Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant

Calculation Methodology

Consultation Paper

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2 BACKGROUND

In May 2005 the Regulatory Authorities (RAs) set out the options for the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM)[1]. In the paper the RAs indicated their proposal to develop a fixed revenue capacity payment mechanism that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code (TSC).

In March 2006[2] 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 and the processes that the RAs propose for determining the annual capacity payment and the general process by which it is proposed that input parameters to the CPM would be set.

The March 2006 paper reiterated the proposed outline of the CPM for the SEM suggesting that annual capacity payments should be fixed and that the annual fixed sum be divided into a number of within-year pots, i.e. Capacity Periods. The paper also set out proposals for the determination of the Annual Capacity Payment Sum (ACPS). The paper proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator. The RAs proposed that, for the purposes of determining the ACPS, the cost of new entrant generation should be assessed in terms of a 'Best New Entrant' (BNE) peaking plant. The cost of the BNE peaking plant calculated would be expressed in €/kW per year (as an annualised payment) and multiplied by the capacity requirement to calculate the ACPS.

The criteria, which have formed the basis of the Regulatory Authorities' decision making process in relation to the CPM, are outlined below.

1) **Capacity Adequacy/ Reliability of the system**
   The CPM must encourage both the construction and maintained availability of capacity in the SEM. Security of the system, will be the core feature of the CPM.

2) **Price Stability**
   The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market

3) **Simplicity**
   The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism could reduce investor confidence in the market and increase implementation costs.

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

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

4) **Efficient price signals for Long Term Investments**

In theory it would be possible to incentivise vast amounts of capacity over and above that necessary for system security in the SEM, although the cost of implementing such a scheme may be unacceptable to customers. The CPM should meet the criterion in this section at the lowest reasonable cost. Revenues earned by generators should still efficiently signal appropriate market entry and exit.

5) **Susceptibility to Gaming**

The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties.

6) **Fairness**

The CPM should not unfairly discriminate between participants. An appropriate CPM will maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

On 11th September 2008, the Single Electricity Market Committee (SEMC) published its Decision Paper regarding the Fixed Cost of a Best New Entrant Peaking Plant for the calendar year 2009[3] (SEM-08-109). In this decision paper, the SEMC signalled its intention to consult on the appropriate mechanism to address a key concern raised by industry participants regarding the stability of the capacity payment pot due to the annual determination of the Best New Entrant Fixed Cost (BNEFC) and the Annual Capacity Payment Sum (ACPS). This consultation paper addresses this area.

[3] http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=48679b7e-aa47-49bf-9a82-1c8e4c863014

3 PREVIOUS BNE CALCULATIONS

As part of the Regulatory Authorities' (RAs) agreed duties in the administration of the Capacity Payments Mechanism of the SEM, there have to date been three iterations of calculations by the RAs for the Fixed Costs of a Best New Entrant Peaking Plant. The three iterations have been conducted for the Trading Years 2007, 2008 and 2009. These are summarised below.

3.1 2007 BNE CALCULATION

On 13 February 2007 the RAs published a Consultation Paper entitled 'Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism; Decision and Further consultation Paper' (SEM-07-014). A subsequent Decision Paper (SEM-07-187), stipulating the final Best New Entrant Fixed Costs for 2007 was published on 18th May 2007.

The plant chosen for the BNE for 2007 was:

- Alstom 13E2 Gas Turbine
- Distillate-fired
- Located in the Republic of Ireland (RoI)
- Annualised fixed cost of €85.04/kW/yr
- Estimated Infra-marginal Rent of €14.19/kW/yr
- Estimated Ancillary Service Revenue of €6.12/kW/yr
- Adjusted annualised fixed cost of **€64.73/kW/yr**

3.2 2008 BNE CALCULATION

The BNE Fixed Costs for 2008 were worked out based upon the settings for 2007, with indexing applied to certain parameters. This is described in the paper 'Annual Capacity Payment Sum – Final Value for 2008' (AIP-SEM-07-458).

- Estimated Infra-marginal Rent of €0.00/kW/yr
- Estimated Ancillary Service Revenue of €6.18/kW/yr
- Adjusted annualised fixed cost of **€79.77/kW/yr**

3.3 2009 BNE CALCULATION

On 4th July 2008 the SEM Committee (SEMC) published a Consultation Paper entitled 'Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009' (SEM-08-083). A subsequent Decision Paper (SEM-08-109), stipulating the final Best New Entrant Fixed Costs and Capacity Requirement for 2009 was published on 11th September 2008.

The plant chosen for the BNE for 2009 was:

- Siemens SGT5 2000E Gas Turbine
- Distillate-fired
- Located in the Republic of Ireland (RoI)
- Annualised fixed cost of €93.81/kW/yr
- Estimated Infra-marginal Rent of €0.00/kW/yr
- Estimated Ancillary Service Revenue of €6.69/kW/yr
- Adjusted annualised fixed cost of **€87.12/kW/yr**

4 OBJECTIVES OF PAPER

The SEMC is of the view that the CPM an integral part of the SEM design and should be kept as a feature of the SEM. In this regard the SEMC agree that capacity payments in the SEM perform two main roles. One is that they provide revenues to cover the capital and fixed costs which are not covered in the SEM by payments for energy. This applies for both potential new investors and for any existing plant. The other is that the capacity payments provide incentives for generators to be available at times when the system needs generation capacity.

The SEMC is also of the view that at this early stage of the SEM it may not be appropriate to significantly change or alter the design, calculation, or operation of the Capacity Payment Mechanism, particularly as there is no evidence to strongly suggest that a significant change in the design and the calculation of the BNEFC and ACPS is required at this juncture.

Notwithstanding the above, the SEMC consider that some aspects of the CPM merits review in the short to medium term to ensure that the original objectives of the SEM will continue to be met. The SEMC has decided that a review of these particular aspects of the CPM should be conducted, in two phases.

The first phase focusing on the possibility of reducing volatility in the capacity payments pot and looking at the possibility of setting the best new entrant fixed cost (BNE) for a period longer than one year.

