3 framework.

The Annual Capacity Payment Sums for all previous years are summarised in Appendix 1 of this paper.

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

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

This Consultation Paper sets out:

1. The options for the BNE peaking plant for 2016 and proposes a technology option. The paper then explores the fixed costs associated with the proposed technology option as well as the financial parameters and sets out the proposed resultant value in €/kW/year.
2. The proposed Capacity Requirement for 2016 and the approach used for its determination.

The SEM Committee (in line with previous Best New Entrant Peaking Plant calculations) have engaged Cambridge Economic Policy Associates ("**CEPA**") in association with Ramboll ("**Ram**") to assist in the calculation of the fixed costs of a BNE peaking plant for 2016.

This paper covers the key recommendations made by **CEPA/Ram**, and provides the SEM Committee' proposed position on the various components. The remainder of the 2016 ACPS project is projected to follow the below timetable:

Close of submissions to this paper	12th June 2015
Consideration of responses	June / July 2015
Final recommendations to SEM Committee	July Meeting
Publication of the 2016 ACPS and associated parameters	August 2015

4 BACKGROUND

In May 2005 the SEM Committee set out the options for the SEM CPM[5]. In the paper the SEM Committee indicated their proposal to develop a fixed revenue CPM that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code.

In March 2006[6] a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of

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

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

alternative options for the CPM. The processes that the SEM Committee proposed for determining the annual capacity payment and the general process by which the input parameters to the CPM would be set were also covered.

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

The Regulatory Authorities also determined that the resulting cost should be adjusted to account for the infra-marginal rent the BNE peaking plant may derive through its sale of energy into the pool, as well as the estimated revenues the plant may derive through its operation in the Ancillary Services markets.

In 2012 the SEM Committee concluded a Review of the CPM entitled "Single Electricity Market CPM Medium Term Review"[7]. A key outcome of the review was that the calculation of the BNE fixed costs would proceed as normal for the Trading Year 2013, and then be indexed to that calculated value using the HCIP for the Trading Years 2014 and 2015. The SEM Committee also decided to change other aspects of the calculation, including that of the infra-marginal rent deduction, as detailed later in the paper.

The setting of the ACPS for 2014 and 2015 was performed in accordance with these new provisions, with the BNE fixed costs derived via the indexing of the 2013 value.

The Capacity Requirements for 2014 and 2015 were not derived using indexing but were calculated using the standing ground-up modelling methodology used in previous years.

The SEM Committee decided in late 2014 that the calculation of the ACPS for 2016 would be completed via full application of the detailed original BNE methodology during 2015, and that indexing of that value would then apply for the Trading Year 2017.

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

5 TECHNOLOGY OPTIONS

As stated earlier, the SEM Committee have employed CEPA in association with Ramboll to assist in the calculation of the fixed costs of a BNE peaking plant for 2016. CEPA/Ram independent report is referenced in Appendix 4 of this document and is referred to throughout this paper.

5.1 APPROACH USED FOR SELECTION OF TECHNOLOGY

In the interests of consistency, the SEM Committee asked CEPA/Ram to build on the approach used in previous years. The approach used by CEPA/Ram is documented in Section 2.2 of their report.

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

5.2 CRITERIA FOR SELECTION

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

The development of the long list for 2016 has been drawn from the conclusions previously reached through CPM consultation processes.

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

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

5.3 INITIAL FILTER AND SHORTLISTING

The table below shows the model characteristics of each gas turbine. Each turbine has differing characteristics, which, given the requirements will allow for the best determination of the plant. As there are no requirements for multiple units in the investment; it is expected that a large plant with a high economy of scale will be selected.

Further details on the initial filtering process are discussed in the CEPA/Ram report in section 3.3.

Gas turbine model	Characteristics
Alstom GT11N2	Medium industrial machine, with good fuel flexibility.
Alstom GT13E2	Medium/large industrial machine, relatively high efficiency, generally for operation on good quality gas and distillate oil.
Ansaldo AE64.3A	Originally developed under licence with Siemens. Medium industrial machine, typically burning natural gas and/or distillate oil in smaller CCGT plant, or for CHP.
Ansaldo AE94.2	Originally developed under licence with Siemens, Ansaldo's version of Siemens' SGT5-2000E. Competes with 13E2 in terms of capacity, but less efficient in simple cycle. Silo combustors give it excellent fuel flexibility.
GE 6B.03	"Workhorse" small industrial machine, low efficiency. Excellent fuel flexibility.
GE 6F.01	Originally marketed as the 6C, upgraded and renamed. "F" class machine for operation on natural gas providing good CCGT efficiency <100MW, and for industrial/cogeneration.
GE 9E.03	"Workhorse" medium industrial machine, low efficiency. Excellent fuel flexibility.
GE LM6000PC Sprint	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.
GE LM6000PG Sprint	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.
GE LMS100 PA	Largest and most efficient aero-derivative with typical aero-derivative characteristics.
P&W FT8 Swift Pac 60	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.

Gas turbine model	Characteristics
Siemens SGT5-2000E	Medium/large industrial machine. Competes with 13E2 in terms of capacity, but less efficient in simple cycle. Silo combustors give it excellent fuel flexibility.
Siemens SGT-800	Small/medium industrial machine, high efficiency for its capacity and type. Good for cogeneration and industrial applications.
Siemens Trent 60 WLE	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.

Table 5.3 – *Summary characteristic of each Gas Turbine.*

5.3.1 CANDIDATE PLANTS

The candidate GTs for the 2016 trading year calculation were:

- 1 x Siemens SGT5-2000E
- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2

CEPA/Ram then took the decision to proceed to conduct a more detailed assessment of the costs of each of the candidate plants.

