Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum For Trading Year 2017

Consultation Paper

18 May 2016

SEM-16-026

1 EXECUTIVE SUMMARY

The Capacity Payment Mechanism is a fixed revenue mechanism which collects a pre-determined amount of money from suppliers. These funds are paid to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code. The value of this 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 peaking plant.

The Best New Entrant ("**BNE**") peaking plant is an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland. This was determined as part of the calculation of the Annual Capacity Payment Sum ("**ACPS**") for 2016[1]. In accordance with the decision described in the 2016 Final Decision paper, its costs have been fixed and indexed for 2017.

The annualised fixed cost determined for the 2016 ACPS was €83.74 /kW/year. When this is adjusted for inflation[2] the 2017 annualised cost is €85.08/kW/year. Once infra-marginal rent and ancillary services are deducted the annualised cost is €70.99/kW/year.

The Capacity Requirement for 2017, calculated using a similar methodology to previous years, is 7267 MW.

The product of these price and quantity elements yields an ACPS for 2017 of €515,884,330. This compares to an ACPS of €514,837,400 for the 2016 capacity year.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2017	70.99	7267	515,884,330

Table 1 – Executive Summary ACPS 2017

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[1] See the Annual Capacity Payment Sum 2016 Final Decision Paper https://www.semcommittee.com/publication/sem-15-059-acps-final-decision-paper

[2] The Retail Price index (RPI) figure of 1.6% used here is the March 2016 figure (published 12 April 2016), the time series can be found at https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

It is important to note here that the new I-SEM will go live in Q4 2017 and as such the current Capacity Payment Mechanism will discontinue in October 2017. As such, the RAs have published the Capacity Period Payment Sum ("**CPPS**") for 2017 to indicate the monthly sums to be paid for the period Q1 2017- Q3 2017 ahead of I-SEM Go-Live:

Month	Capacity Payment Period Sum 2017
January	€52,528,632
February	€50,835,766
March	€46,925,877
April	€39,121,029
May	€36,236,557
June	€34,256,102
July	€32,505,450
August	€35,729,847
September	€35,696,498
October	€45,104,783
November	€52,217,636
December	€54,726,154
Total	**€515,884,330**

Table 2 – Capacity Payment Period Sum 2017

Table of Contents

2 Introduction

On 1 November 2007 the Single Electricity Market ("**SEM**"), the new all-island arrangements for the trading of wholesale electricity, was introduced. 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 suppliers and pays these funds to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code ("**TSC**")[3]. 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.

In May 2005 the Northern Ireland Authority for Utility Regulation ("**the Utility Regulator**") and the Commission for Energy Regulation ("**CER**") (together the Regulatory Authorities ("**RAs**")) set out the options for the CPM. The RAs indicated their proposal to develop a fixed revenue CPM that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code.

In March 2006 a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of alternative options for the CPM. This paper re-iterated the proposed outline of the CPM 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. It proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator.

The RAs 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

[3] http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx

well as the estimated revenues the plant may derive through its operation in the ancillary services markets.

The same process has been used for the calculation of the fixed costs of a BNE peaking plant for all subsequent years. The Annual Capacity Payment Sums for all previous years are summarised in Appendix 1 of this paper.

On 9 March 2009 the SEM Committee ("**SEMC**") published a consultation paper titled ***Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper*** (SEM-09-023). The purpose of the consultation paper was to propose options to address a key concern raised by industry participants regarding the stability of the Annual Capacity Payment Sum due to the annual determination of the Best New Entrant Fixed Cost. In the paper, the SEMC signalled its intention to carry out a further review of the CPM in the medium term. The main purpose of the review was to examine if the current design of the CPM could be further improved to better meet the CPM objectives. This review concluded in March 2012 when the SEMC published the final decision paper on the CPM Medium Term Review (SEM-12-016).

Following the Medium Term Review the SEMC decided that the BNE element of the ACPS calculation should be fixed and indexed for three years, ending the fixedness in 2015. The 2016 calculation was constructed from the ground up through the (usual) re-evaluation of the Capacity Requirement but also the BNE figure was calculated from first principles, through the contracted consultants Cambridge Economic Policy Associates (CEPA).