The second phase (planned to start in Q3/2009) will concentrate on a wider range of issues, such as the way in which the monies available from the CPM are calculated and the manner in which they are distributed. It is expected that the second phase will cover areas such as:

- Assessment of CPM in SEM (historical analysis)
- Impact of CPM on Customers
- Incentives for Generators
- Capacity Payments when Capacity is needed
- Distribution of Capacity Payments
- Capacity Requirement Calculation
- WACC Methodology
- Infra Marginal Rent & CPM
- Treatment of Wind in CPM
- Treatment of Interconnector in CPM
- Relationship of CPM with Ancillary Services
- Impact on Diversity of Generation & Security of Supply

In this regard the SEMC is cognisant that the scope of the first phase is limited to reducing the year on year variability in the revenues received by generators from the CPM without changing the intrinsic uncertainty in the future evolution of the BNEFC.

The SEMC is minded to balance the objectives of the CPM and the overarching objectives of the SEM, which includes customer protection. In recognition of this the RAs proposals have made reference to the overall objectives of the CPM and principles such as simplicity, fairness and efficient price signals and will seek to balance these with principles such as cost reflectivity and effects on customers.

For convenience in this paper, the annualised fixed cost of the Best New Entrant peaking plant that is used to generate the Annual Capacity Payments Sum (ACPS) for a given Trading Year will be referred to as the BNEFC for that Trading Year. This parameter does not refer to the output of a given exercise (necessarily), but to the actual value that is published and used, along with the Capacity Requirement, to generate the ACPS.

5 DETERMINATION OF BNEFC – CURRENT APPROACH

While not the focus of this paper, it is worth noting the challenge the RAs face in carrying out the BNEFC exercise each year. That is, the challenge of simulating the role of a rational investor proceeding to the commissioning of a multi-million-euro power project. The RAs engage the expertise of consultants to carry out the assessments and advise them on the likely cost a rational investor would face to procure and construct a peaking plant in the SEM. The consultants carry out a robust assessment to provide their advice, but there are many subjective questions raised as part of the process of simulating the role of an investor that can lead to potential volatility in the year-by-year BNEFCs.

One option is to diversify the estimation of parameters that are sensitive to these effects by contracting multiple consultants, to the extent possible, to provide independent unbiased estimates on those line items (most notably the EPC parameters). Another option is to include the use of a standard database or software tool that is commonly used by generation companies in the process.

This is a measure that the RAs would welcome comment on but is something that is considered a 'minded to' approach going forward.

Consultation Point 1:

The RAs welcome comments from participants in relation to approaches that would significantly improve the method used by the RAs of determining the BNE costs, without imposing considerable costs to customers.

6 OPTIONS TO REDUCE THE PERCEIVED VOLATILITY OF BNEFC

The RAs have considered the options available that may be used to reduce the perceived volatility in the BNEFC. These are summarised below and then each option is discussed in more detail later in the document.

Option 1 – Calculate BNEFC on an annual basis with all components recalculated annually.

Use the current methodology to calculate the BNEFC with every constituent element of the calculations variable re-visited each year.

Option 2 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years

Use the current methodology to calculate the BNEFC but with some constituent elements kept unchanged for a period of, 3 or 5 years for example. These elements would include both choice variables, such as the technology of the peaker, the choice of fuel, the siting of the plant, the capacity of the plant, the environmental standards to be met, etc; as well as cost/revenue variables. In principle, the fewer the variables that have to be re-estimated each year, the more stable the BNE cost will be, at least over the 3 or 5 year period.

Option 3 - Calculate BNEFC on an annual basis with all components recalculated annually. Smoothing is then applied.

Use the current methodology to calculate the BNEFC, as defined in Option 1 but put less weight on the current in-year estimate by including previous BNEFC to derive a simple or a weighted arithmetic average.

Option 4 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years. Smoothing is then applied.

Use the current methodology to calculate the BNEFC, as defined in Option 2 but put less weight on the current in-year estimate by including previous BNEFC to derive a simple or a weighted arithmetic average.

Option 5 – Calculate the BNEFC and keep it in place for a multiple year period.

Make estimates only every 3 or 5 years for the BNEFC either of all the variables or of a subset and index the cost in the intervening years.

Option 6 – Fixed price for new entrants

An option that was suggested in the responses to the Consultation Paper for the Fixed Cost of a Best New Entrant Peaking Plant for the calendar year 2009 was to have a separate mechanism for new entrants.

Consultation Point 2:

The RAs welcome comments from participants on whether there are other options that should be considered in order to reduce the volatility of the BNEFC.

6.1 OPTION 1 – CALCULATE BNEFC WITH ALL COMPONENTS RECALCULATED ANNUALLY

The current method of calculation of the BNE is an annual activity that involves building up the various costs based on the latest prices. The main areas of costs are described below.

6.1.1 CAPITAL COSTS

The Capital Cost items of the BNE are dictated by several parameters, the most onerous of which is the Engineering, Procurement and Construction (EPC) Cost. This cost itself is made up of several components which must be assessed to a high degree of rigour.

The cost of Engineering, Procurement and Construction is known to operate in a broadly cyclical pattern and has risen sharply over the past few years in response to high global demand. Though this has resulted in increasing costs (this is indeed reflected in the upward trend since 2007 of the BNE calculation), of more pressing concern is the notion that the market for turbines is not highly liquid. This combination creates the potential for the Capex estimate for a new entrant peaking plant to vary significantly from one year to the next and also to vary within-year by material margins. The RAs note that investors are faced with the challenge of managing this type of volatility but this is one that would still exist in the absence of a CPM.

In addition, the choice of technology depends on a wide array of factors, because 'candidate' plants are (presently) evaluated from a pool developed by the RAs expert advisors using a holistic approach as described in the 2009 BNE Consultation Paper (SEM-08-083). Certain technologies may have greater exposure to the price of certain commodities, and are more sensitive to demand bottlenecks in manufacturing (plant with longer build-times for example).

As global demand for gas turbines and the materials used to construct them fluctuates, with influence especially in recent years from China and India, the cost of procuring such a turbine and installing it on the island of Ireland become correspondingly exposed to this fluctuation. In addition, the global recession will also impact future prices and demands for materials.

6.1.2 RECURRING COSTS

The recurring cost items such as the Long Term Service Agreement (LTSA), Insurance and Rates are material contributors to the overall annualised fixed costs of the plant.

To the extent that 'turmoil' on financial markets impacts the affordable provision of Insurance and the cost of the LTSA, there could be argued to be some exposure to volatility in the BNEFC, but this is thought to be small compared to the other areas already mentioned.

