# Single Electricity Market

# CPM Medium Term Review

# Work Packages 1 to 5

# Historical Analysis of CPM

# And Proposed Decisions

## Discussion Paper

**23rd July 2010**

**SEM/10/046**

# 1 CONTENTS

# 2 INTRODUCTION

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).

On 11 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[2] (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 (BNE FC) and the Annual Capacity Payment Sum (ACPS).

The RAs have already produced a consultation document (SEM-09-023)[3], relating to the perceived volatility of the CPM and proposed a number of options to help reduce the level of volatility. In this paper, the SEMC signaLled its intention to carry out a further review of the CPM in the medium term. The main purpose of this review is to examine if the current design of the CPM can be further improved to optimally meet the CPM objectives.

The RAs have now completed three iterations of calculating the capacity pot. The RAs believe that the SEM is now well enough established and there is sufficient historical data and opinions collated from the various consultation processes to allow the RAs to carry out a review of the CPM.

On 8 April 2009 the SEM Committee published a consultation paper (SEM-09-035)[4], documenting the scope of work that they proposed to carry out in relation to a medium term review of the Capacity Payment Mechanism.

The RAs, on behalf of the SEMC, intend to review the current process used for distributing the capacity pot among generators and the calculations for payments by suppliers. The SEMC considers the CPM as a key feature of the SEM design. The SEMC believe 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 SEMC 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 the SEMC are mindful that CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance.

On 17 November 2009 the SEM Committee (SEMC) published an CPM Medium Term Review Information Paper (SEM-09-105)[5], documenting the scope of work that the RAs plan to carry out in relation to a medium term review

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[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-decision.aspx?article=48679b7e-aa47-49bf-9a82-1c8e4c863014

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

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

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.

On 18 November 2009, the RAs hosted a workshop on the methodology used to calculate the Capacity Requirement used in the determination of the Annual Capacity Payment Sum.[6]

In the Information paper, the RAs decided that the work on the CPM Medium Term Review should be carried out in two phases - the first looking at the historical aspects of the CPM design and the second looking at possible CPM enhancements in more detail.

The historical phase is to be completed first and is made up of 5 work packages covering the following areas:

- Work Package 1 - Historical Analysis of CPM
- Work Package 2 - Review of Capacity Requirement
- Work Package 3 - Deduction of IMR & AS & BNE Peaker Plant Options
- Work Package 4 - BNE Peaker Plant Fuel Options
- Work Package 5 - Exchange Rate for CPM

This paper covers the **Work Packages 1 – 5.** The purpose of this paper is to document the work carried out by the RAs on the CPM Medium Term Review and allow comment on the work completed to date by interested parties.

[5] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=e8b5dd74-5be7-4dc6-a17d-20aadb247683

[6] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=ba1ce3a7-23ff-4dd3-8a88-cd715106eeaa

# 3 WORK PACKAGE 1 - HISTORICAL ANALYSIS OF CPM

The RAs assessed the distribution of capacity payments on availability, particularly at times when capacity is needed most. In order to carry this activity out, the RAs analysed the CPM market date from November 2007 to June 2009. The RAs on behalf of the SEM Committee would like to acknowledge the support provided by SEMO in providing the raw data used for this analysis.

## 3.1 KEY HIGHLIGHTS FROM HISTORICAL ANALYSIS

### 3.1.1 DISTRIBUTION OF PAYMENTS BASED ON PLANT TYPE

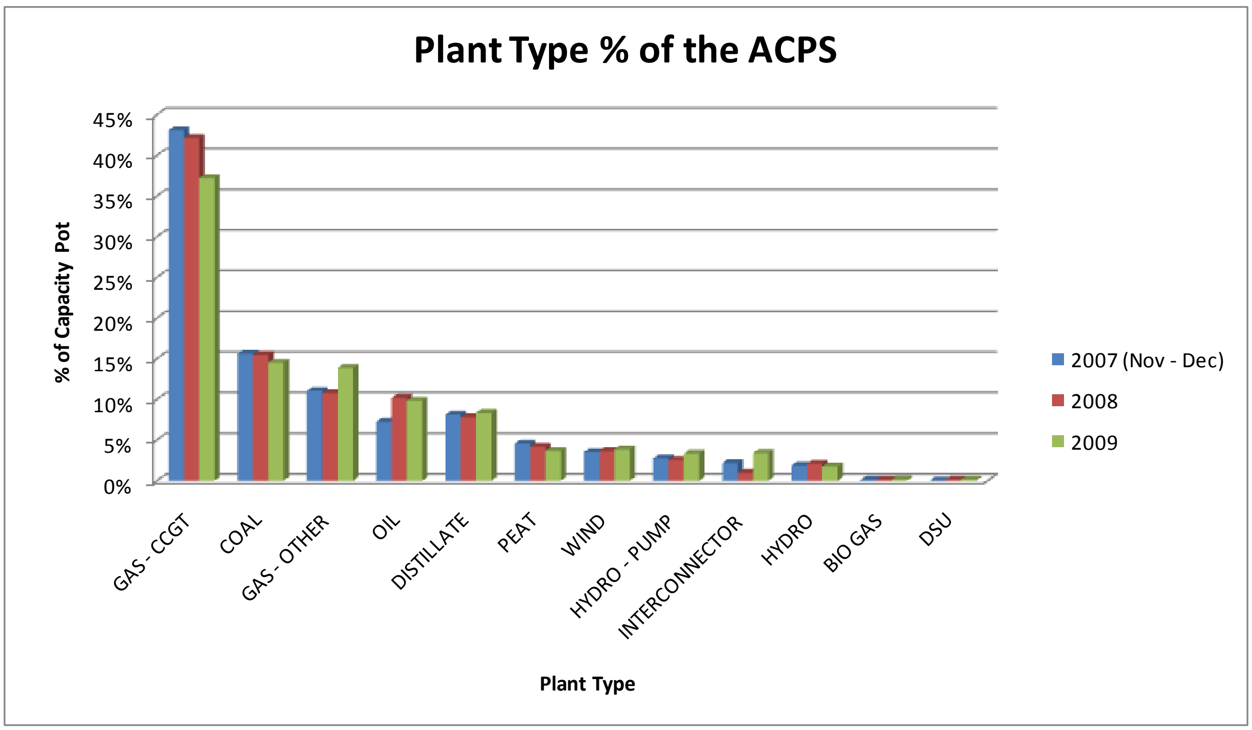


*Figure 3.0 – % Capacity Payment Distribution for Plant Types for 2007 (November & December) to 2009*