The SEM Committee published the consultation paper on 29 May 2015 along with the CEPA paper outlining the BNE figure. The consultation paper included proposed once again fixing the BNE element for the Trading Year 2017 to provide stability to generators in light of the SEM ending as the new I-SEM goes live in 2017. The decision paper was then published on 4 September 2016 (SEM-15-059). It was decided within the decision paper that the BNE element will be the inflated through the Retail Price Index ("**RPI**") for 2017. The SEM Committee approved to inflate through the RPI rather than the previously used Consumer Price Index ("**CPI**"). The deduction for System Services revenues will be implemented for 2017 using estimated DS3 revenues which supplants the previously deducted Harmonised Ancillary Services ("**HAS**").

3 Best New Entrant Peaking Plant Price for 2017

In the decision paper on the Fixed Cost of a BNE peaking plant, Capacity Requirement and Annual Capacity Payment Sum for the Calendar Year 2016[4], the BNE for 2016 and 2017 was determined as an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

The table below provides a summary of the final annualised costs of the BNE Peaker for 2015 and 2016 with the proposed 2017 figures. This includes the deduction of any revenues obtained from Infra Marginal Rent, and Ancillary Services.

	Decision 2015	Decision 2016	Proposed 2017
Annualised Cost per kW per year	91.88	83.74	85.08
Ancillary Services	4.53	4.64	N/A
DS3 Revenues	N/A	N/A	7.67
Infra-Marginal Rent	5.75	6.28	6.42
BNE Cost per kW per year	**81.60**	**72.82**	**70.99**

Table 3 – BNE Provisional Prices

3.1 INDEXATION OF BNE ANNUALISED COST

In the 2015 decision paper it was approved by the SEM Committee that the BNE element of the ACPS should be fixed for the final year of the SEM. Since the SEM will become the new I-SEM in Q4 2017, the BNE figure will not be recalculated in 2016 but inflated by an appropriate index. The 2013 BNE figure was fixed for three years and inflated in 2014 and 2015 by CPI. During those years (2007-13) where the BNE figure was determined from the ground up, the calculation of the Weighted Average Cost of Capital ("**WACC**") required as an input an estimate of the cost of debt figure. Within this cost of debt determination, the deflation of nominal to real yields on UK Government bonds was determined through deflation by RPI. The indexation of the BNE figure (when fixing for three years from 2013) used CPI.

Following the 2016 calculation, participants noted that since the conversion of nominal to real yields on UK bonds was through RPI then the BNE figure should be also be inflated using the same index. The SEM Committee agreed and approved this change for the 2017 calculation.

As the BNE is located in Northern Ireland, the RPI as measured in the UK will be used to index the BNE annualised cost.

[4] http://www.semcommittee.eu/en/cp_decision_documents.aspx?article=879633f4-5b08-42e3-a889-4f86cf0b2667

When determining this calculation the most recent inflation data available for RPI in the UK showed that average prices in the UK increased by 1.6% between March 2015 and March 2016[5]. This will be re-calculated prior to decision to account for inflation between June 2015 and June 2016[6].

3.2 DEDUCTION FOR INFRAMARGINAL RENT

The deduction for Inframarginal Rent ("**IMR**") will be calculated using the following formula that was set out in the CPM Mid Term Review:

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

For indicative purposes, the deduction for infra-marginal rent has been calculated according to generator commercial offer data on 26 March 2016. The bid figure determined on this day was 146.57 €/MWhr. This will be re-calculated post-consultation in late May ahead of the final decision.

For comparison, the graph below shows the average distillate bid price used in the IMR deduction as a trace over the last three evaluations. It clearly shows how the average bid price falls with the price of distillate oil (shown in the vertical axis) over time (shown in the horizontal axis).

[5]For the latest RPI figures used in this calculation, see the relevant pages from the Office of National Statistics http://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

[6] The release calendar for UK Indices can be found here http://www.ons.gov.uk/releasecalendar