6.1.3 WACC

Calendar 2008 has seen volatile settings for debt intra-year and the potential volatility of parameters such as the Debt Spread, Equity-Risk Premium and Inflation is generally considered material, given the significant impact that WACC settings have on the annualized fixed costs of the BNE Peaker.

The WACC parameters are key to the establishment of the final annualised cost. Line items such as Gearing, Equity Risk Premium, and Beta under the CAPM framework can materially dictate the outcome.

6.1.4 INFRA-MARGINAL RENT & ANCILLARY SERVICE REVENUE

There is recognised volatility caused by the annual effect of deducting the estimated infra-marginal rent from the annualised total. It is the view of the RAS that this is caused chiefly by the granularity of the plant mix in the SEM and poor availability of existing plant, which can tend to result in step changes to market outcomes when a new plant is commissioned.

6.1.5 SUMMARY OF OPTION 1

By employing calculations annually, the parameter in question is much more likely to track the true behaviour of the underlying costs of the economic drivers underpinning the value of that parameter. This is generally thought to be economically efficient to the extent that the cost of capital for new entrant generation is not adversely affected by having the RAs employ such a methodology. To elaborate, by re-calculating the parameters frequently, the BNEFC is ultimately not exposed to lags when the underlying economic drivers change rapidly. So during periods of volatility, sharp drops in the cost of procuring a gas turbine for example can be quickly passed on to suppliers and ultimately customers. Likewise, sharp increases in these costs can be quickly reflected in Generator payments and 'shown' to potential investors.

Another key benefit of employing more frequent calculations is that exposure to the potential for significant change in the BNE input costs from one year to the next would be minimised. Equally, effects that may emerge as a result of the sample size used by the RAs' and their consultants would also be minimised. To explain by example, if a subjective valuation for procurement of the plant (say for Contingency Cost) is made that undervalues that parameter by 20%, the impact of that inaccuracy is only carried as far as the next calculation, at which point the Contingency will be re-evaluated. The scenario of having infrequent re-evaluations of the Contingency would cause that inaccuracy to persist.

The RAs strive to achieve the most accurate estimate of the BNEFC. However, it is recognised that the commodity prices and demand for raw materials will fluctuate and this will have a knock on effect on the determined cost of the BNE Peaker and for that reason, the volatility will remain in the calculations.

Consultation Point 3:

The RAs welcome comments from participants on the materiality of any adverse effects of the current method of calculation.

6.1.6 WORKED EXAMPLE FOR OPTION 1

The worked example below shows the costs of the BNE over the next 5 years. Note that all figures used below are fictitious and for demonstration purposes only. This can be used for comparison purposes against the later options in this paper

Worked Example for Option 1	Component Period	2009 BNE	2010 BNE	2011 BNE	2012 BNE	2013 BNE
Site Procurement	1 Year	3,801	4,012	4,222	4,121	4,331
Pre Financial Close Costs						
Owner's manpower costs up to contract award	1 Year	1,054	1,145	1,293	1,300	1,410
Financial, legal costs, engineering, consultancy and EIA	1 Year	1,405	1,522	1,822	2,000	2,100
Total Pre-Financial Close Costs		2,459	2,667	3,115	3,300	3,510
Post Financial Close Costs						
E.P.C. Contract (including contingency)	1 Year	70,247	68,343	73,343	80,302	82,322
Electrical Interconnection	1 Year	6,254	6,833	7,022	7,212	7,422
Distillate Facilities	1 Year	1,069	1,222	1,322	1,403	1,592
Water Injection (NOx reduction)	1 Year	2,596	2,712	2,933	3,102	3,322
E.P.C Total		80,166	79,110	84,620	92,019	94,658
Other Costs						
Owners manpower during construction	1 Year	1,405	1,533	1,622	1,824	1,801
Taxes, insurance during construction	1 Year	352	363	389	401	422
Purchased electricity, fuel during construction	1 Year	352	382	423	456	502
T&SC Fees	1 Year	7	7	7	7	7
Contingencies	1 Year	1,202	1,100	1,298	1,360	1,488
Interest during construction	1 Year	3,462	3,322	3,298	3,311	3,401
Total Other costs		6,780	6,707	7,037	7,359	7,621
TOTAL INVESTMENT COST		93,206	92,496	98,994	106,799	110,120
Capital Cost						
Capex (Base)		93,206	92,496	98,994	106,799	110,120
Plant life		15	15	15	15	15
WACC	1 Year	7.07%	8.04%	7.54%	6.93%	6.22%
Fixed Costs						
Operations and Maintenance	1 Year	1,176	1,088	992	1,002	1,102
Transmission and SEMO charges	1 Year	935	964	1033	1503	1211
Insurance and Miscellaneous cost	1 Year	1,008	1,122	1,200	1,311	1,100
Rates cost	1 Year	1,315	1,393	1,403	1,502	1,532
Fuel Storage	1 Year	164	203	300	298	280
Total Fixed Costs		4,598	4,770	4,928	5,616	5,225
Annualised Capital plus Fixed Costs		93.81	98.38	101.96	109.02	105.47
Energy Market Infra Marginal Rent	1 Year	-0.0007	-0.0007	-1.03	0.202	-0.0007
Ancillary Service Revenue	1 Year	6.69	7.12	7.21	6.93	7.32
Annual BNE Cost		87.11	91.26	93.72	102.29	98.15
Indexation		0%	1%	3%	3%	2%
Final BNE Cost		87.11	92.17	96.54	105.36	100.11

Table 1: Costs on BNE Peaker – Worked Example for Option 1

6.2 OPTION 2 - CALCULATE BNEFC ANNUALLY WITH SOME COMPONENTS COSTS CONSTANT FOR A NUMBER OF YEARS

This option proposes the use of the current methodology to calculate the BNEFC but with some constituent elements kept unchanged for a period of, 3 or 5 years for example. The period that each element remains unchanged may vary depending on the stability of prices of that element. These elements would include both choice variables, such as the technology of the peaker, the choice of fuel, the siting of the plant, the capacity of the plant, the environmental standards to be met, etc; as well as cost/revenue variables. This is demonstrated below in a worked example.

Consultation Point 4:

Taking the worked example and indexing options into account (see below), the RAs welcome comments from participants on the proposed method for Option 2 including any additional options that may help to reduce the perceived volatility.

6.2.1 WORKED EXAMPLE FOR OPTION 2

The worked example below shows the costs of the BNE over the next 5 years. Note that all figures used below are fictitious and for demonstration purposes only. In addition, no decisions have been made in relation to the 'Component Period' column below. The periods used in the worked example are again for demonstration purposes.