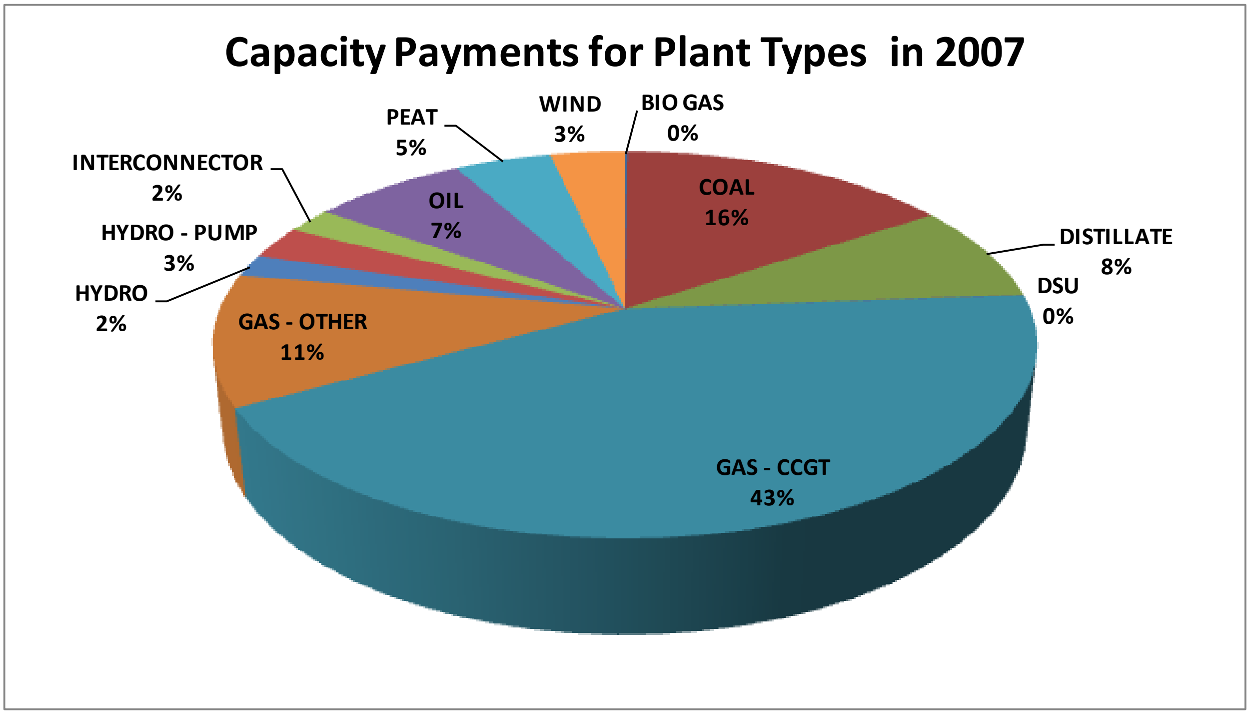


*Figure 3.1 – Capacity Payment Distribution for Plant Types for 2007 (November & December)*

The pie charts above show the distribution of payments among generator types for each year of the CPM. Gas plants have earned over 50% of the Capacity Payments, with CCGT plants receiving over 40% of payments.

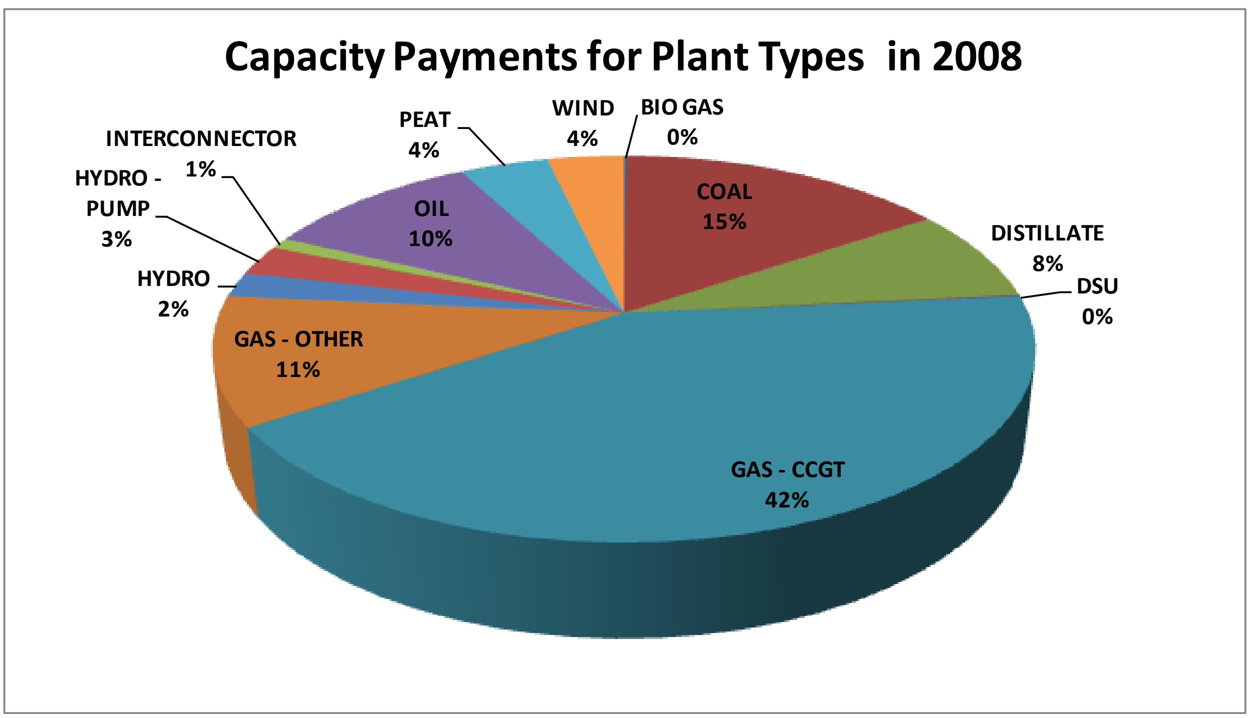


*Figure 3.2 – Capacity Payment Distribution for Plant Types for 2008*

It is worth nothing that the capacity payments made to Interconnector users reduced in 2008. This is due to the large amount of exports to Great Britain that occurred in the second half of 2008.