5.4 OTHER TECHNOLOGY OPTIONS CONSIDERED

The initial starting point for the technology selection was to consider all options available for a generating plant. In previous BNE calculations the below plant types were deemed inappropriate:

- Second-hand plants
- Interconnectors
- Aggregated Generator Units (AGUs)

Pumped storage systems were considered, and also compressed air energy storage systems were discussed in previous considerations but were dropped in favour of a less costly option.

5.5 ENGINEERING, PROCUREMENT & CONSTRUCTION (EPC) ANALYSIS

Based on the characteristics options detailed in section 5.3, a more detailed cost analysis was carried out of the shortlist to consider the investment costs for each option. As mentioned above, each of the options was analysed taking into consideration the costs for the units running on gas and the costs for the units running on distillate.

To maintain continuity, and provide a good comparison with previous years, the approach CEPA/Ram took to cost estimation has remained the same.

The shortlisted plants were modelled using the latest updated version of GT PRO and its associated cost estimating program PEACE. In addition, reference plant was modelled to provide further calibration of the plant cost estimations.

The EPC Cost estimates provided by CEPA/Ram are detailed in Table 5.5 below.

Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)
Alstom GT13E2	Distillate	195.7	94.5
	Duel	203.9	95.6
AE94.2	Distillate	166.5	84.3
	Duel	167.7	82.7
SGT5-2000E	Distillate	178.6	91.1
	Duel	180.4	91.4

Table 5.5 – *Summary of Proposed EPC costs for Short Listed Plants (Source: CEPA/RAMBOLL)*

Further information on the EPC costs and assumptions used can be found in the CEPA/Ram report in section 3.4.2.

5.6 CHOSEN TECHNOLOGY OPTION

The decision taken for the proposed technology options based on the assessment of EPC costs per kW for candidate plants are outlined below.

Plant Type	Fuel Type	EPC Cost €/kW
Alstom GT13E2	Distillate	482.6
	Gas	469.1

AE94.2	Distillate	506.4
	Gas	493.4
1 x SGT5-2000E	Distillate	509.9
	Gas	506.9

Table. 5.6 – Specific EPC cost estimates for short-listed plants.

On the basis of the approach outlined above, in CEPA/Ram's opinion, it is likely that the **BNE GT for 2016 is an Alstom GT13E2**. This plant has a capacity of 202MW (198.0MW with 2 per cent average degradation) in dual fuel configuration.

Both the distillate and the dual fuel options are carried over for further analysis in the following sections for locations in both NI and RoI.

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

The Proposed Technology Option for the BNE Peaker 2016 is the Alstom GT13E2

5.6.1 TECHNICAL ASSUMPTIONS FOR SELECTED PLANT

The following has been built in to the performance and cost models for the 1 x ALS GT13E2 plant option:

- Ambient conditions at the grid's winter peak.
- Transmission voltage of 110kV for NI and 220kV for the RoI.
- Distillate storage for both distillate options of 3.5 days at maximum plant load and 3 days for dual fuel option to reflect secondary fuel obligation in Ireland.
- Water storage and treatment capability for 3.5 days of water injection at 1.18:1 water to fuel ratio (mass basis) at maximum plant load.
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.

- No black-start capability (it is assumed that had black-start capability been included, the additional costs would have been offset by the subtraction of the associated ancillary service revenue).
- Gas network pressure does not drop below 30 barG.
- Average lifetime draught losses of 6 and 12.5 mbar for inlet and outlet respectively.
- Average lifetime degradation for power output and heat rate of 2.5% and 1.25% respectively for distillate option and 2% and 1% for gas operation.

6 INVESTMENT COSTS

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

- EPC Costs;
- Site Procurement costs;
- Electrical Connection costs;
- Gas and Make-up Water Connection costs;
- Owner's Contingency;
- Financing, Interest During Construction (IDC) and Construction Insurance;
- Up-front costs for fuel working capital;
- Other non-EPC costs;
- Market Accession and Participation Fees.

Recurring operational costs have been subdivided as follows;

- Transmission and market operator charges
- Operation and maintenance
- Insurance
- Rates
- Working fuel capability

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

6.1 EPC COSTS

Table 6.1 summaries the proposed EPC costs for the Alstom GT13E2 for each fuel type. There is a difference in the EPC cost in the two locations due to the difference in costs associated with the differing transmission voltages. It should be noted that the costs below assume the period to build the plant is 18 months with a lead time for the transformer of 12 months being on the critical path for delivery and commissioning.

Plant Type	Location	Fuel Type	EPC Cost (€m)
1 x Alstom GT13E2	NI	Distillate	94.5
		Dual	95.6
	RoI	Distillate	95.7
		Dual	96.9

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

6.2 SITE PROCUREMENT COSTS

In common with the approach undertaken by the SEM Committee in previous years, this section considers the costs associated with locating a BNE plant in either relevant jurisdiction. As noted in previous BNE reports, there are a number of conventional generation plants expected to enter the market in the next ten years. Sourced from the All-Island Generation Capacity Statement (2015-2024)[8], the table below lists thermal generators that have signed agreements and confirmed dates to connect to the island over the next ten years.

Plant	Export capacity
Great Island CCGT	431
Cahernagh OCGT	101
Dublin Waste to Energy	62
Nore OCGT	98
Suir OCGT	98
Cuilleen OCGT	98

Table 6.2a: Confirmed contracted conventional generation capacity to the island up to 2024. Source: EirGrid/SONi

[8] In their report, CEPA reference the 2014-2023 Generation Capacity Statement; the 2015-2024 Statement was not available at the time of drafting.