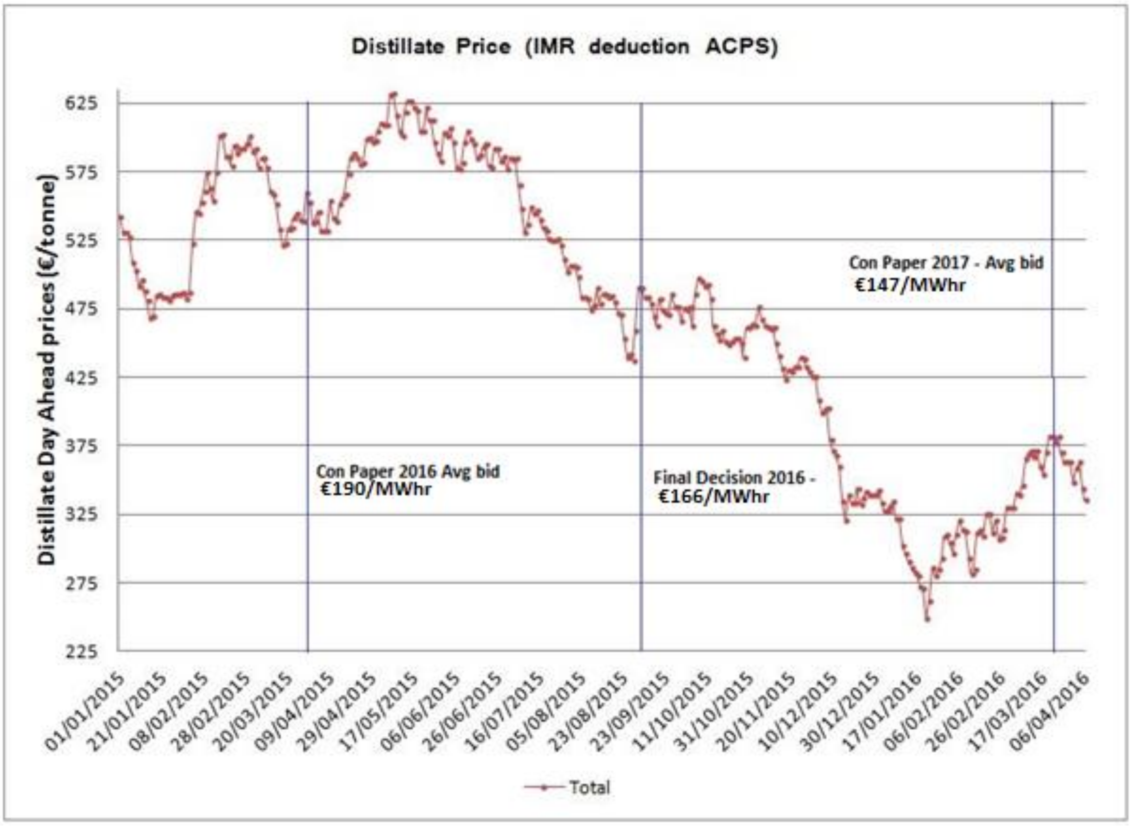

Figure 1 – Distillate Price used in IMR calculations

3.3 ANCILLARY SERVICES DEDUCTION

Since SEM Go-Live in November 2007, the BNE fixed costs have been reduced by the earnings received in relation to Ancillary Services ("**AS**"). The current 2016 ACPS was the last time that revenues from HAS would be deducted as the System Services earnings are supplanted by the new DS3 services for 2017.

Through work with the TSOs, the RAs have determined that the deduction from DS3 will be €7.67/kW/year. To show how the ACPS would change if the existing HAS arrangements were still in place for 2017, the RAs have constructed the following table which shows the "savings" from higher DS3 payments in 2017.

	Proposed 2017	Comparable 2017*
Annualised Cost per kW per year	85.08	85.08
Ancillary Services	N/A	4.73
DS3 Revenues	7.67	N/A
Infra-Marginal Rent	6.42	6.42
BNE Cost per kW per year	**70.99**	**73.93**
Capacity Requirement 2017	**7267**	**7267**
ACPS 2017 (proposed & dummy)	**€515,884,330**	**€537,228,962**
Reduction in ACPS due to DS3		**€21,344,632**

Table 4 – Reduction in ACPS due to DS3

The figure of the 4.73 €/kW/year for the 2017 comparable HAS deduction was found by inflating the 2016 HAS figure (4.54 €/kW/year) by a nominal 2%. As can be seen, the ACPS for 2017 would be of the order of €537.2m if the existing HAS arrangements were continuing for the Trading Year 2017.