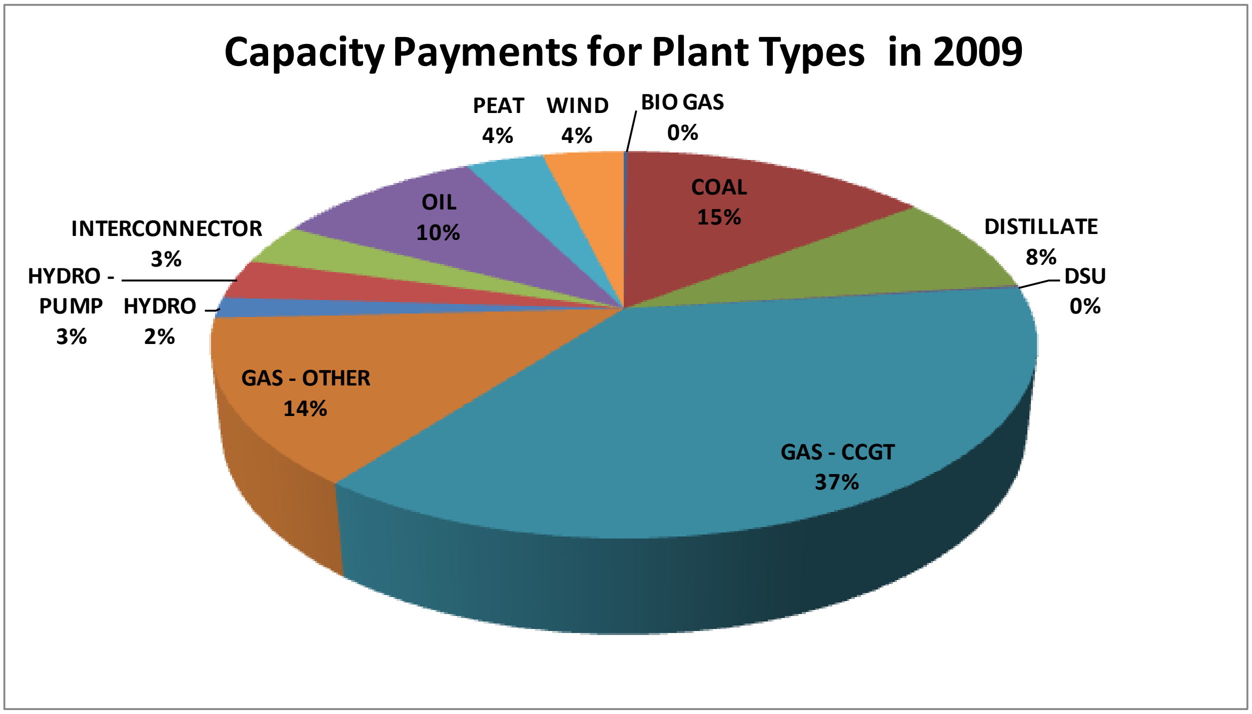


*Figure 3.3 – Capacity Payment Distribution for Plant Types for 2009*

### 3.1.2 DISTRIBUTION OF PAYMENTS BASED ON MARKET PARTICIPANT

The Pie Charts above shows the distribution of payments among generator types for each year of the CPM.

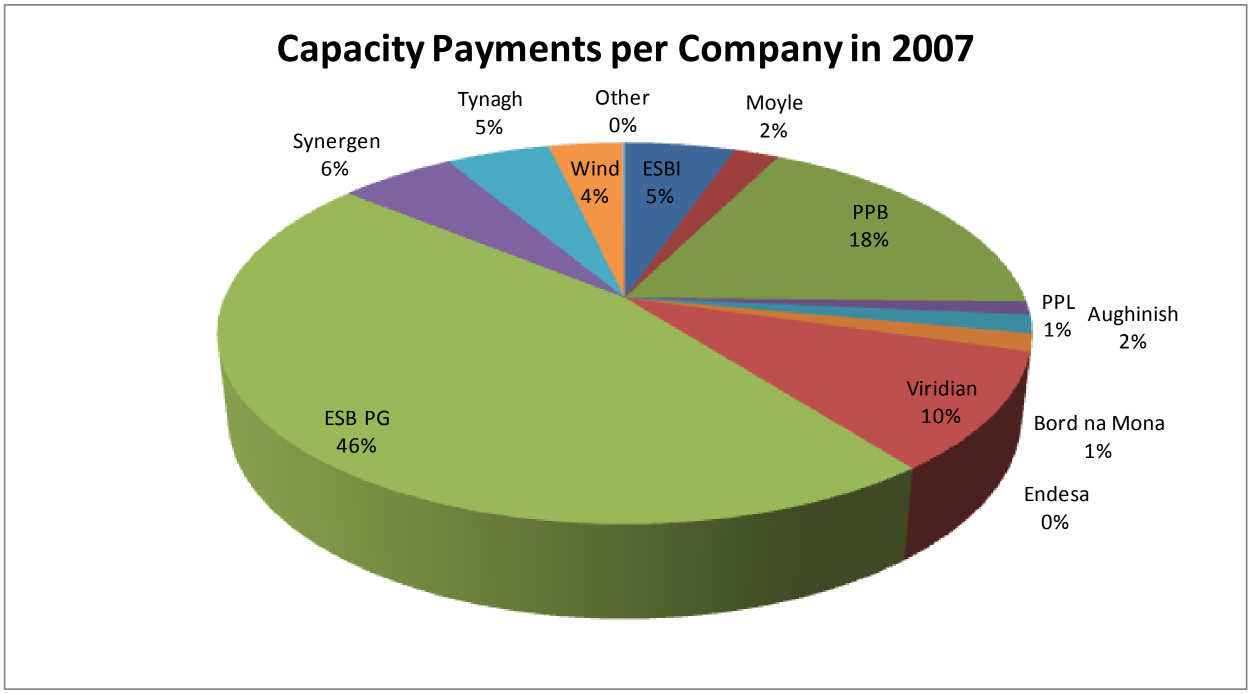


*Figure 3.4 – Capacity Payment Distribution for Market Participants for 2007 (November & December)*

