Single Electricity Market

CPM Medium Term Review

Work Package 7 - BNE Calculation Methodology

Discussion Paper

07th October 2010

SEM-10-068

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2 INTRODUCTION

In May 2005 the Regulatory Authorities (RAs) set out the options for the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM). 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[1] 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.

On 8 April 2009 the SEM Committee (SEMC) published a consultation paper (SEM-09-035)[2], documenting the scope of work that the SEMC proposed to carry out in relation to a medium term review of the Capacity Payment Mechanism (CPM). The main purpose of this review is to examine if the current design of the CPM can be further improved to optimally meet the objectives of the CPM.

The RAs published a consultation paper (SEM-09-023[3]) on 9th March 2009 which detailed out the options to reduce the 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. Following this consultation on 12th August 2009 the RA published an information paper summarises the responses received to the consultation paper and recommends the next stage for this area to be within the scope of the CPM Medium Term Review.

On 17 November 2009 the SEM Committee (SEMC) published an CPM Medium Term Review Information Paper (SEM-09-105[4]), documenting the scope of work that the RAs plan to carry out in relation to a medium term review of the CPM The main purpose of this review is to examine if the current design of the CPM can be further improved to optimally meet the objectives of the CPM.

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[1] http://www.allislandproject.org/GetAttachment.aspx?id=61cddfef-f617-404d-8c8d-1dc572614675

[2] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=4dde96cc-fdda-458b-9a3c-dc4a00692ac5

[3] http://www.allislandproject.org/GetAttachment.aspx?id=9f4bfc9b-5f60-4ca4-8a84-58158a5bb14f

[4] http://www.allislandproject.org/GetAttachment.aspx?id=3ce981eb-c853-4b03-a87f-1213e9b03daf

The CPM objectives are interlinked with the SEM objectives. The SEM Legislation in Ireland and Northern Ireland provides for a primary SEM Objective and a number of supplementary objectives. The key SEM Objectives as set out in the SEM Legislation are:

- **Competition and Consumers:**
  - The Principal Objective of the SEM is to protect the interests of consumers of electricity in Ireland and Northern Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the Single Electricity Market.
- **Security of Supply:**
  - To secure that all reasonable demands for electricity in Ireland and Northern Ireland are met.
  - To secure that authorised persons are able to finance the activities.
- **Sustainability:**
  - To secure a diverse viable and environmentally sustainable long-term energy supply in Ireland and Northern Ireland.
  - To consider the effect on the environment in Ireland and Northern Ireland of the activities of authorised persons.
  - To promote, where appropriate the use of energy from renewable energy sources. Regulatory Consistency: ensure decisions are transparent, accountable, proportionate, consistent and targeted only at cases where action is needed.

The SEM Committee considers the CPM as a key feature of the SEM design. The SEM Committee believes that extensive analysis and consultation on this topic took place prior to SEM Go Live and that the concept of the CPM should remain in place.

The SEM Committee wishes to satisfy that the correct signals and appropriate incentives or rewards are inherent in the design, so as to meet its objectives optimally. In particular it is mindful that the CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance.

The objectives of the CPM, as defined in the paper 'Capacity Payment Mechanism and Reserve Charging High Level Decision Paper' (SEM-53-05)[5] are:

- **Capacity Adequacy/ Reliability of the system**

  The CPM must encourage both new construction and maintain availability of capacity in the SEM. Security of the system, in both the long and short-term will be the core feature of any CPM.
- **Price Stability**

  The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market.
- **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 will reduce investor confidence in the market and increase implementation costs.
- **Efficient price signals for Long Term Investments**

[5] Capacity Payments Mechanism and Reserve Charging High Level Decision Paper

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.

- **Susceptibility to Gaming**

  The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties.
- **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. Buyers in the SEM should pay in proportion to the benefits they receive.

Ongoing development of SEM and the CPM was always anticipated. it is judged that to date, and likely in the medium term future, the SEM is working well, that there are known challenges ahead but that for now these can be met whilst continuing to meet the SEM Strategic Objectives and the CPM Objectives without fundamentally redesigning the SEM.

In the past the SEMC had 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).

2.1 CONTEXT OF THIS PAPER

This paper covers the review the BNE Calculation Methodology used with in the CPM. It will investigate the following areas;

- CPM Design in other Regions and International experiences in delivering adequate capacity
- BNE Calculation Methodology 2006
- Summary of the Options in the BNE Calculation Methodology Review 2009 - option 2, 5 and 6
- Indexing Methods
- Impact of Options on WACC Calculations

This paper has been created in conjunction with Poyry, the consultants tasked by the RA to aid in the analysis of the CPM review. In 2006 the RAs decided that, for the purposes of determining the annual total for the CPM, the cost of the new entrant generation should be assessed in terms of a “Best New Entrant” (BNE) peaking plant. The proposed methodology was appropriate for a CPM in long term equilibrium; through it was recognised that adjustments may have to be made to achieve this outcome during its interim period. This medium term review paper invites respondents to comment on improving the current BNE Calculation methodology used within the CPM and proposes some options for review.

3 CPM DESIGN IN OTHER REGIONS AND INTERNATIONAL EXPERIENCES IN DELIVERING ADEQUATE CAPACITY

This section provides some information on CPMs in other markets which respondents may find useful when considering their reply to this consultation. As part of consideration of the CPM design the RAs and its consultants have constructed an examination of multiple international capacity mechanism designs around the world.

At a high level, there are three possible electricity market design options for delivering adequate capacity and remunerating generation capacity provision. These include:

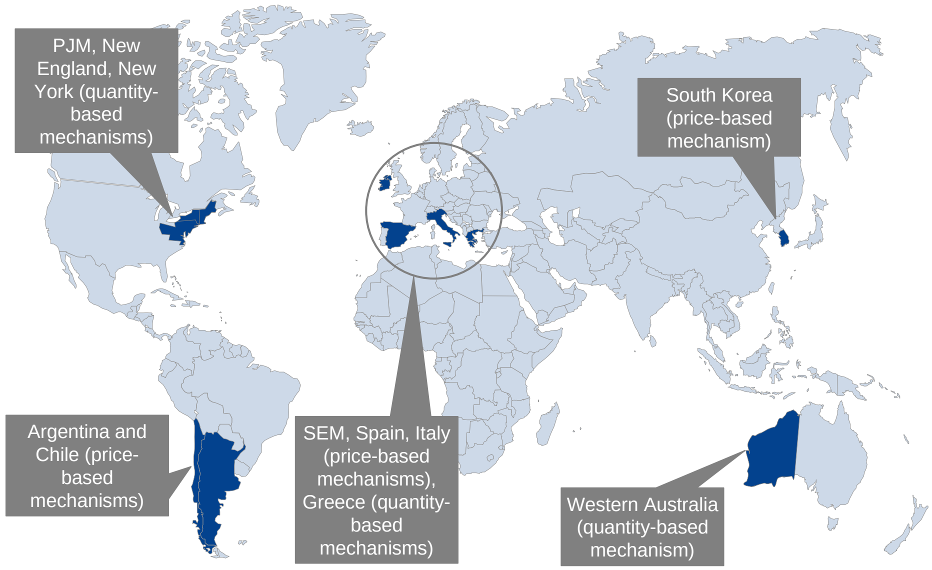
- **Energy only market**: capacity is remunerated within the market price, with no explicit capacity mechanism;
- **Price-based capacity mechanism**: a value is attached to capacity and this is paid to providers of capacity under an explicit capacity mechanism; and
- **Quantity-based capacity mechanism**: the capacity mechanism places obligations on parties to provide adequate generation capacity.