Worked Example for Option 2	Component Period	2009 BNE	2010 BNE	2011 BNE	2012 BNE	2013 BNE
Site Procurement	5 Years	**3,801**	**3,801**	**3,801**	**3,801**	**3,801**
Pre Financial Close Costs						
Owner's manpower costs up to contract award	3 Years	1,054	1,054	1,054	1,300	1,300
Financial, legal costs, engineering, consultancy and EIA	3 Years	1,405	1,405	1,405	2,000	2,000
Total Pre-Financial Close Costs		**2,459**	**2,459**	**2,459**	**3,300**	**3,300**
Post Financial Close Costs						
E.P.C. Contract (including contingency)	3 Years	70,247	70,247	70,247	80,302	80,302
Electrical Interconnection	3 Years	6,254	6,254	6,254	7,212	7,212
Distillate Facilities	3 Years	1,069	1,069	1,069	1,403	1,403
Water Injection (NOx reduction)	3 Years	2,596	2,596	2,596	3,102	3,102
E.P.C Total		**80,166**	**80,166**	**80,166**	**92,019**	**92,019**
Other Costs						
Owners manpower during construction	2 Years	1,405	1,405	1,622	1,622	1,801
Taxes, insurance during construction	3 Years	352	352	352	401	352
Purchased electricity, fuel during construction	2 Years	352	352	423	423	502
T&SC Fees	3 Years	7	7	7	7	7
Contingencies	3 Years	1,202	1,202	1,202	1,360	1,360
Interest during construction	3 Years	3,462	3,462	3,462	3,311	3,311
Total Other costs		**6,780**	**6,780**	**7,068**	**7,124**	**7,333**
TOTAL INVESTMENT COST		**93,206**	**93,206**	**93,494**	**106,244**	**106,453**
Capital Cost						
Capex (Base)		93,206	93,206	93,494	106,244	106,453
Plant life		15	15	15	15	15
WACC	1 Year	7.07%	8.04%	7.54%	6.93%	6.22%
Fixed Costs						
Operations and Maintenance	2 Years	1,176	1,176	992	992	1,102
Transmission and SEMO charges	2 Years	935	935	1033	1033	1211
Insurance and Miscellaneous cost	2 Years	1,008	1,008	1,200	1,200	1,100
Rates cost	2 Years	1,315	1,315	1,403	1,403	1,532
Fuel Storage	2 Years	164	164	300	300	280
Total Fixed Costs		**4,598**	**4,598**	**4,928**	**4,928**	**5,225**
Annualised Capital plus Fixed Costs		**93.81**	**97.82**	**98.03**	**104.30**	**103.06**
Energy Market Infra Marginal Rent	1 Year	-0.0007	-0.0007	-1.03	0.202	-0.0007
Ancillary Service Revenue	1 Year	6.69	7.12	7.21	6.93	7.32
Annual BNE Cost		**87.11**	**90.70**	**89.79**	**97.57**	**95.73**
Indexation		0%	1%	3%	3%	2%
Final BNE Cost		**87.11**	**91.61**	**92.48**	**100.50**	**97.65**

Table 2: Costs on BNE Peaker – Worked Example for Option 2

6.2.2 INDEXING METHODS

Should a decision be made to employ a frequency of calculation for any parameter less than the current arrangement (i.e. annually), a need will arise to facilitate appropriate Indexing to account for the time-dependent value of money.

To continue with the worked example used above, if the cost of a transformer was to be only recalculated once every three years, it would be necessary to adjust the transformer's cost for the two years following the calculation.

The usual approach for regulatory exercises is to employ some form of the appropriate Retail Price Index (RPI). The Consumer Price Index – which strips out mortgage interest and council tax, focusing on a narrower basket of goods and services than RPI, may also be relevant.

In previous exercises such as for quantification of VOLL in the SEM, the RAs have employed the Irish Harmonised Index of Consumer Prices (HICP) (using a weight of two-thirds) and the UK HICP (using a weight of one third). This is suggested as a base from which to apply indexing for the BNE.

It is worth noting that there exist more sophisticated indices which may better reflect year-on-year changes in the cost of procuring generation technology and services. For example, IHS CERA produce a Power Capital Costs Index periodically that is designed to capture the movements relevant for power procurers in North America[4]:

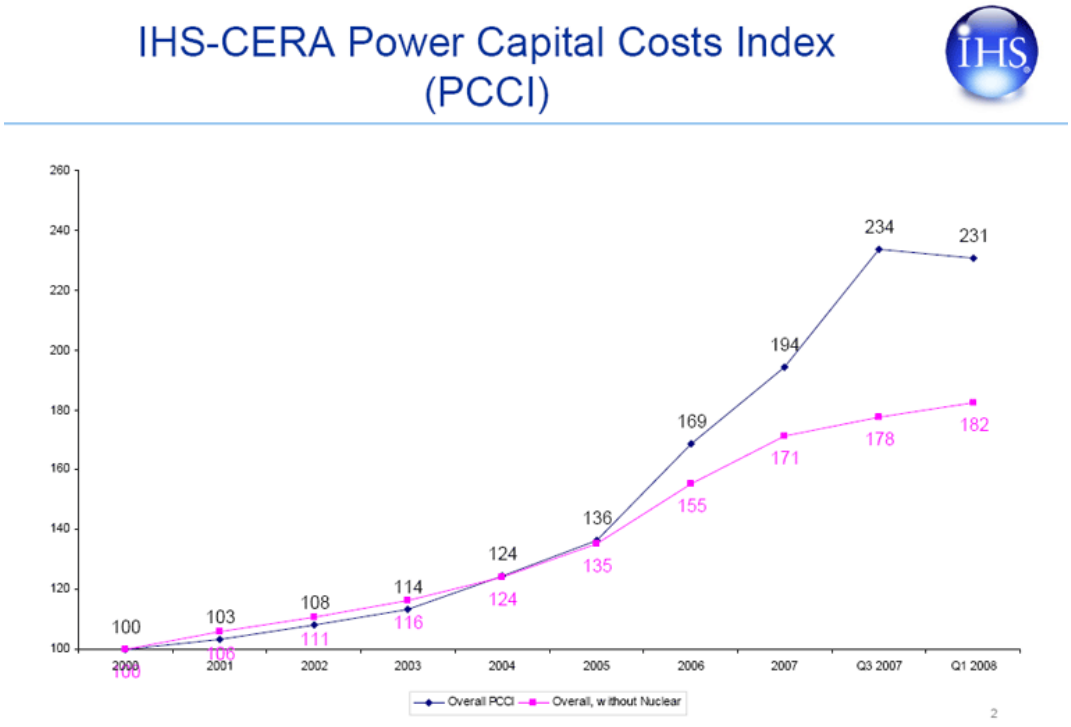

Figure 1: PCCI by IHS - CERA

[4] Provided courtesy of IHS CERA

There are complications with employing such an index for a regulatory exercise as onerous as the BNE, for example the fact that the index is produced by a commercial enterprise. The use of such indices would require the discretion of the RAs and the feeling amongst participants may be that this discretion would only worsen regulatory uncertainty without improving the perceived stability of the mechanism.