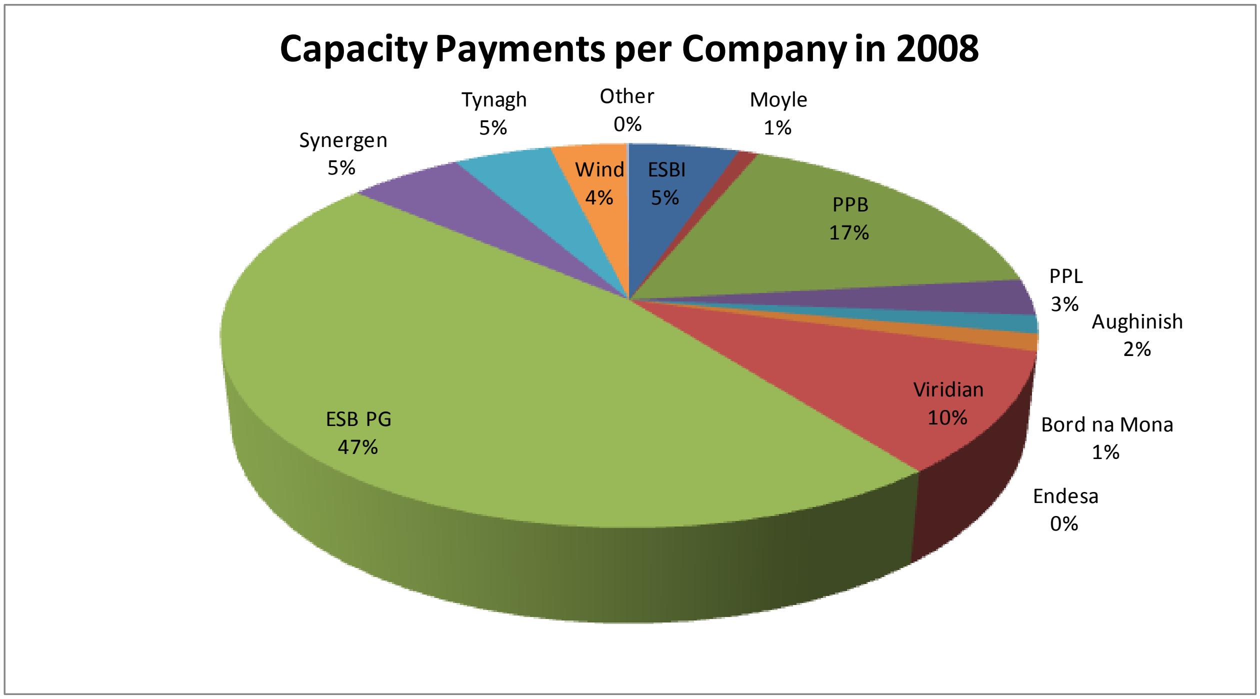


*Figure 3.5 – Capacity Payment Distribution for Market Participants for 2008*

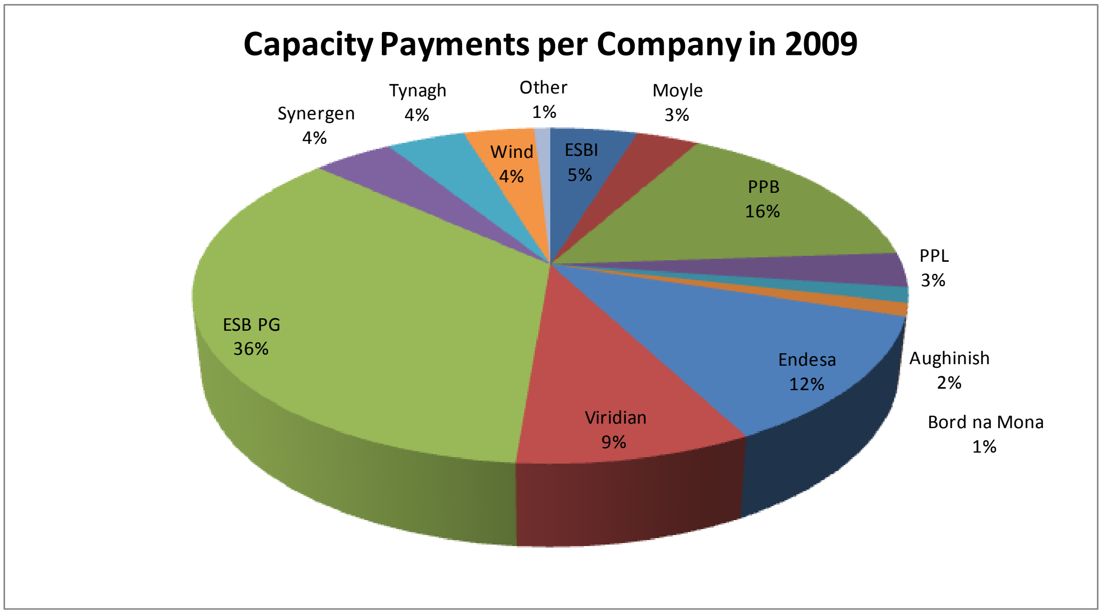


*Figure 3.6 – Capacity Payment Distribution for Market Participants for 2009*

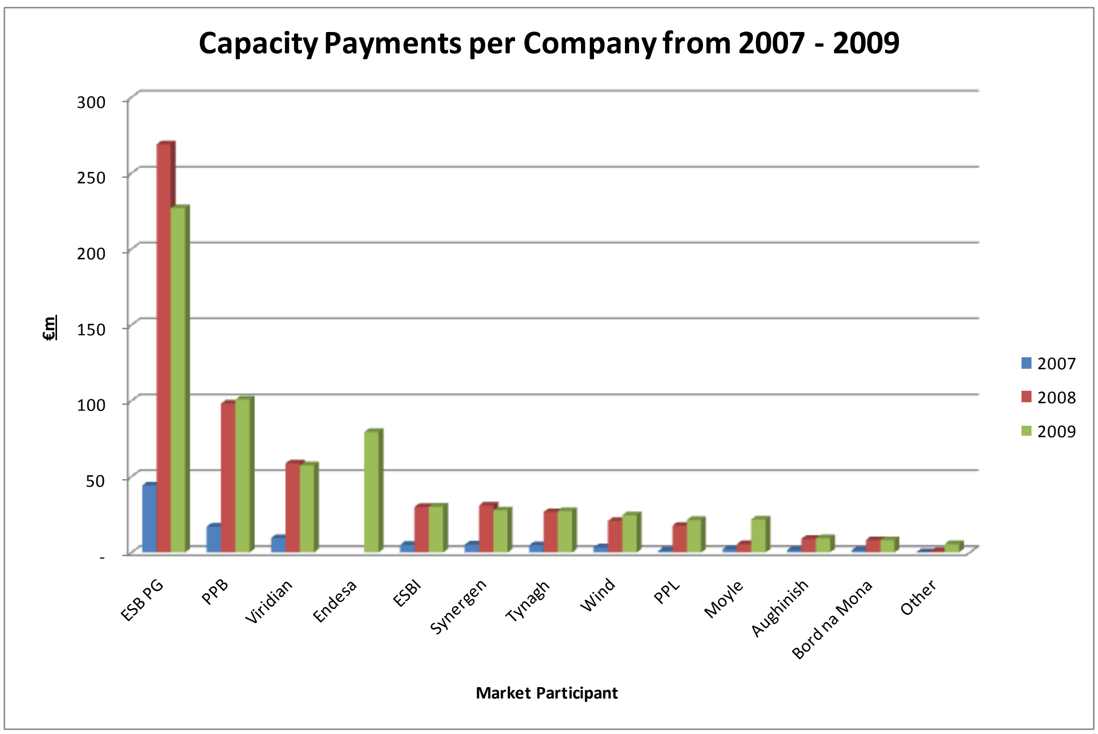


*Figure 3.7 – Capacity Payment for Market Participants from 2007 to 2009*

As the pie charts show the distribution of capacity payments remains relatively constant across 2007 and 2008. The significant change occurs in 2009 with the introduction of Endesa into the market following their purchase of plant from ESB PG. As a result of this, the proportion of capacity payments allocated to ESB PG reduces from 47% to 36% while Endesa received 12% in 2009.

### 3.1.3 DISTRIBUTION OF PAYMENTS VS MARGIN

An analysis of the data available for 2009 (January to June) was carried out to compare the distribution of capacity payments and margin. The graphs below