The objective of the comparisons was not to judge which is the better capacity payment mechanism, but to provide a factual review of the mechanics of the selected markets, in order to identify features of interest to SEM. In general there are a few valuable insights enumerated below which could be applied in the SEM context

A detailed analysis of international experiences was conducted and 5 quantity based capacity payment systems in New England, PJM, New York, Western Australia and Greece was reviewed. The key differences between these systems include the bearer of responsibility for securing obligations (whether Load Serving Entities or the ISO); use of auction processes or regulatory processes to set the price for capacity; frequency of review and review horizon for prices and volumes; and the differences in price formation and the role of BNE in price calculation and the definition of a product, which is delivered by the generator and receives a remuneration.

Six price based capacity payment systems in Ireland, Spain, Argentina, Italy, South Korea and Chile were also reviewed. The key differences established include capacity payment timeframes; frequency of regulatory review and review horizon and the operation of separate investment and availability incentives price as in Spain. Figure 4.1 highlights all the markets reviewed.

Figure 4.1 – International markets under review



3.1 QUANTITY-BASED CAPACITY MECHANISMS

Quantity-based mechanisms identify a capacity requirement intended to provide the desired level of generation adequacy. This is translated into obligations to secure the desired level of capacity that are in turn mandated to suppliers or to the ISO. Examples of quantity-based systems assessed are described in the Table 3.1 below and the main differences between them are described in Table 3.2.

Table 3.11 – Quantity-based capacity mechanisms

	Method for securing capacity requirements	**Mechanism name**	**Mechanism review frequency**	**Mechanism review horizon**
New England	ISO secures capacity on behalf of LSEs where capacity obligations are not met by self-supply	Forward Capacity Auction	Annual	Year+3
PJM	ISO secures capacity on behalf of LSEs where capacity obligations are not met by self-supply	Reliability Pricing Model	Annual	Year+3
New York	Obligation on suppliers to contract to ensure adequate capacity	Strip and Spot ICAP Auctions	Biannual	Season+1
Western Australia	Obligation on suppliers to contract to ensure adequate capacity	Reserve Capacity Mechanism	Annual	Year+3
Greece	Obligation on LSEs to ensure adequate capacity (alternative mechanism involves TSO fulfilling LSE's obligations and a regulated price) via Capacity Availability Contracts	Generation Capacity Assurance Mechanism	Annual	Year+1

Table 3.22 – Key differences observed across Quantity-based capacity markets

Features	Key differences observed across markets
Centralized vs. non-centralised obligations	The systems in New York, Western Australia and Greece are non-centralised and the obligation to secure capacity is placed directly upon suppliers. Each supplier can fulfil its individual obligation through self-supply (i.e. effectively contracting with its own generation capacity) or by contracting with capacity providers. Where parties do not meet their own obligations, the ISO/IMO secures residual capacity requirements, with these costs allocated to those with a capacity obligation shortfall. The New England, Colombia and PJM systems used to follow a similar approach. However, the New England and PJM mechanisms have been revised and are now based around centralised capacity mechanisms. In these mechanisms, the ISO secures capacity on behalf of the market. . In Colombia there is a product for reliability options with demand participation and penalties for failure to provide. Also there is a commitment period greater than one year so that capacity providers have greater certainty as to remuneration for capacity provision
Review time horizon	The different mechanisms vary in terms of their review horizon (i.e. the period for which capacity is to be secured). The New York and Greece models have a short-term focus, as they are concerned with capacity provision in the forthcoming season/year only. The New England, PJM and Western Australia markets have a longer-term focus. These mechanisms are centred upon the provision of capacity in a period three years-ahead (five years-ahead for new capacity in the case of New England).
Capacity price	The basis for capacity price formation varies across the models. In the New England model, prices are determined via a descending clock auction, within the confines of an administered cap and collar. In PJM, the capacity price is determined through an auction process, based upon a demand curve determined administratively to reflect the maximum price for a given level of capacity resource relative to reliability requirements. The auction clearing price determines the capacity price in the New York mechanism. In the Western Australian and Greek mechanisms, trade is conducted bilaterally and so the capacity price varies depending upon the bilateral trade price.

Compared with energy-only markets, the performance of quantity-based mechanisms suggests that they are better at delivering capacity although payments to generators are generally higher than energy-only markets. In theory, the advantage of quantity-based systems is that the obligations commit existing plant to remain on the system and encourages additional capacity to be developed. They also provide stable environment for delivery of efficient new generation. Another point is that there should be a commitment from generators to be ready to provide capacity when needed otherwise a heavy penalty should be enforced.

3.2 PRICE-BASED CAPACITY MECHANISMS

Price-based mechanisms establish a price for the provision of capacity. The price is intended to provide an appropriate financial incentive for generators (and demand side participants) to provide capacity necessary to meet the desired level of generation adequacy. Examples of price-based systems assessed are described in the Table 3.3 below and the main differences between them are described in Table 3.4.

Table 3.3 –Price-based capacity mechanisms

	Method for securing capacity requirements	**Mechanism name**	**Mechanism review frequency**	**Mechanism review horizon**
SEM	Generators remunerated for capacity provision through capacity payments	Capacity Payments Mechanism	Annual	Year+1
Spain	Generators remunerated for investing in capacity through an investment incentive payment and for availability through an availability incentive payment	Investment Incentive plus Availability Incentive	Enduring	Enduring
Argentina	Generators remunerated for capacity provision at pre-defined times through capacity payments	Capacity Payments Mechanism	Enduring	Enduring
Italy	Generators remunerated for capacity provision at pre-defined times through capacity payments	Capacity Payments Mechanism	Annual	Year+1
South Korea	Generators remunerated for capacity provision through capacity payments	Capacity Payments Mechanism	Annual	Year+1
Chile	Generators remunerated for capacity provision at pre-defined times through capacity payments	Capacity Payments Mechanism	Biennial	Year+2

Table 3.4 – Key differences observed across Price-based capacity systems

Features	**Key differences observed across markets**
Capacity price	In all cases assessed, the capacity price is determined via an administered process. In many cases the actual basis for the price is opaque. The basis upon which payments are made to capacity providers is generally non-dynamic to prevailing system conditions. In Argentina, Italy and Chile, payments are made at pre-defined times of anticipated tight system conditions, regardless of actual system conditions. The Spanish system, which makes a distinct separation between an investment incentive and an availability incentive, does take some account of system conditions but only to a limited extent. Payments under the investment incentive are dependent upon system conditions at the time of investment, but are not dynamic thereafter.
Mechanism review	The price-based mechanisms vary in terms of their review horizon. The mechanisms in Spain and Argentina have been implemented on a long-term basis and are effectively enduring. The other mechanisms have, in general, annual review periods which focus on the arrangements for the forthcoming year.

Compared with energy-only markets, the performance of price-based mechanisms suggests that they are better at delivering capacity, although at higher market prices than energy-only markets. In theory, the advantage of explicit capacity prices is that they signal the need for existing plant to remain on the system and/or for additional capacity to be developed. They also provide reasonable expectation of cost recovery for efficient new generation (to supplement infra-marginal rent earned from energy market) or demand side provision of capacity. This changes the risk profile for generators.