Consultation Point 5:

The RAs have detailed four indexing options above:

- **RPI**
- **CPI**
- **HICP**
- **PCCI**

The RAs welcome views on which of the above would be the most appropriate method of indexing. In addition, the RAs welcome suggestions from participants on other indexing options.

6.3 OPTION 3 - CALCULATE BNEFC ANNUALLY AND APPLY SMOOTHING EFFECT

This option builds on the methodology of Option 1, but adds one additional task to the end of the calculation. In option 3, the full BNEFC is calculated each year. However, the actual value of the BNEFC that is used in the ACPS takes account of the BNEFC calculations from the previous years. The costs are smoothed using a simple or a weighted arithmetic average. This will help reduce the volatility in the calculations.

The concept of smoothing relates to the notion that the BNEFC could be built partly using data from previous exercises so as to mitigate the impact of sharp increases and decreases in the underlying driving factors year-on-year. In other words, suppose a decision was made to implement Option 3 to calculate the cost of the BNEFC by taking a rolling un-weighted average over three years, starting only from the 2010 BNEFC. This can be represented on the Calculation Map:

ACPS for Trading Year	**2009**	**2010**	**2011**	**2012**
BNEFC				

Figure 2: Calculation Map with Smoothing

In the figure, the 2010 BNEFC is calculated as the un-weighted average of the 2008 (black star), 2009 (green star) and 2010 (blue star) BNE exercises (recall the 2010 exercise actually takes place during Calendar 2009). The pattern is then rolled forward as the 2011 cost is a function of 2009, 2010 and 2011, but ignores 2008.

The concept of weighting of previous data presents an interesting question. In the example above, the three previous years contribute on an equal weighting to the BNEFC but there is an opportunity to tune this such that:

$$\text{Smoothed BNEFC}_{y} = \alpha \times \text{BNEFC}_{y} + \beta \times \text{BNFEC}_{y-1} + \gamma \times \text{BNEFC}_{y-2} \quad \ldots$$

Where Smoothed BNEFCy is the actual transformer cost that is used to calculate the ACPS, BNEFC_{y} is the cost of the BNE exercise performed for year y, and alpha, beta and gamma are numbers between zero and one that sum to unity.

To elaborate on the previous example numerically, the BNE exercise for 2009 established a cost of close to €87.11/kW/yr. Now suppose, assuming all else equal (including not least the technology choice) that the BNEFC is re-costed for the 2010 exercise at €91.61/kW/yr and for the 2011 exercise at €92.48/kW/yr.

Using the map shown in Figure 2 and assuming equal weightings (alpha, beta and gamma all equal to 1/3), the BNEFC for 2011, i.e. the *actual* value used to scale up the Capacity Requirement into the ACPS would be derived from:

$$\text{Smoothed BNEFC}_{2011} = \alpha \times \text{BNEFC}_{2011} + \beta \times \text{BNEFC}_{2010} + \gamma \times \text{BNEFC}_{2009}$$

so

$$\text{BNEFC}_{2011} = \frac{1}{3} \times €92.48 + \frac{1}{3} \times €91.61 + \frac{1}{3} \times €87.12 = €90.40$$

Consultation Point 6:

The RAs welcome views on the following:

1) **Is smoothing as described above a suitable tool to reduce the perceived stability of the BNEFC**
2) **If so, other what timeframe should the smoothing occur?**
3) **Should a simple or weighted arithmetic average be considered?**
4) **If a weighted average is to be used, what values should be used for each of the weights?**

6.3.1 TRANSITION FROM 2007, 2008 AND 2009

As well as considering the frequency of calculation and the options for smoothing as detailed above, the RAs also deem it prudent to raise the option of when the frequency and smoothing should apply and whether the work on the CPM completed in preparation for and since SEM Go Live should be considered.

There are two options in this regard:

- **Option A** – Apply the smoothing on a forward basis, i.e. implement smoothing following the calculation of the 2010 BNEFC
- **Option B** – Include the impact of the BNEFC Calculations from 2007, 2008 and 2009 in the smoothing calculations.

Option B is discussed below where the potential cost to consumers as a result of smoothing is highlighted.

There will be a transient effect in implementing changes to the derivation of the BNEFC because of the fact that the ACPS for 2007, 2008 and 2009 have not been calculated using the new method. Of particular concern to the RAs is the notion that the cost of procuring a gas turbine, which is known to operate as a cyclical cost over time, may in recent years have been increasing to a peak. This is the indication that the RAS have received from their various independent consultants, including from the first work performed for the 2007 BNEFC. Indeed the increasing BNEFC's determined so far provide some measure of this effect.

The problem with implementing a change to the frequency or smoothing settings for the BNEFC is that Generators may materially have gained by the change having happened particularly in 2009/10, while consumers may materially have lost. The reverse is also true. If 2009/10 had happened to coincide with a 'trough', the reverse would be the case in that the introduction of a smoothing process in 2009 would inhibit the ability for Generators to see a reflective short-term increase in the BNEFC, but without the counter-measure of the protection that the smoothing would have offered them in the years prior to the trough (as the smoothing was not in place during those years).