show the average payments made and the average margin as a daily profile for each month (i.e. the Jan period is broken down into the average daily 48 half hour periods from 00:00 to 23:30 etc.)

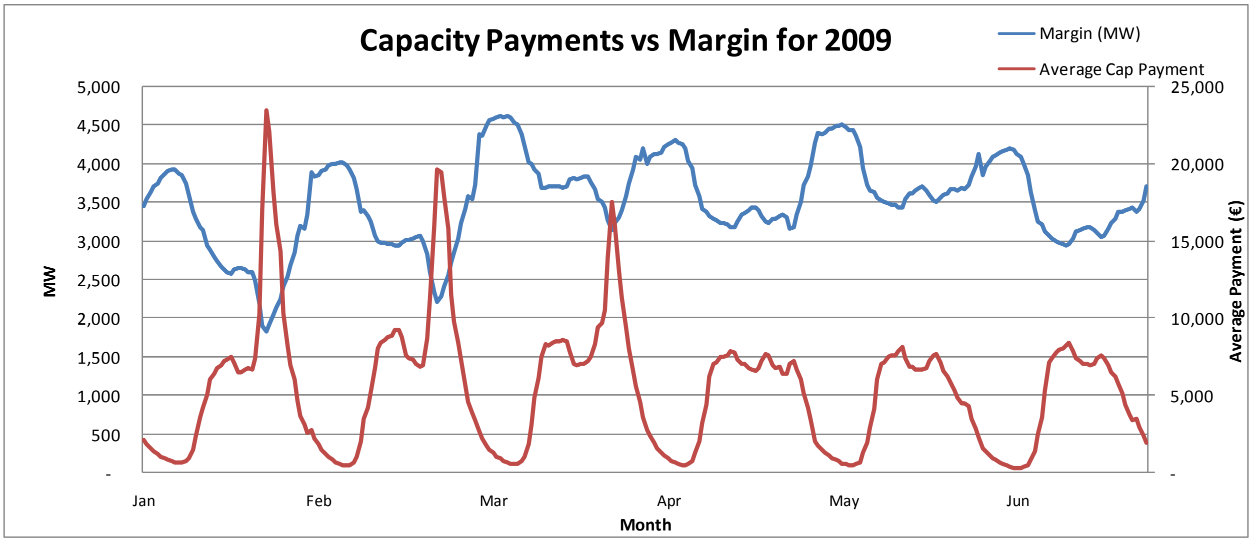


*Figure 3.8 –Distribution of Capacity Payments vs. System Margin for 2009 (January to June)*

Overall it can be seen from the graph that the capacity payments are highest when the margin is the lowest which generally aligns with the Objective of the Capacity Payment Mechanism relating to efficient pricing signals. The chart with a capacity payment in a €/MWh figure will show a similar chart profile. The change in the shape of capacity payments in Q2/09 when compared to Q1/09 coincides with the changes in temperature which impacts the demand shape.

The next three graphs show the margin against each of the 3 capacity factors that make up the full capacity payments (fixed, variable and ex-post).