3.3 AUCTION-BASED CAPACITY MECHANISMS

The RAs also reviewed some auction based capacity mechanisms;

3.3.1 COLOMBIA

The electric energy in Colombia comes mainly from hydro-generation plants (70 % +) and a minor proportion from thermal-generation plants. The price volatility in their spot market has been largely explained by the huge hydraulic component of supply, the seasonal climate (7 months rain and 5 months dry period) and the periodic occurrence of the El Niño phenomenon in Colombia. This posed a considerable risk for generation companies that needed financing for its projects. For these reasons, the Colombia regulator considered it fundamental to implement a remuneration scheme that promotes income stabilization, therefore making investment in generation resources viable to cover efficiently the demand requirements particularly during critical periods of low hydraulic supply. Since December 2006 the "Reliability Charge" (RC) mechanism preserved the essential factors of settlement, billing and collection that guaranteed payment to generation companies in the previous scheme (Capacity Charge). Here the main objective of the RC was to induce supply reliability. The RC is a payment to generators for firm energy; this was a change to ask for a product for in exchange for capacity. The acquisition of this reliability option was by means of an auction in two parts, the first is part was completed by the regulator which acquires Firm Energy Obligations on behalf of the "domestic demand" and the second part was a descending-clock auction.

3.3.2 NEW ENGLAND

The New England auction based mechanism is similar to the Columbian mechanism. It uses a Forward Capacity Auction Market with its objective to purchase sufficient capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing, can participate. It also uses a descending-clock auction.

Capacity auctions can be complex and its initial design will depend on the market, the type of existing plants, the type of future plants and the long term objective of the market. Auctions can also offer different products that can be implemented into the high level design eg; locational zoning signals, reliability options, but two elements which are critical to its success are the length of the capacity contract and the length of the lead time for capacity procurement.

3.4 INTERNATIONAL EXPERIENCE SUMMARY

These international experiences have provided valuable insight into options which could be applied in the SEM. Key lessons include differences in (a) time horizon of regulatory changes; (b) calculation and use of cost of new entry; (c) calculation and use of capacity requirement; and (d) differentiation of incentives for capacity and flexibility. These are discussed in detail in the next section.

3.4.1 TIME HORIZON

Under the current design of the CPM, the RAs are responsible for setting a new ACPS every year. The experiences of other markets suggest considering a review period which sets the ACPS for several years ahead rather than for the following year. Even if the review is on an annual basis, the fact that the payments take effect several years ahead would provide capacity providers, particularly new entrants, relatively greater certainty and ability to respond. The New England, PJM and Western Australia markets for instance are based on the provision of capacity in a period three years-ahead (five years-ahead for new capacity in the case of New England). Thus a new entrant commissioning a plant in 2013 is assured of the capacity payment at the time of commissioning compared to the SEM where the payment for 2013 is yet to be determined.

3.4.2 COST OF NEW ENTRY

The Cost of New Entry or BNE price is another area for learning. In general, other markets reviewed follow SEM-type processes and assumptions in setting the BNE price apart from the auction capacity markets. In Western Australia, the cost of a new peaking plant is taken as the basis for BNE/CONE on the assumption that it is considered an efficient entry point for new capacity. However, the calculated BNE/CONE is inflated marginally to provide a small amount of headroom. In the US markets, baseload gas-fired generation is considered to be the efficient point for new entry and so this capacity is taken as the basis for BNE/CONE calculations.

3.4.3 CAPACITY REQUIREMENT

The markets reviewed use SEM-type inputs in setting capacity requirements. In the New York, PJM and Western Australia markets, the overall capacity requirement reflects forecast demand plus a reserve margin such that generation adequacy criteria are met. While there are differences in terms of the calculation inputs, the underlying approach is similar.

3.4.4 DIFFERENTIATION

There are precedents for incentivising capacity provision and flexibility services separately as the case in Spain highlights. There is also precedent for differentiation between types of capacity providers, differentiating between new entrants and existing generators. The Spanish capacity mechanism for example differentiates between the uses of capacity and the treatment of capacity providers, treating new capacity and existing capacity differently and rewarding thermal and renewable capacity differently.

In theory, the competitive process price is more efficient than an administrative price. In looking at the auction capacity markets a primary concern in designing an auction competitive process is the setting of prices revolves around market power. By increasing the lead times to the point where new entry is possible, entry should limit price and control market powers. Generally, the market to develop new plants is competitive. However, in cases where ownership of existing generation is highly concentrated, it may not be realistic to think that efficient entry would be feasible to limit the influence that a dominant portfolio player may have on a capacity procurement product for a fixed, highly inelastic quantity. A review of the CPM that sets the capacity price by an auction would need to be closely examined to see if there is a need for market power mitigation.

Internationally there are numerous electricity market designs each with its own advantages and disadvantages and each influenced by is internal market participants, the performance of each mechanism is specific to the market design, jurisdiction and market composition and it was difficult to make judgements on performance without context. The RAs will remain focused on ensuring the deliverance of adequate capacity and remunerating generation capacity provision in line with the CPM objectives.

4 BNE CALCULATION METHODOLOGY 2006

In the consultation paper on the BNE Calculation ("Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism", SEM-124-06, 15th September 2006)[6], 3 options for calculating the 'BNE' element were proposed:

1. Assessing the market equilibrium price of a peaking plant (marginal cost of incremental capacity) in the SEM based on an assessment of VOLL, LOLP and the peaking plant's forced outage probability.
2. Assessing the cost of peaking capacity in the SEM by estimating the full project costs that would be incurred by a developer of a new BNE peaking plant and taking into account the assumed infra marginal rent realised from participation in the energy and ancillary service markets.
3. Assessing the cost of peaking capacity in the SEM based on a narrowly defined role for the peaking plant, that of a 'social benefit' operating as contingency reserve only, and adjusting the investment criteria for a BNE peaking plant given this narrow role.

The SEM-124-06 paper invited views on the possible approaches set out in the paper for determining the fixed costs of a BNE peaking plant for the purposes of setting the Annual Capacity Payment Sum.

Option 2 was decided upon and has been used for the last number of years. Now that the SEM and CPM has been established for a few years, at this stage the RAs wish to revisit Methodology Option 1:

Option 1 uses the following formula: $MCR = (1 – FOP) * LOLP * VOLL$

The VOLL (Value of Lost Load) term in this formula represents the amount that customers are willing to pay in order not to be cut off (i.e. what they are willing to pay to retain their supply), when load is being lost (i.e. when some customers are being involuntarily interrupted).

The LOLP (Loss of Load Probability) term, Can be calculated as an indicator of the Loss of Load Expectation (LOLE). The LOLE is a statistical measure of the likelihood of failure and does not quantify the extent to which supply fails to meet demand. The use of LOLE to assess Generation Adequacy is an internationally accepted practice. (With an hourly load model as used in these studies the LOLE will be equal to and is sometimes called the loss of load probability (LOLP) but this term is more properly reserved for the dimensionless probability values). The calculated adequacy level is then compared to a standard to assess the adequacy of the system. The current standard is a value of 8 hours per year.