To show by illustration, Figure 3 depicts the application of a 50 / 50 two-year smoothing lag applied to the overall BNE cost from 2010, and a situation whereupon the spot BNE estimates began to decline from 2010 onward:

Worked Example for Option 3	2007 BNE	2008 BNE	2009 BNE	2010 BNE	2011 BNE	2012 BNE	2013 BNE	2014 BNE
BNEFC	64.73	79.77	87.12	80.42	75.61	74.21	72.56	70.12
50% of Y-1	-	-	-	43.56	40.21	37.81	37.11	36.28
50% of Y	-	-	-	40.21	37.81	37.11	36.28	35.06
2 Year smoothing applied	64.73	79.77	87.12	83.77	78.02	74.91	73.39	71.34

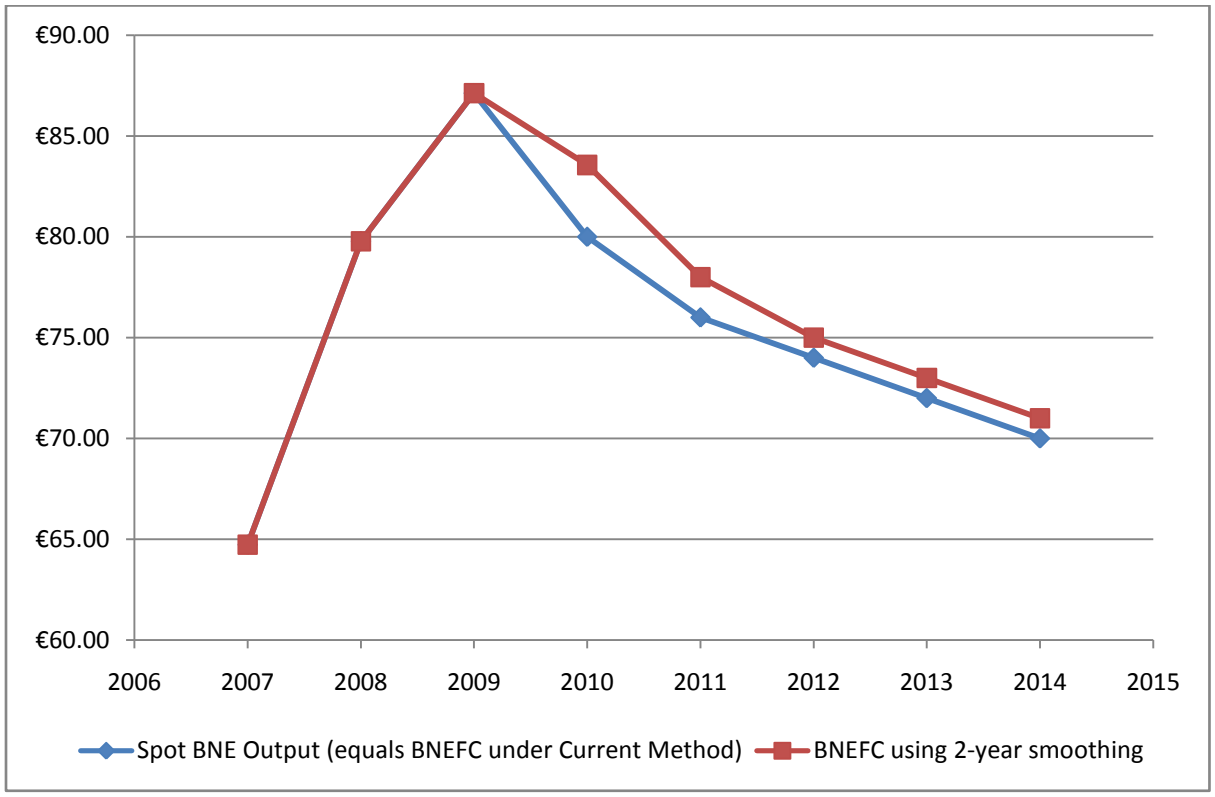

Figure 3: Example of potential impact of Decision on ACPS - 1

In Figure 3, a decrease in the spot BNE estimates has been plotted to show the impact that the introduction of a smoothing lag would have on consumers. Critically, the gap between the red and blue lines is not, in the figure, compensated for by a historic smoothing that would have prevented the 2009 peak from being passed through to the 2009 ACPS. Had the RAs established the said smoothing as at Go-Live in 2007, the picture would have (applying the consistent 2 year smoothing) appeared as depicted in Figure 4.

Worked Example for Option 3	2007 BNE	2008 BNE	2009 BNE	2010 BNE	2011 BNE	2012 BNE	2013 BNE	2014 BNE
BNEFC	64.73	79.77	87.12	80.42	75.61	74.21	72.56	70.12
50% of Y-1	-	32.37	39.89	43.56	40.21	37.81	37.11	36.28
50% of Y	-	39.89	43.56	40.21	37.81	37.11	36.28	35.06
2 Year smoothing applied	64.73	72.25	83.45	83.77	78.02	74.91	73.39	71.34