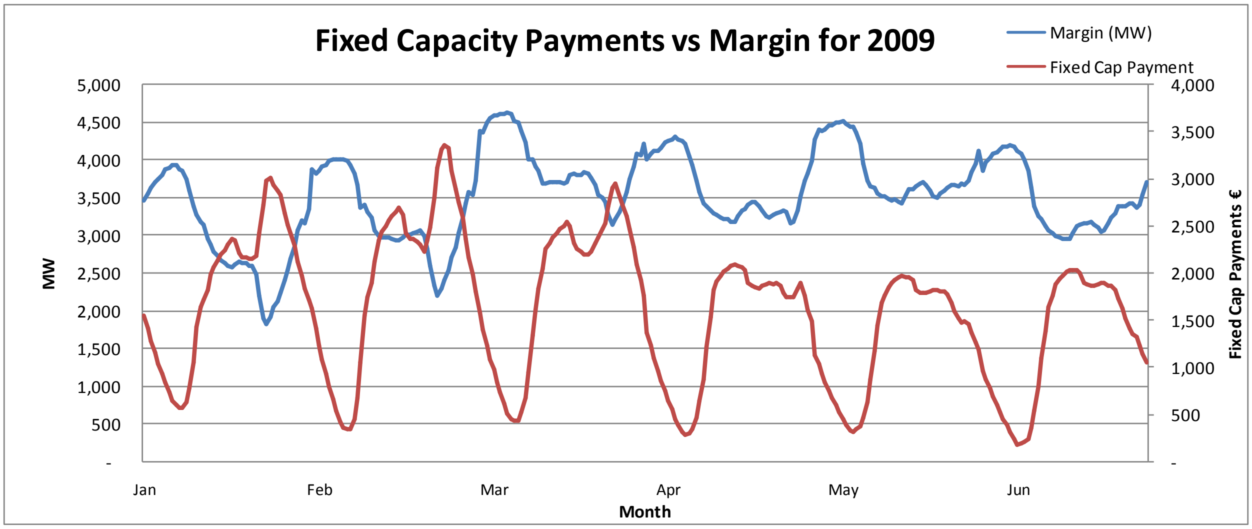


*Figure 3.9 –Distribution of Fixed Capacity Payments vs System Margin for 2009 (January to June)*

The fixed payments are determined year ahead and in general follow the expected pattern where the majority of fixed payments are available during periods of lower margin. However it should be noted that in the periods of high margin (hours 1am to 7am), the fixed capacity payments are proportionally higher in this period than those payments available during the day. This is discussed further in Section 3.1.4 below.

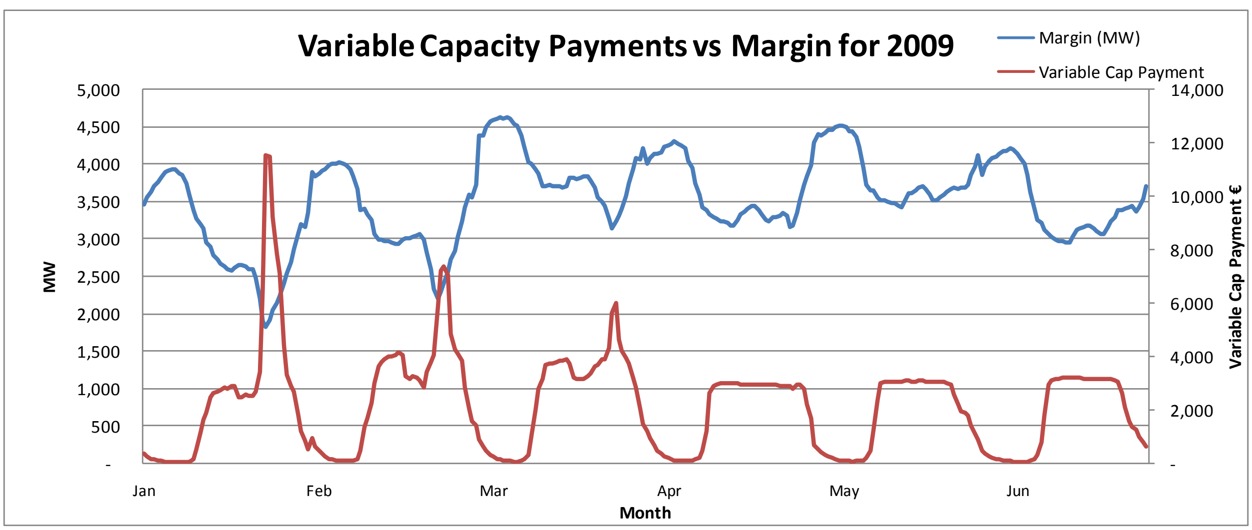


*Figure 3.10 –Distribution of Variable Capacity Payments vs. System Margin for 2009 (January to June)*

The graph in figure 3.9 shows the variable capacity payment against margin. The variable capacity payments are determined one month ahead. The variable payments reflect the expected trend where the capacity payments are highest during periods of lowest margin. It is worth noting the plateau type payments that occur during Q2/09. As the margin is higher and the overall margin is more uniform across the day, the capacity payments reflect this.

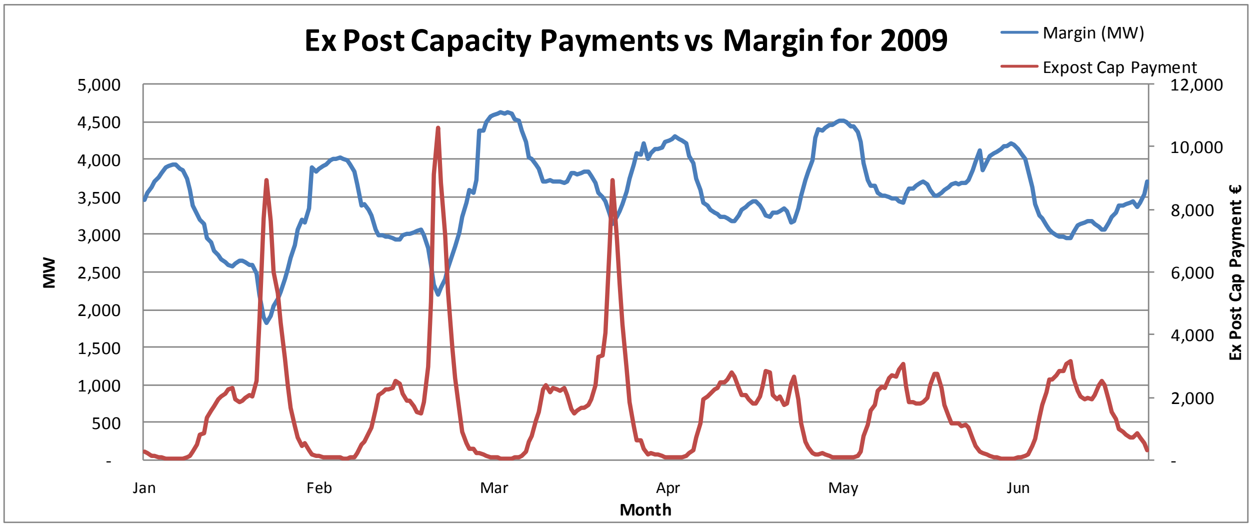


*Figure 3.11 –Distribution of Ex Post Capacity Payments vs. System Margin for 2009 (January to June)*

The graph in figure 3.10 shows the ex post capacity payments against margin. As expected, the relationship between capacity payments and margin shows the strongest correlation, as the ex post payments are based on actual outturn margin.