The Forced Outage Probability (FOP) term is the probability that a generator is out of service for reasons other than scheduled maintenance. This means that the available capacity of the system is the aggregate of generators' availabilities, each of them dependent on its FOP.

All of the input parameters are considered on an annual basis, and over the past number of years most have been fairly constant.

The table 5.1 shows the value of MCR using the annual figures consulted on in the SEM:

[6] http://www.allislandproject.org/GetAttachment.aspx?id=61cddfef-f617-404d-8c8d-1dc572614675

Table 5.1 – Option 1

Option 1	**2007**	**2008**	**2009**	**2010**	**2011**
VOLL (€/MWh)	10,000	10,000	10,390	10,273	10,295
FOP (%)	2%	2%	2%	2%	2%
LOLP (h)	8	8	8	8	8
MCR (€/kW/year)	78.40	78.40	81.46	80.54	80.71

As can see the above figures are comparable with the BNE calculations (see table 5.2 below):

Table 5.2 – Option 2

Option 2	**2007**	**2008**	**2009**	**2010**	**2011**
BNE Value (€/kW/year)	64.73	79.77	87.12	80.74	78.73

The two sets of figures are shown on the graph below.

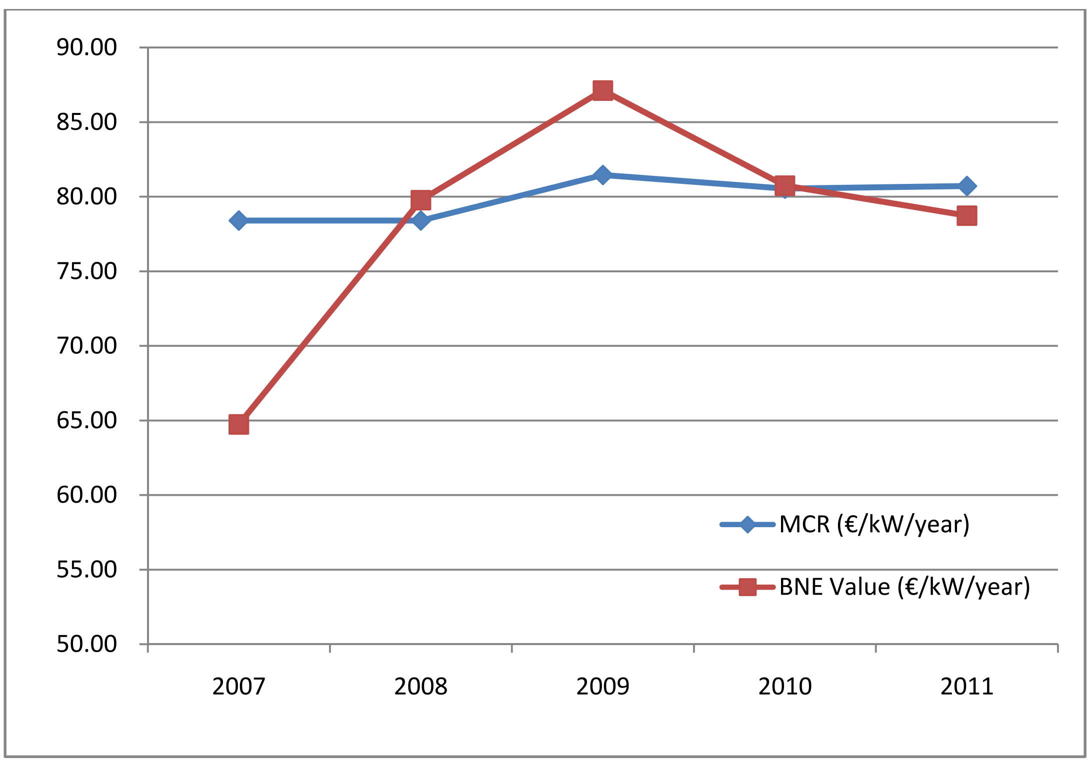


Figure 5.1 – Option 1 and Option 2 comparison.

Overall, Option 1 has produced a comparable value with the BNE process (Option 2), which if nothing else shows that the BNE values were within range (The 2007 BNE value was below the range as this was where Infra-marginal rent was deducted).

The reduced volatility of option 1 should be noted, the main variable is VOLL, which for the last number of years has been adjusted using the HICP index. Its value in subsequent calendar years has been determined by taking its values in the preceding year and up-rating it by applying the weighted average of the year-on-year increase in the Irish Harmonised Index of Consumer Prices (HICP) (using a weight of two-thirds) and the UK HICP (using a weighting of one-third) in the July of the preceding year by comparison with that a year earlier. Indexing options are discussed further in the oncoming section of this paper.

The above method of using LOLP and VOLL has been used before. In the UK during the period 1990-2001 their market model was based on a compulsory day a head pool, and the system marginal prices were calculated on a half-an-hour basis. Their CPM was also based on estimates of VOLL and LOLP. Within this model the generating plants declared their availability in each half hour, and the CPM value was equal to LOLP for the half hour period, multiplied by the difference between the VOLL and the plants bid price (if they were not dispatched) or the system marginal price (if they were dispatched).

This mechanism was not without criticism, as it was vulnerable to gaming strategies by generators who could often manipulate the pool price by withdrawing plant from the market at key times i.e. certain companies would artificially increase LOLP by declaring certain units unavailable and therefore increasing capacity payments. Another issue with the mechanism was that it was seen to rewarded shortage rather than rewarding new investment.

Where as the UK model was based on a half-an-hour basis, the above option 1 would be an annual calculation with an increased focus on the VOLL, LOLE and FOP annual inputs. Following consultation of SEM-124-06, Option 1 was discounted due to concerns relating to the difficulty surrounding the determination of VOLL for the SEM as it was likely to result in sub optimum assessment of the market equilibrium price of a peaking plant. However, Option 1 has some merits:

1) Option 1 follows economic theory and therefore would not significantly change the current method of calculating the capacity pot.
2) The RAs currently calculate and consult on the inputs to Option 1 on an annual basis.
3) The VOLL and LOLE inputs have been determined and are shown to be comparable with the BNE method, thus suggesting that they are in the correct range.
4) Option 1 is very simple to calculate (assuming the VOLL calculation methodology is maintained) and produces an output that is less volatile and more predicable.

Methodology Option 1 is in keeping with the objectives of stability, fairness and simplicity but is it not without its criticisms. The RAs wish to revisit and obtain comments on Methodology Option 1.

5 SUMMARY OF THE OPTIONS IN THE BNE CALCULATION METHODOLOGY REVIEW 2009

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" -(SEM-08-109[7]). In this decision paper, the SEMC signaled 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). In 09th March 2009 the RAs issued a consultation paper on the "Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology" – (SEM-09-023[8]) addressing this area. The RAs had considered the options available that may be used to reduce the perceived volatility in the BNEFC. These are summarised below;

- Option 1 – Calculate BNEFC on an annual basis with all components recalculated annually.
- Option 2 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years
- Option 3 - Calculate BNEFC on an annual basis with all components recalculated annually. Smoothing is then applied.
- Option 4 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years. Smoothing is then applied.
- Option 5 – Calculate the BNEFC and keep it in place for a multiple year period.
- Option 6 – Fixed price for new entrants

Following the consultation period on the 9th August 2009 the RAs issued an Information Note (SEM-09-085)[9] detailing the responses and decided that Option 2, Option 5 and Option 6 be reviewed within the medium term review.