As in previous years, for the RoI we consider that a BNE investor would be able to obtain agricultural land, probably close to a relatively unconstrained part of the transmission network.

In previous years, it had been assumed that the site of the former Belfast West power station was the most appropriate location in NI. However, it is possible that this particular site may become utilised in the short to medium-term. For these reasons, the site costs in NI are derived for this project using the same approach that is used in the RoI.

These costs are detailed in the table below. Further details are available in Section 4.3 of the CEPA/Ram report.

A summary of site procurement costs are shown below;

Location	Fuel type	Required area (m^2)	Estimated site cost (€)
NI	Distillate	20,700	€959,078
	Dual	20,500	€949,811
RoI	Distillate	20,700	€767,262
	Dual	20,500	€759,849

Table 6.2b – *Summary of Site Procurement Costs*

6.3 ELECTRICAL CONNECTION COSTS

For Northern Ireland, it was assumed that a 110kV connection would be used for the Belfast West site. In the Republic of Ireland, it was assumed that the connection would be at 220kV and require a 4km connection.

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

Location	Electrical Connection Cost (€)
Northern Ireland	€10,529,100
Republic of Ireland	€6,970,000

Table 6.3 – *Summary of Electrical Connection Costs*

6.4 GAS AND MAKE-UP WATER CONNECTION COSTS

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

Location	Cost of water connection (€)	Cost of gas connection (€)
Northern Ireland	€490,000	€3,620,000
Republic of Ireland	€490,000	€3,620,000

Table 6.4 – *Summary of Gas and Make up Water Connection Costs*

The estimated costs associated with securing a water supply and a connection to the gas network (where applicable) are considered. For the water connection, the total cost of an installed 1km pipeline, 4 inches in diameter, has been assumed for RoI. This cost was estimated using GT MASTER/PEACE.

6.5 OWNER'S CONTINGENCY

As with previous years' exercises, CEPA/Ram has recommended an owner's contingency value of 5% of the EPC costs. This is based on their past project experience. The estimated Owners Contingency for the Alstom GT13E2 is detailed in Table 6.5:

Location	Fuel Type	Owner's Contingency Cost (€m)
Northern Ireland	Distillate	€4,725,000
	Dual Fuel	€4,780,000
Republic of Ireland	Distillate	€4,785,000
	Dual Fuel	€4,845,000

Table 6.5 – Summary of Owners Contingency costs for Alstom GT13E2

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

CEPA/Ram have estimated the costs associated with Financing and Construction Insurance as a percentage of the EPC costs while the Interest During Construction (IDC) estimate is based on their project experience and is calculated on a jurisdictional basis. These are summarised in Table 6.6.

	Total Cost for Distillate (€)	Total Cost for Duel Fuel (€)
Financing NI	€1,890,000	€1,912,000
Financing RoI	€1,914,000	€1,938,000
IDC NI	€848,614	€880,483
IDC RoI	€1,108,885	€1,152,878
Construction Insurance NI	€850,500	€860,400
Construction Insurance RoI	€861,300	€872,100

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

6.7 INITIAL FUEL WORKING CAPITAL

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

CEPA/Ram has estimated an initial fuel storage fill cost of €3.63m for a distillate plant and €3.06m for a dual fuel plant. This is based on a requirement to run for 72 hours full load, an additional 0.5 days of commercial running and an oil price of US$58.13/ barrel[9]. It is assumed that unused fuel is sold back at the end of the plant life. Consistent with the 2013 BNE decision, excise duty has also been added to fuel costs for NI plant.

The cost estimate for fuel working capital is provided in the table below.

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Fuel working capital	€3,638,868	€3,057,014

Table 6.7 – *Summary of Fuel Working Capital*

6.8 OTHER NON-EPC COSTS

CEPA/Ram grouped the remaining costs together to allow a logical comparison of the data they held on their project experiences. The cost areas included under ‘Other Non-EPC Costs’ include EIA, legal, owner’s general and administration, owner’s engineer, start-up utilities,

[9] Oil price used by CEPA was ICE Brent Crude as traded on 12 March 2015 (source Bloomberg)

commissioning, O&M mobilisation, spare parts and working capital. Based on CEPA/Ram's experience, the Other Non-EPC Costs equates to 9.0% of the EPC Costs.

As with the calculation for 2013 the data used in calculating the percentage allocation for Other Non-EPC Costs was presented to the SEM Committee but due to confidentiality, the derivation of this percentage allocation cannot be included in this paper. The SEM Committee are satisfied with the approach taken by CEPA/Ram in determining the Other Non-EPC Costs.

Location	Fuel type	Other non-EPC costs (€)
Northern Ireland	Distillate	€8,505,000
	Dual Fuel	€8,604,000
Republic of Ireland	Distillate	€8,613,000
	Dual Fuel	€8,721,000

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

6.9 MARKET ACCESSION AND PARTICIPATION FEES

Similar to previous years, the required fees to enter the SEM were considered. Based on the current tariffs, these will cost €3,654 and although small are included for completeness. These charges are payable to the market operator, SEMO.

Type of charge	Charge Cost (€)
Accession Fee	€1,044
Participation Fee	€2,610

Table 6.9 – *Summary of Market Fees*

6.10 RECURRING COST ESTIMATES

In addition to identifying investment costs, it is necessary to consider the recurring costs that the BNE plant will face. This includes:

- Market operator and electricity transmission use of system charges;
- Operation and maintenance costs;
- Insurance; and
- Business rates.