### 3.1.4 TIME OF DAY DISTRIBUTION OF PAYMENTS

The following graphs show the average distribution of payments based on time of day for the first and second quarter of 2009. As highlighted above, the variable and ex post elements broadly follow the mirror image of the margin curve. However, the fixed element has a flatter profile and has a significantly higher payment than the variable and ex post elements during the night (1am – 7am), when the margin is at its highest. The main difference in the profiles is the change in the variable element which is relatively constant throughout the day. The CPM Payment Factors follow the dip in the profile of the daily average margin. In Q1 the margin dips in the peak period in the afternoon which the average variable and ex-post payments respond to. In Q2 the margin profile dips early in the day and is sustained for a longer period which changes the CPM Payment factors profile when compared to Q1.

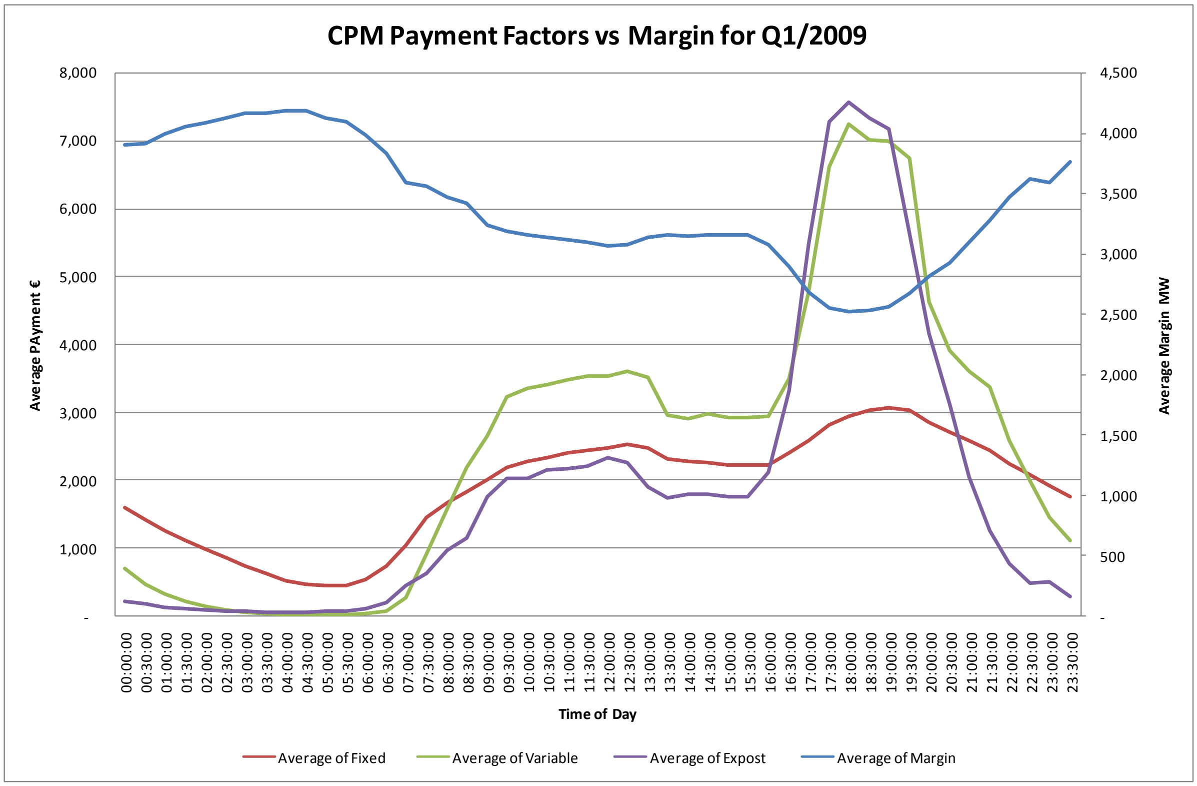


*Figure 3.12 – Time of Day Distribution for Market Participants for Q1/2009*

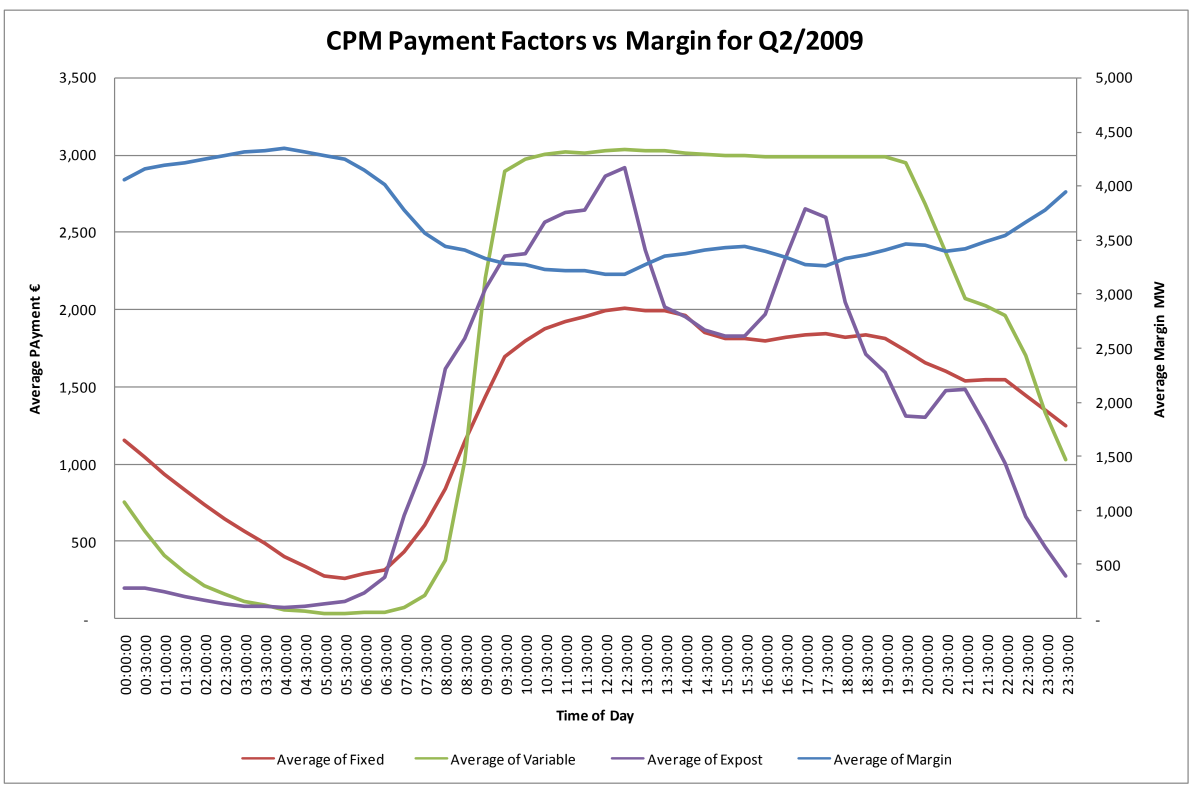


*Figure 3.14 – Time of Day Distribution for Market Participants for Q2/2009*

# 4 WORK PACKAGE 2 - REVIEW OF CAPACITY REQUIREMENT

As detailed in information paper SEM-09-105, the following outputs are expected from Work Package 2:

- Improving the transparency of the calculation process;
- Access to the Inputs used in the Capacity Requirement Calculation;
- Forced Outage Probability;
- Treatment of Wind and the Wind Capacity Credit used;
- Running of the Adcal Model;

## 4.1 TRANSPARENCY OF CAPACITY REQUIREMENT CALCULATION

Over the previous calculations of the Annual Capacity Payment Sum (ACPS), market participants requested additional transparency to be provided in relation to the calculation of the Capacity Requirement. The RAs have noted these comments and acted on them by holding a public forum on 18 November 2009[7] where the RAs and TSOs presented on the inputs and methodology used in the calculation. A demonstration of the Adcal model was also provided.