Overall most respondents to the consultation favoured that these matters be considered within the medium term review and some respondents had questioned if there really was an issue with the BNE fixed cost and suggested that very limited changes to the methodology was required.

6 REVIEW OF OPTION 2

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

The current CPM involves annual cycles of changes to the overall ACPS pot, the BNE price and capacity requirement. The advantage of this annual cycle is that the capacity pot is closely linked to changes in capacity requirements and system need. In addition, the annual BNE price closely reflects the prevailing investment climate affecting new entrants. However, its main drawback is that it creates significant uncertainty in the level of future payments. For participants and new entrants, it means investing with the risk that the level of capacity payments considered when making the investment could change significantly in the next years if the RAs change the overall

[7] http://www.allislandproject.org/GetAttachment.aspx?id=b1e45b36-fdfb-4fa2-8b0a-d4767425d880

[8] http://www.allislandproject.org/GetAttachment.aspx?id=9f4bfc9b-5f60-4ca4-8a84-58158a5bb14f

[9] http://www.allislandproject.org/GetAttachment.aspx?id=3ce981eb-c853-4b03-a87f-1213e9b03daf

size of the pot or any of the parameters for calculation of the pot. Settling on a technology type in calculation of BNE over a period of years, or a specific cost of capital (WACC) assumption and life of plant for a period of several years would improve the predictability of the ACPS pot and its constituents.

In the BNE Calculation Methodology Review 2009 consultation paper, option 2 proposed 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. These elements would include both choice variables, such as the technology of the peaker, the choice of fuel, the sitting 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.

In the BNE Calculation Methodology Review 2009 consultation paper, option 2 proposed a worked example showing the costs of the BNE over the 5 years. Note that the figures used in this paper were fictitious and for demonstration purposes only.

Within this example several elements were fixed for 3 years, such as site costs, pre and post finance costs, other fixed cost elements were fixed for 2 years and the economic parameters (WACC) being reviewed on an annual basis.

Some of the international mechanisms that have been researched, for example PJM, Western Australia have their mechanism elements reviewed in a horizon of 3 years (5 years for New England), but it should be noted that these are mainly quantity-based capacity mechanisms.

Based on the lessons learned from analysis of various international experiences, the RAs consider that a 'Component Period Horizon' of 3 years / 5 years can bring some stability and certainty to the volatility in the capacity pot year on year. They consider that there is merit in a commitment period greater than one year in that capacity providers will have greater certainty as to remuneration for their capacity provision which would provide the capacity providers, particularly new entrants, greater certainty and ability to respond.

This option is not with its disadvantages, it the time period is extended and their has been significant changes to the market both in county and internationally, either structurally or financially then the proposed option may not truly accurately reflect the changes within the market place as it still allows the possibilities of a step change, although not every year.

The RAs opinion of this option is that it would help provide some additional stability for generators, as the BNE Costs would be tied down for a number of years. However, this stability will be in the short term relative to the length of an overall investment. Based on the movements of both commodity and financial markets, it is unlikely that all parameters could be set for a period of 5 years and reviewing some parameters over a shorter period increases the level of perceived volatility.

The RAs welcomed comments from participants on the proposed method for Option 2 including any additional options that may help to reduce the perceived volatility.

It should be noted that if there is a three or five year period of fixing pricing then appropriate indexing should be used. The following section looks at some of the indexing methods that could be considered.

7 INDEXING OVER SEVERAL YEARS

7.1 WHY DO WE USE INDEXING INDICES?

A price index can be best described as is a normalized average (typically a weighted average) of prices for a given class of goods/services in a given region, during a given interval of time. It is a statistical tool that helps to compare how these prices, differ between time periods or geographical locations. In general these indices can help generators and other parties with their business plans and can be a useful guide to investment. To continue with the worked example highlighted in section 6, 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. 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. This would provide certainty to new entrants allowing them to more easily predict future payment streams. Parameters that could be indexed includes the BNE price itself, EPC costs etc.

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.

7.2 INDEXING OPTIONS AVAILABLE

The RAs have detailed four indexing options below which were suggested in previous consultation papers. These are:

- RPI - the Retail Prices Index (RPI) is the most familiar general purpose domestic measure of inflation in the United Kingdom. It is available continuously from June 1947. The uses of the RPI and its derivatives include indexation of index-linked gilts. The Government uses it for uprating of pensions, benefits and index-linked gilts. It is commonly used in private contracts for uprating of maintenance payments and housing rents. It is also used for wage bargaining.
- CPI - the consumer prices index. It is the measure adopted by the Government for its UK inflation target. The Bank of England's Monetary Policy Committee is required to achieve a target of 2 per cent. In the June 2010 Budget, the Chancellor announced the Government's intention to also use the CPI for the price indexation of benefits and tax credits from April 2011. Prior to 10 December 2003, the CPI was published in the UK as the harmonised index of consumer prices (HICP). In Ireland the CPI is different; it is designed to measure the change in the average level of prices paid for consumer goods and services by all private households and foreign visitors to Ireland.
- HICP - the harmonised Index of Consumer Prices (HICP) is an indicator of inflation and price stability for the European Central Bank (ECB). It is a consumer price index which is compiled according to a methodology that has been harmonised across EU countries. The euro area HICP is a weighted average of price indices of member states who have adopted the euro.
- PCCI - the Power Capital Costs Index. IHS CERA produce a Power Capital Costs Index periodically that is designed to capture the movements relevant for power procurers in North America[10]:

[10] Provided by IHS CERA http://www.ihsindexes.com/

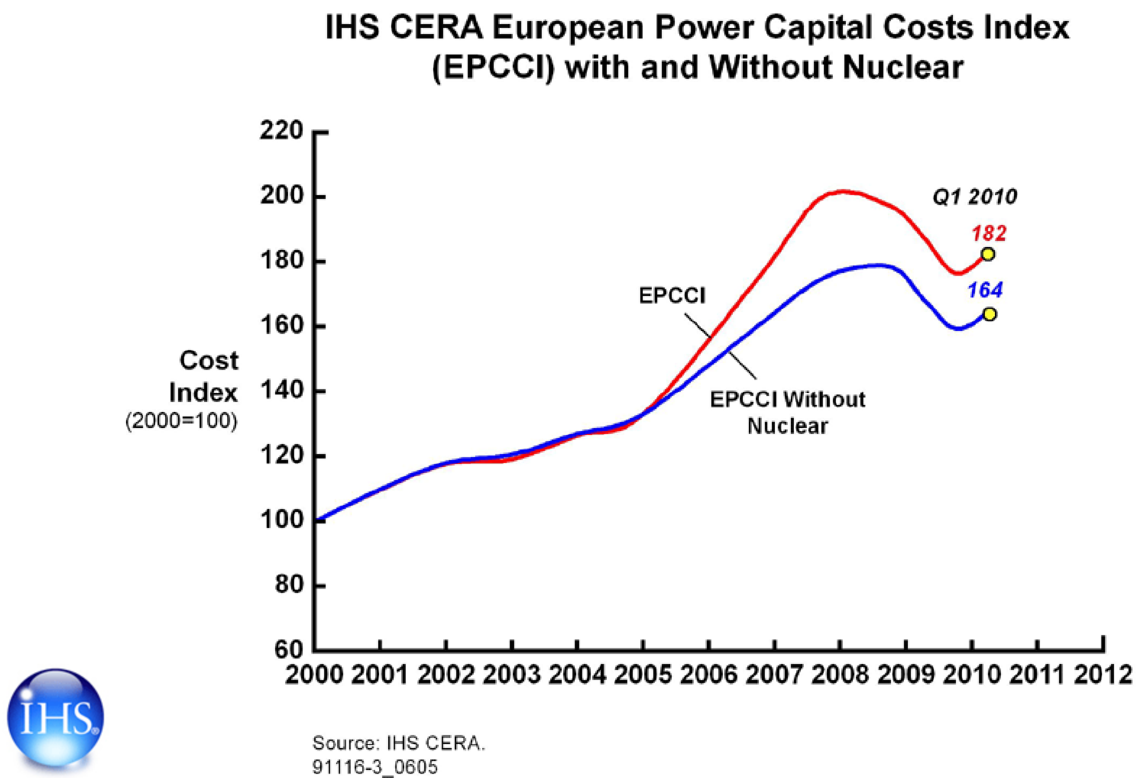


Figure 7.1: EPCCI by IHS – CERA - http://www.ihsindexes.com/

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. Other possible indices include a weighted inflation index (combining the impact of CPI in Northern Ireland and the Republic of Ireland) or specialised CPI indices such as the Utilities or Housing and Utilities sub-segments of the CPI.

The disadvantage of generic inflation indicators is that they may not capture drivers for specifics costs in power plants such as the cost of specialised components or global commodity drivers that have a disproportionately larger influence on the power sector compared to the larger economy such as changes in steel prices. In that case using specialised indices such as the European Power Capital Cost Index (EPCCI) could be more useful. The EPCCI is a proprietary index that tracks and forecasts the costs associated with the construction of a portfolio of power generation plants in Europe. 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.

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.

Figure 7.2 on the next page provides the results of indexing the BNE price in 2007-2010 compared with the outturn for those years, while Figure 7.3 compares the impact of indexing selected inputs over 2007-2010 periods with the outturn. The performance of indexation depends on three metrics: (a) choice of the inflation index; (b) period of indexation; and (c) selection of subsets to index. As Figure 7.2 highlights, the All-island Housing and Utilities sub-sect of CPI provides the closest match both in terms of the absolute level of BNE price and the price profile over time. Similarly the EPCCI and the utilities subset of CPI provide a similar profile, even as the absolute price bears little resemblance to the outturn. Generic inflation indices however are poor at approximating the outturn BNE price.

The choice of period of indexation is also important. As Figure 7.2 highlights, the match between outturn and the indexed prices is closest in 2008, however by 2010, there is significant divergence between the outturn and the indexed price. Even for the best performing index, the All-island Housing and Utilities CPI, the divergence increases from approximately €/3.5 kW to €10.2/kW. There is therefore need for a balance between short periods of indexation which allow the CPM to broadly track changes in the market and the investment climate, and longer periods which increase the level of investor certainty.

Figure 7.2 – Indexing BNE price over 2007-2010, comparisons with outturn

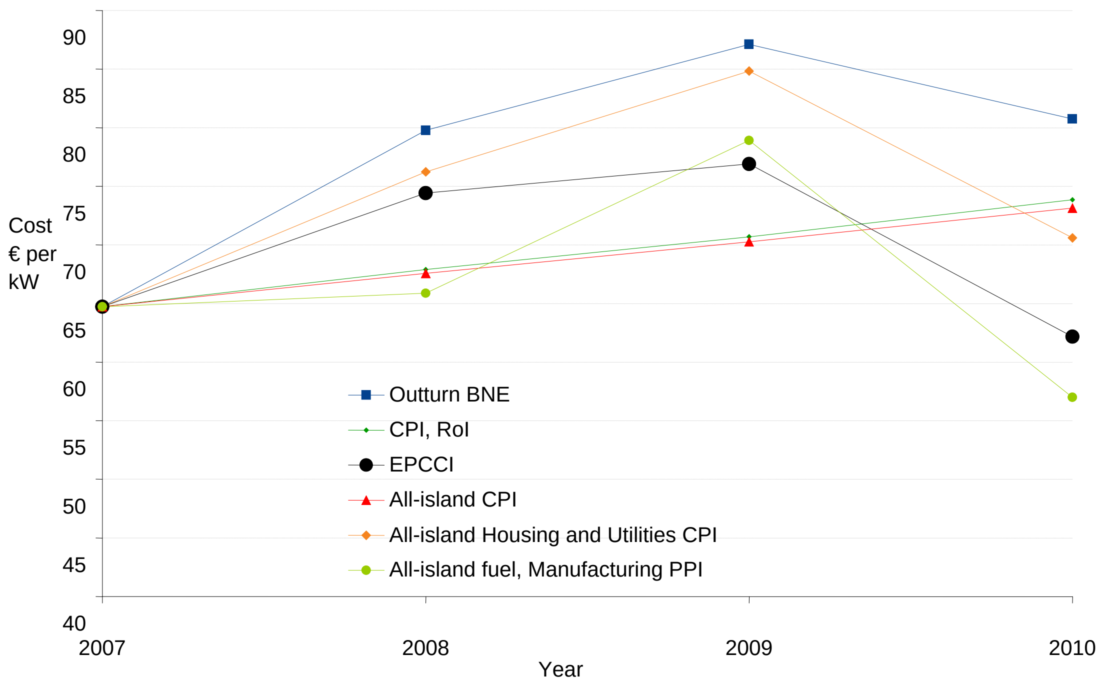
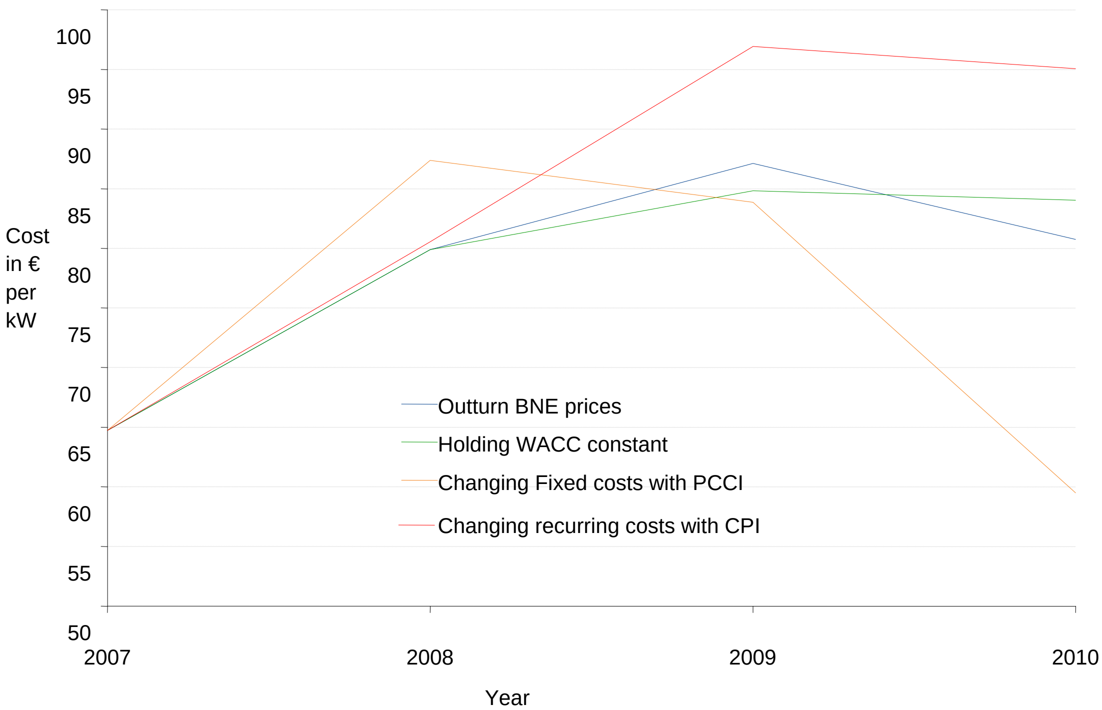