Following the SEM Committee decision[10] on the treatment of gas transportation capacity costs in the bidding code of practice for the SEM, CEPA/Ram expect that these costs would now be expected to be included in energy market bids for the BNE plant. Gas transportation costs in their entirety (both usage and capacity components) have been excluded from the BNE calculation for this year.

6.11 MARKET OPERATOR CHARGES

As part of its role in the administration of the market, there are charges which SEMO must levy in order to recover its own allowed costs and allowed market related costs. These charges consist of:

- Imperfections Charge,
- Market Operator Tariffs,
- Generator Under Test Tariff.

For the purposes of the BNE, only Market Operator Tariffs are relevant.

Table 6.11 provides the estimate of the Market Operator charges which would apply to the BNE peaking plant:

Type of charge	Charge amount	Total Cost
Fixed market operator tariffs	€ 47.00/MW	Distillate - €9,198 Dual - €9,583

Table 6.11: Market operator Charges

[10] See SEM Committee (2014): 'Decision paper on Treatment of Gas Transportation Capacity Costs and Modification to the Bidding Code of Practice'

6.12 TRANSMISSION USE OF SYSTEM CHARGES

The development of harmonised all-island electricity transmission generator use of system charges was an objective stated in the original 2005 SEM high level design. A harmonised regime came into force in 2012[11] following the SEM Committee's decision paper on all-island generator TNUoS charges.

For the BNE 2016 calculation, CEPA decided to use:

- the average locational G-TNUoS tariff that applies today for existing NI sites; and
- the average locational TNUoS tariff that applies today for existing RoI sites,

for the notional NI and RoI site respectively.[12] The estimates of electricity transmission generation charges are summarised in Table 6.12 below.

Location	Fuel Type	TUoS charge (€)
NI	Distillate	€807,634
	Dual Fuel	€841,475
RoI	Distillate	€1,359,144
	Dual Fuel	€1,416,094

Table 6.12: Generator TUoS charges

6.13 OPERATION AND MAINTAINENCE COSTS

As with previous BNE calculations, the plant is assumed to be operated by multi-skilled staff capable of running the plant and performing activities that are not covered by the Long Term Service Agreement (LTSA). Five shifts of two multi-skilled operators have been assumed, together with an allocation for general and administration costs, amounting to an estimated €480,000 per year. Consistent with the approach used in previous years, any differences between locations (such as, for example, labour rates) have not been considered.

The fixed annualised LTSA maintenance costs of the plant are based on the minimum maintenance regime for the GT13E2 recommended by Alstom for units running less than 3000 Equivalent Operating Hours per year. Recent LTSA costs for a GT13E2 plant have been reviewed and there does not appear to be a significant move in the prices. For the distillate option, the fixed annualised LTSA maintenance costs amount to an estimated €1,460,000 and for the dual fuel option, €1,490,000.

[11] SEM Committee (2012): 'All-island Generator Transmission Use of System (TUoS) Charges

[12] Sourced from EirGrid 14/15 Proposed Generator TUoS v10.

The table below shows the fixed operation and maintenance costs

Fuel type	O&M Costs (€)
Distillate	€1,940,000
Dual fuel	€1,970,000

6.14 SUMMARY OF INVESTMENT COSTS

The table below summarises all the investment cost (in €m) for the Alstom GT13E2 for each jurisdiction and for each fuel type.

Cost Item	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
EPC Costs	€94.500	€95.600	€95.700	€96.900
Site Procurement	€0.959	€0.950	€0.767	€0.760
Electrical connection Costs	€10.529	€10.529	€6.970	€6.970
Water connection	€0.490	€0.490	€0.490	€0.490
Gas connection	€0.000	€3.620	€0.000	€3.620
Owners Contingency	€4.725	€4.780	€4.785	€4.845
Financing Costs	€1.890	€1.912	€1.914	€1.938
Interest During Construction	€0.849	€0.880	€1.109	€1.153
Construction Insurance	€0.851	€0.860	€0.861	€0.872
Initial Fuel working capital	€3.639	€3.057	€2.962	€2.488
Other non EPC Costs	€8.505	€8.604	€8.613	€8.721
Accession fees	€0.001	€0.001	€0.000	€0.000
Participation Fees	€0.003	€0.003	€0.000	€0.000
Total	**€126.940**	**€131.286**	**€124.171**	**€128.757**

Table 6.14 – *Summary of Investment Costs for Alstom* GT13E2 (€m)

The Proposed Fuel Option for the BNE is Distillate

7 ECONOMIC & FINANCIAL PARAMETERS

7.1 INTRODUCTION

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

7.2 NATURE OF THE BNE INVESTMENT

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

Area	Assumption
Type of Investor	It is assumed that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level for the peaking plant investment project in the forthcoming year. In addition, it is assumed that the BNE is a green-field investment with no existing assets and associated financing costs.
Plant Life	The economic life of the project has been taken as 20 years.
Financing Structure	It is assumed that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Therefore it is assumed that an average tenor of 10 years on the new debt. It is also assumed that the investor would seek to maximise the debt/equity ratio, but that in the current financial markets this would mean a gearing ratio of 60%.
Credit Quality	It is assumed that a BNE investor has an investment grade credit rating in the range BBB to A

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

7.3 WEIGHTED-AVERAGE COST OF CAPITAL

Annex B of the CEPA report provides a comprehensive summary of the assumptions used in their recommendation of the WACC to be used for the BNE Peaker for 2016. In summary, CEPA recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 3.77% - 4.98% in the Republic of Ireland and 3.93% - 5.05% in the UK.