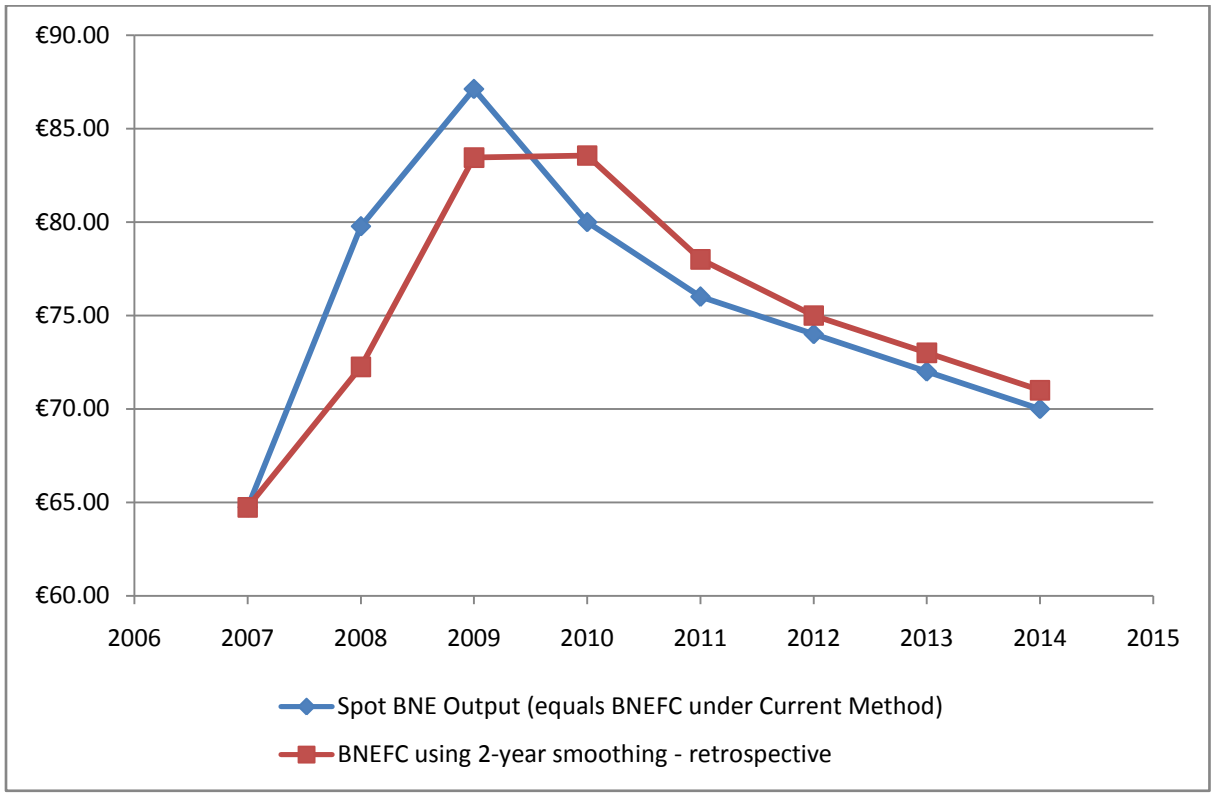

Figure 4: Example of potential impact of Decision on ACPS - 2

The comparison here is clear; namely that the benefits of the smoothing were not applied during the increasing period and the ACPS's published in 2008 and 2009 would have been materially lower had the smoothing method been in place prior to Go-Live.

Therefore under option B it is proposed that a 'Legacy' measure is introduced for coping with this. Essentially, the measure will quantify an amount by which the BNEFC in 2007, 2008 and 2009 'would have moved' should the new method have been in place at the time the BNEFC's were calculated.

The Legacy effect could be spread over several Trading Years. Alternatively, all legacy adjustments for the existing published BNEFC's could simply be applied (netted) to the 2010 BNEFC. Figure 5 shows how the legacy effect could be applied. Note that indexing has not been included below but would be considered if this option was to be implemented.

Legacy Options	2007	2008	2009	2010	2011	2012	2013	2014
BNEFC	64.73	79.77	87.12	80.42	75.61	74.21	72.56	70.12
2 Year smoothing applied	64.73	72.25	83.45	83.77	78.02	74.91	73.39	71.34
BNE Variance due to smoothing	0.00	7.52	3.68	-	-	-	-	-
2 Year smoothing applied with legacy effect applied in 2010	64.73	72.25	83.45	72.58	78.02	74.91	73.39	71.34
2 Year smoothing applied with legacy effect applied over 3 years	64.73	72.25	83.45	80.04	74.28	71.18	73.39	71.34

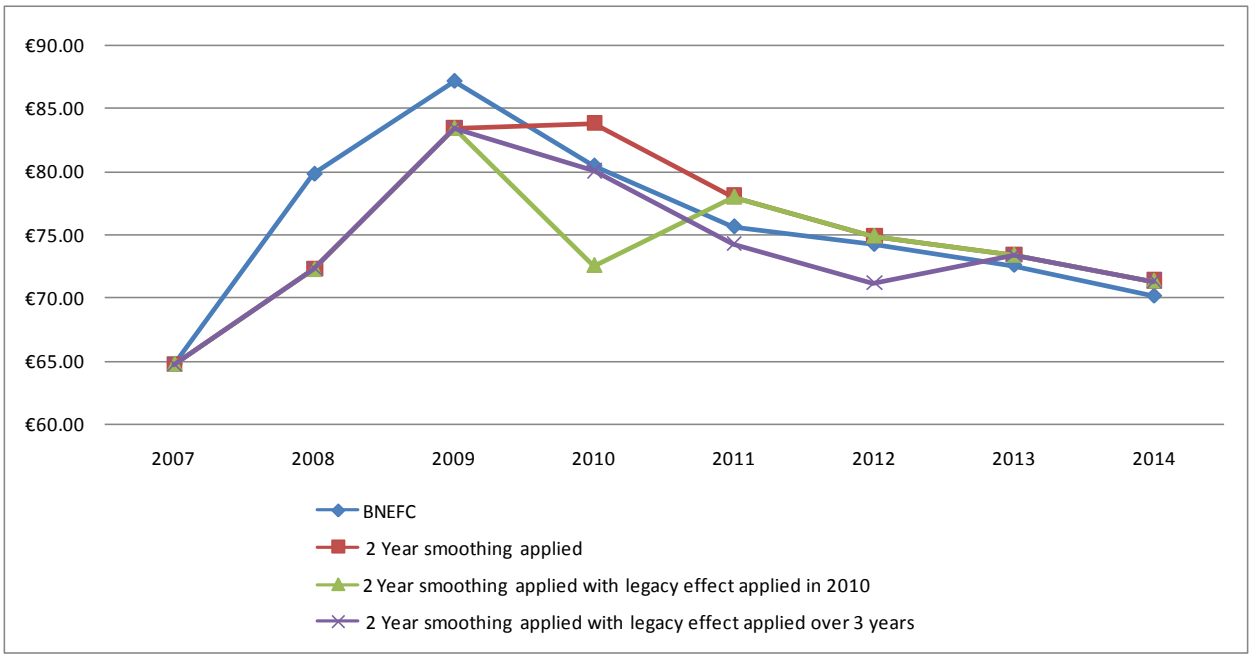

Figure 5: Example of potential impact of Legacy Options on ACPS

Consultation Point 7:

The RAs welcome comments from participants on the proposed 'Legacy' measure and the options for implementing this.

6.4 OPTION 4 - CALCULATE BNEFC ANNUALLY WITH SOME COMPONENT COST CONSTANT FOR A NUMBER OF YEARS AND APPLY SMOOTHING EFFECT

Option 4 builds on the method defined in Option 2, but adds one additional task to the end of the calculation. For each of the components in Option 2, depending on the frequency of calculation, the costs will be smoothed between years using a method similar to that described in Section 6.3. The costs are smoothed using a simple or a weighted arithmetic average. This will help reduce the volatility in the calculations.