Figure7.3 – Indexing selected variables, 2007-2010, comparisons with outturn



Finally the subset of what to index is important. By definition, indexing the actual BNE price provides the highest level of certainty for new entrants, also holding constant the WACC (see section 10 of this report) at current levels all other things being equal, brings a higher level of predictability to the outturn BNE.

The level of payments of the current CPM can and does change annually with the revision of the ACPS and BNE price. The result of this uncertainty regarding future payments is a higher cost of capital for new entrants. Indexing the BNE price may reduce the administrative costs and the regulatory risks implicit in the annual cycle of ACPS calculations. The main drawback is that it would weaken the link between the BNE and the investment climate as well as the link between current need for additional capacity and actual investment, since investors will be basing their decision on BNE prices and presumably capacity requirement calculated a few years before.

If indexing is used, the RAs welcomed views on which of the above would be the most appropriate method of indexing. In addition, the RAs welcomed suggestions from participants on other indexing options.

8 REVIEW OF OPTION 5

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

In keeping in line with pot stability this method will provide more stability for the period that the BNEFC is set and should therefore improve cash flow projections for generators. It is a similar mechanism to that detailed in option 2. In this option the RA would option considered the method used for other price controls where the BNEFC will only be estimated every 3 or 5 years.

If Option 5 was to be considered, the costs will have the appropriate indexing applied in the intervening years based on some of the indexing methodology in the pervious section. The RAs welcomed views on Option 5 and which of the above would be the most appropriate method of indexing.

The RAs also believe that this option would have material effect on the confidence of investors, would improve certainty of projected revenues in the medium term and would significantly reduce volatility. The same issues that impact Option 2 also apply here; i.e. these options possibly could have the drawback of potentially creating a stepped changed in the BNEFC at the boundary between the calculation periods. An alternative scenario could be implied in setting certain elements to be reviewed at intervals over the 3 to 5 year period, with focus that all the elements could be reviewed at some point in the cycle period so that their would be a minimal stepped change year to year and no major stepped change between cycle years. The RAs also welcomed views on this alternative scenario.

9 REVIEW OF OPTION 6

Option 6 - Fixed price for new entrants – the new entrant scenario

The intention of the fixed price for new entrant scenario is to provide an increased level of stability to new entrants in order to encourage market entry, and also appropriate market exit for older plants. The RAs wish to investigate how a new entrant guarantee would impact the CPM. This scenario will be looked at in dept with Poyry, the consultants working with the RA during this project.

There are several ways to provide a new entrant guarantee, these include:

- Guaranteeing the BNE price at the time of commissioning for all new entrants adjusted by capacity credits, for a few years, and leaving the residual pot to be allocated among existing generators;
- Guaranteeing a BNE price only to conventional generators for a period of several years, and allocating the residual to renewable and existing generators.

The rationale for the latter, which is similar to the Spanish model, is that renewable generators are already incentivised through the Renewable Energy Feed In Tariff (REFIT) in the Republic of Ireland and the Northern Ireland Renewables Obligation scheme.

There are several markets that provide incentives for new entrants notably Colombia and Spain. In the Colombian market, capacity payments are made through an energy obligation scheme (OEF) which commits the generator to make available the qualifying quantities of energy in periods of scarcity (defined as periods in which the spot price exceeds the pre-defined Scarcity Price). Participating generators are paid a guarantee based on the final prices set by a descending clock auction. New entrants are guaranteed the payment for 20 years, while existing generators are paid on an annual basis, with the possibility of a roll-over in case there are no auctions.

Since 2007, the capacity mechanism in Spain has had two components; an investment incentive intended to encourage investment in new capacity and an availability incentive. Under the investment incentive, new conventional plants larger than 50MW receive an administratively fixed €/MW/year payment during their first 10 years of operation[11] . The actual value of the guarantee is dependent on the prevailing system margin at the time of investment. Existing generators are only eligible for this payment in cases of significant investment in upgrading their capacity. Renewable and cogeneration plants are not eligible for the investment incentive payment on the basis that they are already supported through other initiatives. The availability incentive on the other hand is intended to secure an availability service in annual blocks through bilateral contracts with the system operator. Under transitional arrangements payments are based on a value of €4.808/MWh. It is intended that only peaking plant and manageable hydro will be eligible to provide this service.

The new entrant scenario improves the certainty for new entrants and should on balance, help to deliver new capacity when it is needed by reducing the cost of capital. However it could create uncertainty regarding the level of payments for existing generators, resulting in calls to increase the size of the ACPS pot or provision of grandfathered minimum payments to existing generators to protect them from diminished revenues.

One argument against a new entrant guarantee is that it discriminates against existing older generators, and therefore goes against the fairness principle, a major objective of the CPM. However different generators can enter the market for different reasons under different conditions, for example; they may have different installation time, investment costs, price forecasts when making the decision to invest, etc. It should not be termed discrimination if these generator agents enter the market under different conditions. The RAs would consult on the amount of guarantee to provide (and whether flat or adjusted for reliability); the period for guarantee (how long to provide it). Other questions would include whether to link it to a measure of capacity requirement to prevent over-investment. Moreover, while the advantage is that it significantly improves certainty for new entrants, there is a renewed risk of diminished payments once the guarantee is exhausted.

Option 6 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). Later on in the next work package the RAs will look at developing this scenario in line with Poyry and investigating and what impact it would have on a future model of the SEM. The RAs welcomed views on Option 6.

10 IMPACT OF OPTIONS ON WACC CALCULATIONS

In the BNE calculations, the calculation of WACC is a key area that historically has resulted in a lot of comments from Market Participants. The RAs in this section intend to look at the methodology used in calculating the various WACC parameters to ensure the approach is fully transparent and that all assumptions used are clear and understood.

10.1 WACC PARAMETERS

The weighted average cost of capital (WACC) is the rate that a company is expected to pay on average to all its security holders to finance its assets. Calculating it requires knowing the rates of return required for each source of capital. The WACC methodology is widely used by investors to estimate the required return / Cost of capital in large capital projects and the RAs believe it is an accurate reflection of reality for investors.

[11] This 10-years condition was aimed to reward plants, which have entered the system after the market started in 1998.