The TSOs provided information on the capabilities per service that the Alstom GT13E2 can provide under DS3, the RAs then formulated the appropriate deduction. The table in Appendix 3 shows the capability of the Alstom GT13E2 along with the current interim tariff rates (currently in a period of consultation[7]) and the expected revenues for each DS3 service.

The €7.67/kW was based on the interim tariffs for DS3 and should these tariffs change at the Final Decision stage, the figure above will be recalculated.

4 Capacity Requirement for 2017

4.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2017 is the same as used in previous years' calculations. This section details the individual components and the calculations that have been performed in evaluating this input to the ACPS 2017 figure.

[7] interim Tariffs consultation paper DS3 http://www.eirgridgroup.com/site-files/library/EirGrid/OPI_INV_Paper_DS3-Interim-Tariffs-Consultation-FINAL-08042016.pdf

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

4.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

The Capacity Requirement 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 consultation took place following an initial paper in March 2006 titled 'The Capacity Payment Mechanism and Associated Input Parameters' (AIP/SEM/15/06).

A Decision Paper was published in February 2007 which set out the RAs' decisions on the contents of the August 2006 Consultation Paper. This Decision Paper described the key methodology and individual data point assumptions. These parameters were used in calculating all previous Capacity Requirements.

4.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2017

The following sections describe further each of these parameter settings used in the calculation of the 2017 Capacity Requirement.

4.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours loss of load expectation per annum. The GSS of 8 hours has been retained by RAs for the 2017 calculation.

4.3.2 DEMAND FORECAST

For the purposes of calculating the Capacity Requirement, the demand forecast was taken from the median scenario of the Eirgrid / SONI forecast in Appendix 1 of the 2016-2025 All-Island Generation Capacity Statement[8]. This forecast is stated in terms of the Total Energy Requirement (total energy exported from generating units, plus self-consumption).

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[8] The 2016-25 GCS can be found at the following link http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

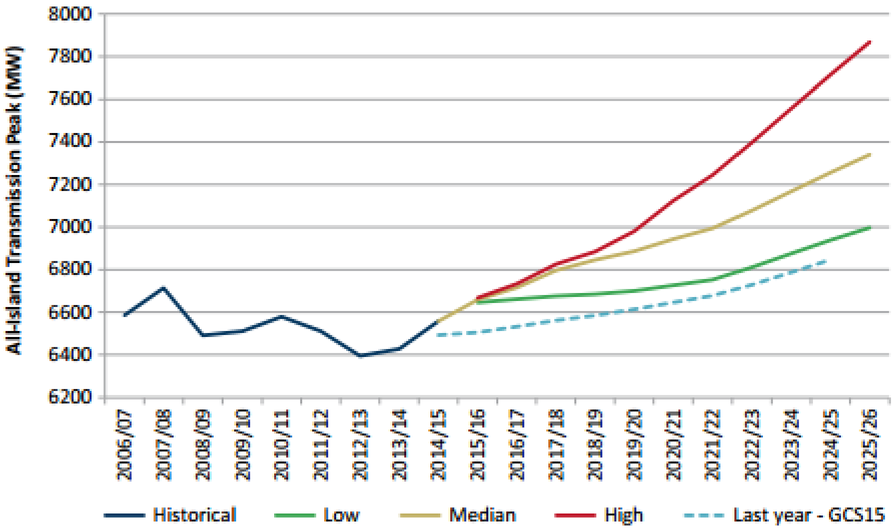

Figure 2 - All-Island Demand Forecast [9]

The Demand forecast not only takes into account economic conditions but also looks at historical annual load shape and typical weather patterns.

For the 2017 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 aligned on a day-by-day basis. The RAs assisted in combining these jurisdictional load traces into a demand trace for input to the ADCAL calculation engine (described below).

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

	2017 Forecasted Total Energy Requirement
Republic of Ireland	28,971
Northern Ireland	9,163
All-Island	38,134

Table 5 – Total Energy Requirement Forecast

While changes in total energy requirement will have an effect on the changes to the Capacity Requirement, of greater impact will be the changes in the peak demand.