The SEM Committee have used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2016. The below table shows the low and high WACC values obtained by CEPA in both the 2016 and 2013 calculations of the BNE process:

	Republic of Ireland		**Northern Ireland**	
	Weighted Average Cost of Capital			
	Low	High	Low	High
2013	**7.52%**	**10.44%**	**5.88%**	**7.32%**
2016	**3.66%**	**5.38%**	**3.70%**	**5.23%**

As with previous years' methodology, the mid-point of the WACC has been chosen as the absolute representative value. The table below shows the chosen values in both BNE processes:

	WACC	
	2013	2016
Northern Ireland	**6.60%**	**4.46%**
Republic of Ireland	**8.98%**	**4.52%**

8 INFRA MARGINAL RENT

Infra-Marginal Rent is deducted from the BNE using the following formula:

IMR DEDUCTED IN €/KW = [(PCAP – BID[13])/1000] * OUTAGE TIME * (1 – FOP)

where Bid is the Bid Price of the BNE Peaking plant, PCAP is the SEM Price Cap (€1000/MWh), FOP is Forced Outage Probability, and Outage Time is the duration of lost load under the Generation Security Standard. Both of the latter parameters are matched to the corresponding settings in the Capacity Requirement discussed later in the paper.

The Bid value was derived from the average bid of existing distillate peakers in the SEM on 31 March 2015. The bid price used in the calculation is a mean value of prices that were bid into the market from suitable plants (firing distillate fuel) on that day. Where a plant is located in Northern Ireland, an appropriate exchange rate conversion was applied. The resulting Infra-Marginal Rent to be deducted is:

IMR DEDUCTED IN €/KW = [(1000 – 189.7)/1000] * 8 * (1 – 5.91%)

= €6.10/KW

While it may be possible to compile an alternative value for the bid from forward curves for oil prices, the decision to use the standing bid data observed in the SEM is consistent with previous exercises and is not considered to be a material or biasing assumption.

It is proposed that the IMR figure presented in this section will be recalculated for the 2017 ACPS, using updated bid data.

9 ANCILLARY SERVICES

A plant entering the SEM in 2016 would be expected to earn AS revenues for part of the year under the existing harmonised all-island arrangements for AS (HAS) introduced in 2010. However, as part of the DS3 programme, the SEM Committee is developing new arrangements for AS for which a budget has been set for future trading years that will commence in October 2016.

[13] Source: Average Bid of Distillate Peaker in the SEM on 31/03/2015

Revenues for the BNE plant may be higher under DS3 than under HAS, however, the higher revenues will come via a ramping up in the budget for DS3 over a number of years to 2020. As a simplifying assumption therefore, AS revenues for the BNE entering the market in 2016 have been calculated as though the HAS rates were in place all year.

It is worth noting that the DS3 framework offers more services than the current HAS arrangements. In light of this, the BNE Peaking Plant may be expected to have additional revenue opportunities in 2017. It is proposed that this aspect be reviewed for the calculation of the 2017 ACPS.

The existing HAS arrangements using the proposed rates and charges are set out in EirGrid's February 2015 consultation.[14] This follows the same calculation process as adopted in the 2013 BNE consultation and decision papers.

***Table 9.1** – Summary of Ancillary Services Costs for 2016*

Cost Item	Not Running (€/TP)	Running (€/TP)
Primary Operating Reserve		25.02
Secondary Operating Reserve		40.18
Tertiary Operating Reserve 1		33.10
Tertiary Operating Reserve 2		16.46
Replacement Reserve		7.83
Reactive Power (Leading)	52.84	8.40
Reactive Power (Lagging)		19.16
Total Revenue	**52.84**	**150.15**

The potential AS income using assumptions of 95% availability and 2% running hours for BNE plant is:

$$(52.84 \times 0.95 \times 48 \times 365) + (150.15 * 0.02 * 48 * 365) = €932,082$$

In the 2013 BNE decision paper, the SEM Committee also clarified the applied penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events. A 195.7MW direct trip and a 195.7MW SND at zero notice time gives:

- Trip charge = €10,624
- SND (2014/15 rates) = €13,973

[14] http://www.eirgrid.com/media/HAS_ConsultationPaper2015-2016v1.pdf

This gives a value of AS revenues that the BNE peaking plant for 2016 would achieve under the current harmonised AS framework of €907,485.

10 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2016

CEPA/Ram's pre-tax WACC model was run using the fixed cost schedule in Table 6.14 and WACC settings in section 7.3 for each of NI and RoI. Expressed in /kW/yr terms, the fixed costs of the investment were calculated as:

- In NI **€76.24/kW/yr**
- In RoI **€82.31/kW/yr**

The Proposed Best New Entrant Peaker for 2016 is the Alstom GT13E2, located in Northern Ireland

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2016. This includes the deduction of any revenues obtained from Infra-marginal Rent or Ancillary Services.

Cost Item	Northern Ireland Distillate
Annualised Cost per kW	€76.24/kW
Ancillary Services	€4.64/kW
Infra-marginal Rent	€6.10/kW
BNE Cost per kW	**€65.50/kW**

Table 10.1 – *Final costs for BNE Peaker for 2016*

10.1 DEDUCTIONS FOR THE BNE PEAKING PLANT 2017

It is proposed that the BNE value for the 2017 ACPS calculation will be derived from an indexing of the 2016 figure in similar fashion to exercises for the 2015 and 2016 ACPS, but the Harmonised Ancillary Services deduction will be replaced by a suitable deduction for Ancillary Service revues under the DS3 programme.

11 CAPACITY REQUIREMENT FOR 2016

11.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2016 is the same as that used in previous years' calculations.

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

11.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

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

A Decision Paper was published in February 2007 which set out the SEM Committee' decisions on the contents of the August 2006 Consultation Paper. This Decision Paper laid out the key methodology and individual data point assumptions. These parameters were used in calculating the 2007 - 2014 Capacity Requirement.