It should be noted that the issues relating to indexing, frequency of calculation and type of smoothing discussed above are applicable to this option

In order to demonstrate how this option could work, the worked example used in section 6.4.1 is expanded below.

Consultation Point 8:

The RAs welcome comments from participants on the proposed Option 4 and the merits of this implementation.

6.4.1 WORKED EXAMPLE FOR OPTION 4

This example uses the same figures as used in Option 2 above. In this example smoothing as been applied based on the following breakdown 50% x (Y) + 30% x (Y-1) + 20% x (Y-2)

Worked Example for Option 4	Component Period	2009 BNE	2010 BNE	2011 BNE Smoothed	2012 BNE Smoothed	2013 BNE Smoothed
Site Procurement	5 Years	**3,801**	**3,801**	**3,801**	**3,801**	**3,801**
Pre Financial Close Costs						
Owner's manpower costs up to contract award	3 Years	1,054	1,054	1,054	1,177	1,251
Financial, legal costs, engineering, consultancy and EIA	3 Years	1,405	1,405	1,405	1,703	1,881
Total Pre-Financial Close Costs		**2,459**	**2,459**	**2,459**	**2,880**	**3,132**
Post Financial Close Costs						
E.P.C. Contract (including contingency)	3 Years	70,247	70,247	70,247	75,274	78,291
Electrical Interconnection	3 Years	6,254	6,254	6,254	6,733	7,020
Distillate Facilities	3 Years	1,069	1,069	1,069	1,236	1,336
Water Injection (NOx reduction)	3 Years	2,596	2,596	2,596	2,849	3,001
E.P.C Total		**80,166**	**80,166**	**80,166**	**86,092**	**89,648**
Other Costs						
Owners manpower during construction	2 Years	1,405	1,405	1,514	1,579	1,712
Taxes, insurance during construction	3 Years	352	352	352	376	366
Purchased electricity, fuel during construction	2 Years	352	352	387	409	463
T&SC Fees	3 Years	7	7	7	7	7
Contingencies	3 Years	1,202	1,202	1,202	1,281	1,328
Interest during construction	3 Years	3,462	3,462	3,462	3,387	3,341
Total Other costs		**6,780**	**6,780**	**6,924**	**7,039**	**7,217**
TOTAL INVESTMENT COST		**93,206**	**93,206**	**93,350**	**99,811**	**103,798**
Capital Cost						
Capex (Base)		93,206	93,206	93,350	99,811	103,798
Plant life		15	15	15	15	15
WACC	1 Year	7.07%	8.04%	7.54%	6.93%	6.22%
Fixed Costs						
Operations and Maintenance	2 Years	1,176	1,176	1,084	1,029	1,047
Transmission and SEMO charges	2 Years	935	935	984	1,013	1,122
Insurance and Miscellaneous cost	2 Years	1,008	1,008	1,104	1,162	1,150
Rates cost	2 Years	1,315	1,315	1,359	1,385	1,468
Fuel Storage	2 Years	164	164	232	273	290
Total Fixed Costs		**4,598**	**4,598**	**4,763**	**4,862**	**5,077**
Annualised Capital plus Fixed Costs		**93.81**	**97.82**	**96.88**	**99.45**	**100.37**
Energy Market Infra Marginal Rent	1 Year	-0.0007	-0.0007	-1.03	0.202	-0.0007
Ancillary Service Revenue	1 Year	6.69	7.12	7.21	6.93	7.32
Annual BNE Cost		**87.11**	**90.70**	**88.64**	**92.72**	**93.05**
Indexation		0%	1%	3%	3%	2%
Final BNE Cost		**87.11**	**91.61**	**91.30**	**95.51**	**94.91**

Table 3: Costs on BNE Peaker – Worked Example for Option 4

6.5 OPTION 5 – CALCULATE THE BNEFC AND KEEP IN PLACE FOR A MULTIPLE YEAR PERIOD.

This option considers the method used for other price controls where the BNEFC will only be estimated every 3 or 5 years. The costs will have the appropriate indexing applied in the intervening years.

It is suggested that this method will provide more stability for the period that the BNEFC is set and should therefore improve cash flow projections for generators. This option possibly could also create the potential for step changes in the BNEFC at the boundary between the calculation periods, but this could be addressed via the concept of smoothing as discussed above.

Consultation Point 9:

The RAs welcome comments from participants on the proposed Option 5 and the merits of this implementation.

6.6 OPTION 6 – FIXED PRICE FOR NEW ENTRANTS

An option that was suggested in the responses to the Consultation Paper for the Fixed Cost of a Best New Entrant Peaking Plant for the calendar year 2009 was to have a separate mechanism for new entrants. The following points were suggested under this mechanism:

- Leave the current capacity mechanism unchanged for existing generators
- Allow new dispatchable generators to lock-in the value of capacity for a long period (e.g. ten years).
- The lock-in needs to be based on a firm commitment to build such as signing a connection agreement.
- The value of capacity in the year when they entered into a connection agreement to build the facility would then set the revenue for this generator for the next ten years.
- The capacity available to lock-in could be set by the system operators based on system security standards.
- The payment for new entrants could be from the existing capacity pot.

This could be regarded as a more radical option that the other options described in this paper. It is likely to be more effective in reducing the risk for new investors (where the real issue of volatility lies). However, if this option is to be considered further, this will be addressed as part of the second phase of the CPM review (as detailed in section 4).

Consultation Point 10:

The RAs welcome comments from participants on the proposed Option 6 and the merits of this implementation.

The RAs also welcome comments on whether this option should be considered as part of the second phase of the CPM review.

7 REGULATORY DISCRETION

The regulatory exercise is, as has previously been discussed, necessarily subjective. The SEMC wishes to stress that the options in this Consultation, if adopted, will remain subject to the ultimate discretion of the SEMC in application. In unforeseen circumstances the SEMC reserves its right to apply a prudent method in the interest of the health of the CPM and the SEM.

8 NEXT STEPS

Following this consultation, the RAs intend to consider the responses in relation to the BNE 2010 Calculation. The RAs intend to consult on the 2010 BNE Calculation in July 2009 and may use the output of this consultation to feed into the BNE 2010 Calculation.

The RAs are obliged under the TSC to publish the ACPS for 2010 by end of August 2009.

9 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to both Kevin O'Neill at kevin.oneill@niaur.gov.uk and Priti Dave-Stack at pdave-stack@cer.ie by **5pm on Tuesday 7 April 2009**.