[9] Chart taken from Figure 2-10 , Page 25 , All-island Generation Capacity Statement 2016-25

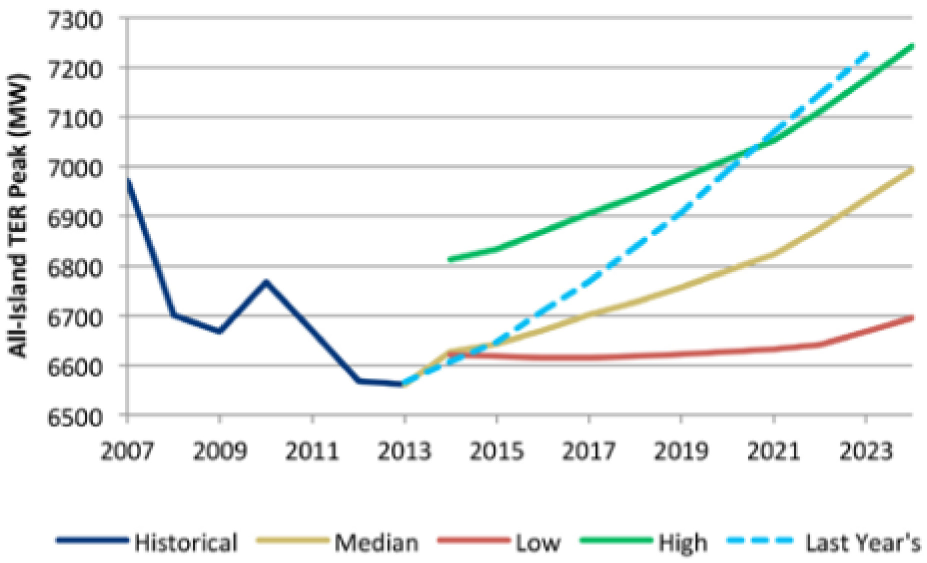

Figure 3- All-Island Peak Demand Forecast

4.3.3 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 2017 Capacity Requirement process.

4.3.4 FORCED OUTAGE PROBABILITIES

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

As described in the Decision Paper on the CPM Medium Term Review, the SEM Committee decided to amend the FOP to 5.91%, it is this figure that is used in the 2017 Calculation.

4.3.5 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explained the RAs' decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2017 process. Individual wind output traces were provided by the TSOs. The wind traces are aligned on a day-by-day basis with the load traces described earlier.

4.3.6 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2017 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 2015 that arises from the conventional market capacity, employed to meet the 2015 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.

4.4 PROPOSED CAPACITY REQUIREMENT FOR 2017

The inputs used in the 2017 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 2017	A combined load forecast for 2017, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. Two traces were agreed: 1) Total Load Forecast for 2017 2) Total (In Market) Conventional Load Forecast 2017
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 2017, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average).
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
Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the five-year average of scheduled outages for each unit.
Force Outage Probability (FOP)	In line with the SEM Committee decision on the CPM Medium Term Review, the FOP has been set at **5.91%**.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 6 – Inputs to Capacity Requirement

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2017 is **7,267 MW.** This is an increase of 197MW from the Capacity Requirement for 2016 of 7,070MW.

The Proposed Capacity Requirement for 2017 is 7,267MW

5 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2017

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement the ACPS for 2017 are detailed in the table below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2017	70.99	7267	515,884,330

Table 7 – Indicative ACPS 2017

The Proposed Annual Capacity Payments Sum (ACPS) for 2017 is €515,884,330

6 FCPPy AND ECPPy FOR 2017

6.1 INTRODUCTION

The SEM Trading and Settlement Code requires the RAs to determine on an annual basis values for certain parameters in relation to the calculation of Capacity Payments and Capacity Charges for the following year. These parameters include:

- Fixed Capacity Payments Proportion (FCPPy), such that $0 \leq \text{FCPPy} \leq 1$;
- Ex-Post Capacity Payments Proportion (ECPPy), such that $0 \leq \text{ECPPy} \leq (1\text{-FCPPy})$

The Fixed Capacity Payments Proportion (FCPPy) sets the proportion of each monthly Capacity Period Payment Sum to be allocated on a fixed basis. This is based on a demand forecast and the payments are set before the start of the year.

The Ex-Post Capacity Payment Proportion (ECPPy) sets the proportion of each monthly Capacity Period Payment Sum to be allocated according to the ex-post Loss of Load Probability (LOLP) in each Trading Period in the month. The payments are determined after the end of each month.