In subsequent years the methodology had not changed and is repeated once again for the 2016 Capacity requirement.

11.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2016

As anticipated in the initial consultation and decision papers, the same parameter settings have been used in the calculation for the 2016 Capacity Requirement. The following sections describe further each of these parameters.

11.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the SEM Committee stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the SEM Committee subsequently decided on a GSS of 8 hours Loss of Load Expectation per annum. The GSS of 8 hours has been retained by the SEM Committee for the 2016 calculation.

11.3.2 DEMAND FORECAST

Considering the reductions in demand in recent years, the SEM Committee have worked closely with both TSOs in determining a suitable forecast for 2016. Recent demand trends and economic forecasts were also used in the analysis.

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

	2013 Forecast Total Energy Requirement	2016 Forecast Total Energy Requirement
Republic of Ireland	27846	27449
Northern Ireland	9476	9194

Table 14.1 – *Forecasted Total Energy Requirement*

For the purposes of calculating the Capacity Requirement, the forecast was taken from the medium table of the Eirgrid / SONI forecast. Backup information can be found in Chapter 2 of the Eirgrid / SONI All-island Generation Capacity Statement 2015-2024[15].

This demand forecast may be recalculated before the final decision on the capacity requirement and is illustrated below:

[15] http://www.soni.ltd.uk/media/documents/Operations/CapacityStatements/All%20Island%20Generation%20Capacity%20Statement%202015%20-%202024.pdf

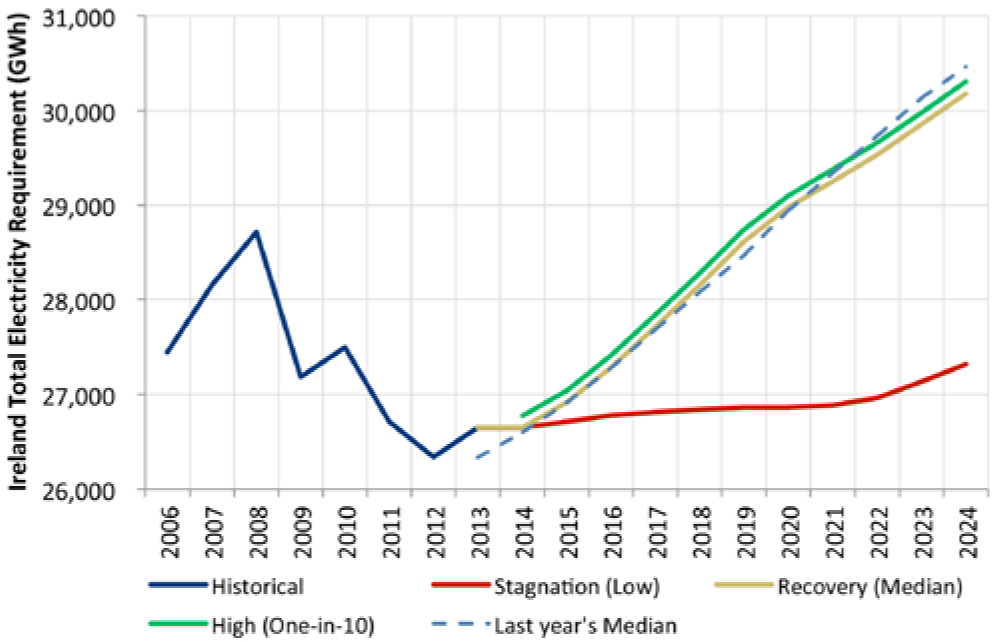

Figure 11.1 – *Ireland Total Electricity Requirement*[16].

The figure shows that a return to 2008 demand levels is not expected until after 2018.

For the 2016 Capacity Requirement calculation, the TSOs were asked to provide half-hourly demand forecast profiles. Care was exercised to ensure that the jurisdictional traces were harmonised and day-shifted to align on a day-by-day basis. The Sent-Out Load Trace is forecasted from the base year 2007 and using the forecasted growths from the latest Generation Capacity Statement 2015-2024 and the Wind Forecast profile for 2016 is forecasted from the base year, 2013. The Regulatory Authorities assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the ADCAL calculation engine (described below).

11.3.3 GENERATION CAPACITY

Similar to the previous years' Capacity Requirement calculations, the generation capacity data was already available to the Regulatory Authorities. The data was also discussed with the TSOs as needed. For the BNE Decision paper, the SEM Committee are minded to use the 2015-16 Validated Directed Contracts database that is currently being processed to source this data.

[16] Chart obtained from Eirgrid/SONI – Page 8 - All-island Generation Capacity Statement 2015-2024

11.3.4 SCHEDULED OUTAGES

In the Decision Paper AIP/SEM/07/13 it was decided that scheduled outages for thermal plant would be quantified based on the previous five years of unit set data, and that the ADCAL algorithm would be permitted to efficiently schedule these outages during the calendar year. This process has continued to be applied in formulating the scheduled outage inputs for each unit in the 2016 Capacity Requirement process.

11.3.5 FORCED OUTAGE PROBABILITIES

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

As described in Section 4 above and in the Decision Paper on the CPM Medium Term review, the SEM Committee have decided to amend the FOP to **5.91%,** this number has been used for the 2016 BNE Calculation.

11.3.6 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explains the SEM Committee's decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2016 process. Individual wind output traces were provided by the TSOs. The wind traces were built upon the same reference year and aligned on a day-by-day basis with the load traces described earlier.

11.3.7 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2016 Capacity Requirement.