In its simplest terms; the Weighted Average Cost of Capital (WACC) = (Cost of Debt*Gearing) + (Pre Tax RORE*(1-Gearing))

The WACC parameters are key to the establishment of the final annualised cost, A number of these inputs parameters can have a potential volatile significant impact such as the Debt Spread, Debt Premium, Equity-Risk Premium, Gearing and Inflation. As these inputs have a significant impact on the WACC settings and under the CAPM framework can materially dictate the outcome, therefore have an impact on the annualized fixed costs of the BNE Peaker.

In these times of international financial uncertainty the CAPM approach used in the WACC methodology can have an impact on annual inputs. Within the BNE calculation the RAs commission their consultants to provide a comprehensive summary of the assumptions in their recommendation of the WACC to be used for the BNE Peaker. Within this process the RAs require a study to be compiled in both jurisdictions.

A summary of the WACC parameters provided by CEPA in the 2011 BNE decision papers is detailed in table 10.1 below. The 2010 WACC values have been included to allow a comparison.

	RoI			UK		
Element	**2010**	**2011 Low**	**2011 High**	**2010**	**2011 Low**	**2011 High**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
Debt premium	3.50%	1.50%	2.50%	3.00%	1.50%	2.00%
Cost of debt	**5.38%**	**3.00%**	**5.00%**	**4.75%**	**3.00%**	**4.00%**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
ERP	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.20	1.30	1.25	1.20	1.30
Post-tax cost of equity	**7.81%**	**6.90%**	**9.00%**	**7.69%**	**6.90%**	**8.50%**
Taxation	12.5%	12.5%	12.5%	28%	28%	28%
Pre-tax cost of equity	8.93%	7.89%	10.29%	10.68%	9.58%	11.81%
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**6.80%**	**4.95%**	**7.11%**	**7.13%**	**5.63%**	**7.12%**

Table 10.1 – *Summary of WACC parameters recommended by CEPA/PB for the 2011 BNE*

In summary, for 2011 CEPA/PB recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 4.95% - 7.1% in the Republic of Ireland and 5.6% - 7.1% in the UK.

The RAs used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2011. The values to be used are the mid point of the ranges recommended by CEPA/PB. The WACC values used for the BNE Peaker for 2011 are detailed in Table 10.2.

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

Table 10.2 –*WACC values to be used for the BNE Peaker for 2011*

The past few years the BNE has been based in Northern Ireland as such the UK elements have been used in WACC values in this methodology.

The WACC parameters present an interesting theoretical question. The SEMC's initial view is that these parameters are (mostly) not project-specific and as such should not warrant infrequent or smoothed evaluation. This type of volatility is on the whole accepted as being part of the challenge a commercial enterprise faces; in that there is a difference between servicing a debt to a bank and receiving monies from the marketplace to do so. The RA's CPM is not designed in principle to mitigate financial turmoil; and it is certainly the case that the volatility of the WACC parameters is outside the control (though not in the strictest sense given the SEM design) of the RA's.

Smoothing is difficult to advocate for the WACC, for example allowing a lag on the tax rate would generate a cross-over effect if the BNE plant moves from ROI to NI that would not map to any sense of real-world costs. There is thus concern that applying a frequency / smoothing effect to the WACC parameters would truly distort the market signals and take the CPM into a function for which it was not designed.

Notwithstanding the above argument, there are some elements of the WACC that relate to the specific peaking investment; namely gearing, beta and investment horizon. These probably don't need to be reviewed every year, and the RAs which to obtain responds views on the proposal to re-examine these only once every three years. For the other parameters (tax rates, inflation etc) it is deemed inappropriate to re-examine these at any interval greater than one year.

10.2 ALTERNATIVES TO WACC

In a pervious consultation one respondent had suggested using a Discounted Cash Flow (DCF) analysis, this is a method of valuing a project, company, or asset using the concepts of the time value of money. It can also be used to estimate the attractiveness of an investment opportunity. DCF analysis uses future free cash flow projections and discounts them to arrive at a present value, which is used to evaluate the potential for investment. If the value arrived at through DCF analysis is higher than the current cost of the investment, the opportunity may be a good one.

Adjusted Present Value (APV) is another business valuation method that the RAs looked at. APV is the net present value of a project if financed solely by ownership equity plus the present value of all the benefits of financing. Technically, an APV valuation model looks pretty much the same as a standard DCF model. However cash flows would be discounted at the unlevered cost of equity, and tax shields at the cost of debt. APV and the standard DCF approaches should give the identical result if the capital structure remains stable.

These models are powerful, but they do have shortcomings, as with any model the DCF model is only as good as its input assumptions. Depending on what you believe about how a company will operate and how the market will unfold, DCF valuations can fluctuate, giving uncertainty and volatility to the method. It is arguable whether the results of these methods would be more robust than the current WACC method.

10.3 WACC CONCLUSIONS

The financial credit crunch crisis has placed an unprecedented premium on any potential risk and revenue uncertainty. It is essential that the rate of return earned by a BNE must be sufficient to cover the risk of entering the SEM. In the current process the RAs and its consultants will endeavor to review the associated parameters in light of the economic climate, they will ensure that that these parameters and assumptions are realistic and have been collated in line with international best practices. The RAs believe that reviewing the proposed WACC value in light of responses to each consultation offers them a unique opportunity to continuously review and develop the approach to ensure it is transparent and that the assumptions made are clearly understood.

The RAs welcome comments and note that they could reflect the concerns that have been raised in previous consultations on the BNE Peaker costs. The RAs have endeavored to make the 2011 BNE Calculations as transparent as possible and published extensive data and assumptions on the WACC parameters as determined by external consultants (CEPA/PB report). They will seek to make the WACC calculations for the 2012 BNE Calculations as transparent as possible and will look at methods of reducing the level of volatility by continuing the work described in the 2011 BNE paper by outlining in significant detail the determination of the WACC parameters. The RAs also wish to receive in addition to comments in relation to Option 2 (section 6 of this report) in keeping the certain WACC parameters fixed for a number of years and what appropriate indexing should be used.

11 NEXT STAGE

In responding to the above options the RAs wish to remind respondents of the original criteria a CPM should fulfil as defined in 'Capacity Payment Mechanism and Reserve Charging High Level Decision Paper ' (15 July 2005 - AIP/SEM/53/05[12])

- Incentivise appropriate levels of market entry and exit;
- Encourage an efficient mix of plant types;
- Not "double pay" generators;
- Reduce risk premium for investors;
- Is compatible with the energy market;
- Encourage short-term availability when required;
- Encourage efficient maintenance scheduling;
- Not increase costs to customers for desired security margin;
- Reduce market uncertainty;
- Not unfairly discriminate between participants; and
- Be transparent, predictable and simple to administrate.

The next stage of the Medium Term review is looking at the remaining work packages (6, 8, 9 and 10) focusing on;

- Treatment of Generator types in the CPM
- Incentives for Generators
- Timing and distribution of Capacity Payments
- Option for Caps and Floors
- Impact of the CPM on Customers.

A Further Discussion paper will be published in Q4 2010 detailing these work packages.

[12] http://www.allislandproject.org/GetAttachment.aspx?id=2759ca55-46ab-40c4-911f-d1138d97a6d9

12 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Discussion Paper, and should be addressed (preferably via email) to both Jody O'Boyle at jody.o'boyle@niaur.gov.uk and Clive Bowers at cbowers@cer.ie by **5pm on 12th November 2010**.

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.