A third value, the Variable Capacity Payment Proportion (VCPPy) is implicitly derived from the values of FCPPy and ECPPy. This is set such that:

$$\text{VCPPy} = (1 - \text{FCPPy} - \text{ECPPy})$$

The VCPP sets the proportion of each monthly Capacity Period Payment Sum to be allocated according to the forecast LOLP for each Trading Period in the month. These payments are determined before the start of the month.

Since the start of the SEM, these parameters have been set at the following values:

$$\text{FCPPy} = 0.3$$
$$\text{ECPPy} = 0.3$$
$$\text{VCPPy} = 0.4$$

6.2 PROPOSED SETTINGS

For the Trading Year 2017 the RAs do not intend to consult on the payment proportions. The SEM Committee approved fixing these proportions in the Final Decision paper on ECPP and FCPP published in November 2015. This decision followed the consultation paper to which there were no responses from participants.

The RAs will retain the above figures for each proportion and include here for information only.

7 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 17 June 2016**.

The SEM Committee 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.

8 APPENDIX 1 - ACPS FOR PREVIOUS TRADING YEARS

The annualised fixed cost of a BNE Peaking Plant is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for all previous years are detailed in the table 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	7046	574,953,600
2016	72.82	7070	514,837,400
2017[10]	70.99	7267	515,884,330

Table A.1 – Historical ACPS values (with indicative 2017 figures)

[10] Indicative values only.

9 APPENDIX 2- 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
2015	27,425	2.4%	9,058	0.1%	36,483	1.8%	5043	1752	6746	4945	1733	6631
2016	27,989	2.1%	9,097	0.4%	37,086	1.7%	5092	1761	6805	4994	1741	6687
2017	28,899	3.3%	9,139	0.5%	38,038	2.6%	5167	1769	6888	5070	1747	6769
2018	29,566	2.3%	9,178	0.4%	38,745	1.9%	5209	1777	6938	5112	1753	6818
2019	30,159	2.0%	9,216	0.4%	39,375	1.6%	5243	1785	6980	5146	1761	6858
2020	30,681	1.7%	9,255	0.4%	39,935	1.4%	5294	1792	7038	5196	1767	6916
2021	31,238	1.8%	9,297	0.5%	40,535	1.5%	5338	1799	7089	5241	1773	6966
2022	31,788	1.8%	9,337	0.4%	41,125	1.5%	5416	1807	7174	5319	1780	7051
2023	32,365	1.8%	9,381	0.5%	41,746	1.5%	5498	1815	7264	5400	1787	7140
2024	32,934	1.8%	9,420	0.4%	42,354	1.5%	5578	1823	7354	5481	1795	7229
2025	33,480	1.7%	9,463	0.5%	42,943	1.4%	5655	1832	7439	5558	1803	7313

Table A.2: Median Demand Forecast

10 APPENDIX 3- DS3 REVENUES FOR ALSTOM GT13E2

Service Name	Abbreviation	Capability (MW)	Units of Service provided	Rates (€/MW)	Revenues (€)
Synchronus Inertial Response	SIR	2479.5	434,408	0.004	1,738
Fast Frequency Response	FFR	10.6	1,857	1.96	3,640
Primary Operating Reserve	POR	21.2	3,714	2.47	9,174
Secondary Operating Reserve	SOR	35.4	6,202	1.37	8,497
Tertiary Operating Reserve 1	TOR1	35.4	6,202	1.19	7,380
Tertiary Operating Reserve 2	TOR2	35.4	6,202	0.99	6,140
Replacement Reserve - Synchronised	RRS	195.7	34,287	0.13	4,457
Replacement Reserve - Desynchronised	RRD	195.7	1,545,813	0.64	989,320
Ramping Margin 1	RM1	78.28	13,715	0.08	1,097
		195.7	1,545,813	0.08	123,665
Ramping Margin 3	RM3	78.28	13,715	0.13	1,783
		195.7	1,545,813	0.13	200,956
Ramping Margin 8	RM8	78.28	13,715	0.1	1,371
		195.7	1,545,813	0.1	154,581
Fast Post Fault Active Power Recovery	FPFAPR	117.42	20,572	0.13	2,674
Steady State Reacctive Power	SSRP	212	37,142	0.2	7,428
Dynamic Reactive Resposne	DRR	195.7	34,287	0.03	1,029

Table A.3 – DS3 Capabilities for Alstom GT13E2