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

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

1. Use ADCAL to calculate the Loss of Load Expectation (LOLE) for 2016 that arises from the conventional market capacity, employed to meet the 2016 load trace with wind output netted from this trace.

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

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

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

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

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

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

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

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

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

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

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

11.4 PROPOSED CAPACITY REQUIREMENT FOR 2016

The inputs used in the 2016 consultation calculations are summarised below. The derivation of these input parameters will be published on the AIP website alongside this consultation paper in spreadsheet form as per previous exercises.

Input	Description
Load Forecasts for ROI and NI for 2016	A combined load forecast for 2016, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The period used for analysis was 1 January 2016 to 31 December 2016. Two traces were agreed: 1) Total Load Forecast for 2016 2) Total (In Market) Conventional Load Forecast See Appendix 5 – Load Forecast for 2016
Generation Capacity	A list of all generation to be in place in 2016 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2016, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). Dublin Waste to Energy and Note OCGT were not included in the model. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9748 MW**
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 2016 used was **3464 MW**. This results in a Capacity Credit of **0.117**. The Time Weighted Market Wind Capacity in 2016 was **2729 MW**. Therefore the Wind Capacity Credit is derived as **319 MW** (2729 x 0.117)

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.
Force Outage Probability (FOP)	In line with the SEM Committee decision on the CPM Medium Term Review, the FOP remains at 5.91%.
Generation Security Standard (GSS)	The SEM Committee maintained the value of **8 hours** for the GSS.

Table 11.1 – *Summary of Inputs into Adcal Model*

As a result of the analysis carried out in conjunction with the TSOs, the SEM Committee have determined that the Capacity Requirement for 2016 is **7070 MW**

The Proposed Capacity Requirement for 2016 is 7070 MW

12 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2016

Multiplying the annualised fixed cost of the BNE Peaker by the Capacity Requirement yields:

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2016	65.50	7070	463,103,448

Table 12.1 – ACPS for the Trading Year 2016

The Proposed Annual Capacity Payments Sum (ACPS) for 2016 is €463,103,448

13 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to Kevin Baron at Kevin.Baron@uregni.gov.uk by **5pm on 12 June 2015**.

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

The project team will endeavour to facilitate requests for bilateral meetings with interested parties ahead of the above deadline, and/or within reason following the receipt of responses. Such requests should be lodged as per the contact details above.

APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS

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

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2007	64.73	6,960	450,517,348
2008	79.77	7,211	575,221,470
2009	87.12	7,356	640,854,720
2010	80.74	6,826	551,133,375
2011	78.73	6,922	544,956,545
2012	76.34	6,918	528,120,120
2013	78.18	6,778	529,876,722
2014	80.27	7,049	565,819,301
2015	81.60	7,046	574,953,600

Table A1.1 – ACPS for Previous Trading Years

APPENDIX 2 – COMPARISON WITH 2013 BNE PEAKING PLANT

The table below shows a comparison of the costs for the 2013 and 2016 BNE Peaker Calculations.

Table A2.1 – Comparison of Costs for the 2013 and 2016 BNE Peaker

Investment Costs (€)	2013 Consultation	2016 Consultation	Difference	% Difference	
EPC Costs	92,500,000	94,500,000	2,000,000	2.16%	EPC Costs have been modelled using the latest release of GT PRO Version 24. The BEAMA cost index gives an indication that costs over the last 12 months have increased by approximately 2%. The addition of unpredictable sources of power generation such as wind power has increased developers' interests away from large CCGT plant toward smaller simple cycle plant, so the cost of simple cycle plant may rise at a higher rate than CCGTs, particularly with aero-derivative GTs.
Site Procurement	1,529,154	959,078	-570,076	-37.28%	CEPA have based their assessment of site procurement costs on the land values in NI as a whole.
Electrical connection Costs	7,870,000	10,529,100	2,659,100	33.79%	The approach by CEPA is to use the cost estimates provided in the SONI Transmission Charging Methodology Statement (2008)
Water connection	0	490,000	490,000		In recent BNE determinations, the Belfast West site had an existing water connection. However, CEPA now require an estimation for the whole of NI
Gas connection	0	0	0	0	Rationale as above.
Owners Contingency	4,810,000	4,725,000	-85,000	-1.77%	This has been set to 5.0% of EPC costs, down from 5.2% in 2013.
Financing Costs	1,850,000	1,890,000	40,000	2.16%	This has been set as a proportion of EPC costs based on previous experience.
IDC	2,204,216	848,614	-1,355,602	-61.50%	This is a combination of increased EPC costs and increased borrowing costs.
Construction Insurance	832,500	850,500	18,000	2.16%	This has been set as a proportion of EPC costs based on previous experience.

Initial Fuel working capital	5,044,812	3,638,868	-1,405,944	-27.87%	Decrease in Initial Fuel Working capital is associated with the change in the Oil Price. In the 2012 Decision paper the price of oil was $119/barrel and the exchange rate was approx. 0.706$/€. For the 2016 calculation, the price of oil was $57.54/barrel with an exchange rate of approx. 0.71$/€.
Other non EPC Costs	8,325,000	8,505,000	180,000	2.16%	This has been set as a proportion of EPC costs based on previous experience.
Accession & Participation Fees	3,903	3,654	-249	-6.38%	Slight change
Total	124,969,585	126,939,814	1,970,229	1.58%	Overall the Capital costs for the BNE peaker has increased. This is mainly due to the increase in Connection Costs.

Recurring Costs (€m)	2013 Consultation	2016Consultation	Difference	% Difference	
Transmission & Market Operator charges	1.168	0.817	-0.351	-30.05%	Slight Change
Gas Transmission Charges	0	0	0	0.00%	No change
Operation and maintenance costs	1.902	1.940	0.038	2.0%	The fixed LTSA maintenance costs have increased by over 2%
Insurance	1.480	1.512	0.032	2.16%	Based on a percentage of EPC costs
Business Rates	0.70	0.753	0.053	7.57%	The reason for this increase is due to a combination of increased business rates, increased capacity of the BNE and movement in exchange rate
Fuel working capital (ongoing)	0.33	0.165	-0.165	-450%	Driven by changes in underlying fuel prices and in the WACC
Total	5.58	5.187	-0.393	-7.04%	

APPENDIX 3 – LOW/MEDIUM/HIGH DEMAND FORECAST

Med	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,648	0.0%	9,011	0.0%	35,659	0.0%	4,915	1,732	6,627	4,818	1,694	6,492
2015	26,915	1.0%	9,074	0.7%	35,989	0.9%	4,929	1,734	6,643	4,831	1,694	6,505
2016	27,286	1.4%	9,146	0.8%	36,432	1.2%	4,953	1,738	6,671	4,856	1,696	6,532
2017	27,715	1.6%	9,219	0.8%	36,934	1.4%	4,978	1,744	6,702	4,881	1,700	6,561
2018	28,152	1.6%	9,293	0.8%	37,445	1.4%	4,995	1,752	6,727	4,898	1,707	6,585
2019	28,613	1.6%	9,368	0.8%	37,981	1.4%	5,016	1,762	6,758	4,919	1,716	6,614
2020	28,973	1.3%	9,443	0.8%	38,416	1.1%	5,036	1,774	6,790	4,939	1,727	6,646
2021	29,250	1.0%	9,518	0.8%	38,768	0.9%	5,056	1,787	6,823	4,959	1,739	6,678
2022	29,532	1.0%	9,594	0.8%	39,126	0.9%	5,096	1,799	6,875	4,999	1,750	6,729
2023	29,852	1.1%	9,671	0.8%	39,523	1.0%	5,143	1,811	6,934	5,045	1,762	6,788
2024	30,179	1.1%	9,748	0.8%	39,927	1.0%	5,190	1,824	6,994	5,093	1,774	6,847

TableA3-1: Median Demand Forecast

Low	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,648	0.0%	8,934	-0.8%	35,582	-0.2%	4,915	1,727	6,621	4,818	1,688	6,486
2015	26,714	0.2%	8,892	-0.5%	35,607	0.1%	4,915	1,723	6,618	4,818	1,682	6,480
2016	26,780	0.2%	8,884	-0.1%	35,664	0.2%	4,915	1,720	6,616	4,818	1,678	6,476
2017	26,809	0.1%	8,898	0.2%	35,707	0.1%	4,916	1,720	6,616	4,819	1,676	6,474
2018	26,837	0.1%	8,917	0.2%	35,755	0.1%	4,916	1,722	6,619	4,819	1,677	6,476
2019	26,861	0.1%	8,943	0.3%	35,804	0.1%	4,917	1,726	6,622	4,819	1,679	6,479
2020	26,861	0.0%	8,975	0.4%	35,836	0.1%	4,917	1,731	6,628	4,820	1,684	6,483
2021	26,884	0.1%	9,022	0.5%	35,906	0.2%	4,917	1,736	6,632	4,820	1,688	6,488
2022	26,963	0.3%	9,069	0.5%	36,032	0.4%	4,921	1,741	6,642	4,824	1,692	6,496
2023	27,137	0.6%	9,116	0.5%	36,252	0.6%	4,943	1,746	6,668	4,845	1,697	6,522
2024	27,317	0.7%	9,164	0.5%	36,481	0.6%	4,965	1,751	6,696	4,868	1,701	6,549

Table A3-2: Low Demand Forecast

High	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2014	26,774	0.5%	9,096	1.0%	35,869	0.6%	5,083	1,749	6,812	4,986	1,711	6,677
2015	27,041	1.0%	9,189	1.0%	36,230	1.0%	5,097	1,757	6,834	5,000	1,716	6,696
2016	27,412	1.4%	9,294	1.1%	36,706	1.3%	5,122	1,767	6,869	5,025	1,725	6,729
2017	27,841	1.6%	9,401	1.1%	37,241	1.5%	5,146	1,780	6,906	5,049	1,735	6,765
2018	28,278	1.6%	9,509	1.2%	37,787	1.5%	5,164	1,794	6,938	5,067	1,749	6,796
2019	28,739	1.6%	9,623	1.2%	38,362	1.5%	5,184	1,812	6,976	5,087	1,766	6,833
2020	29,099	1.3%	9,728	1.1%	38,826	1.2%	5,204	1,830	7,015	5,107	1,783	6,870
2021	29,376	1.0%	9,833	1.1%	39,208	1.0%	5,225	1,848	7,053	5,127	1,801	6,908
2022	29,658	1.0%	9,939	1.1%	39,596	1.0%	5,264	1,866	7,111	5,167	1,818	6,965
2023	29,978	1.1%	10,046	1.1%	40,024	1.1%	5,311	1,885	7,176	5,214	1,836	7,030
2024	30,305	1.1%	10,155	1.1%	40,460	1.1%	5,359	1,904	7,242	5,261	1,854	7,095

Table A3-3 High Demand Forecast

APPENDIX 4 – CEPA'S REPORT TO SEM COMMITTEE ON FIXED COSTS OF A BNE PEAKING PLANT FOR 2016

Available on the AIP website[17].

[17] http://www.allislandproject.org/en/capacity_overview.aspx