In addition, the RAs also published the inputs used for the 2010 Capacity Requirement Calculations[8] to further assist in the transparency of the calculation. A number of queries were raised at the public forum on 18 November on the inputs. As a response to these queries, it is the intention of the RAs to publish the inputs used for the 2011 Capacity Requirement calculation. A full description of the inputs used for the 2011 Capacity Requirement calculation has been included with the consultation paper on the ACPS for 2011. This consultation has take place in Q2/2010. These inputs will be included in the Appendix of the Capacity Requirement decision papers going forward.

In addition, the process used by the TSOs in calculating the Capacity Requirement is detailed in Appendix 1 of this paper.

## 4.2 FORCED OUTAGE PROBABILITY

The Forced Outage Probability (FOP) used in the calculation was defined as 4.23% in the paper 'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism Decisions Paper (SEM-07-13[9]). This was based on the weighted average FOP for NI plant for the period 2002 to 2006.

It was recognised that this FOP was lower than the average FOP on an All Island basis, however the RAs highlighted that reflecting the poor performance of plant in the determination of the Capacity Requirement will effectively

[7] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=ba1ce3a7-23ff-4dd3-8a88-cd715106eeaa&mode=author

[8] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=795ba106-becd-4355-99e9-febe9b45f63d

[9] http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=5f59436b-d753-498c-8ddd-013ad40aba00

provide compensation to units which perform poorly. One of the objectives of the CPM is to provide an incentive for improvements in plant availability and the RAs believe that by establishing the Capacity Requirement against a target FOP value, generators will be provided with an incentive to improve their performance toward the target level.

It should be noted that the above rationale still applies and the RAs have seen a significant improvement in the outturn FOP values since the start of the SEM, as demonstrated in the graphs below:

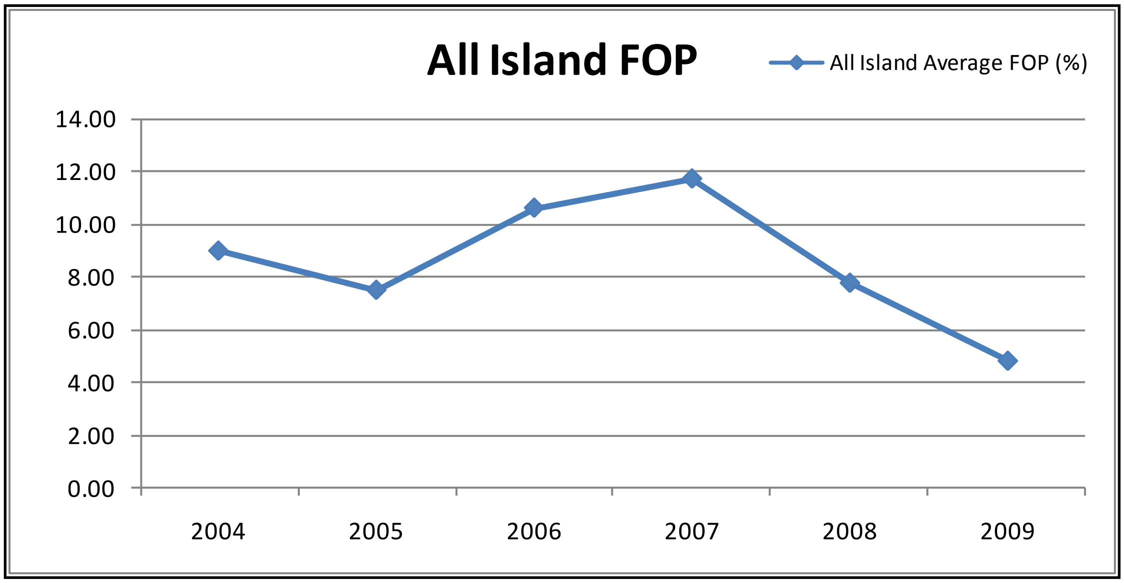


*Figure 4.1- RA Analysis - 5 year FOP Average.*

Eirgrid also calculate a FOP for the Republic of Ireland. This Generation System Forced Outage Rate is calculated on a 52-week rolling basis and is calculated as the sum of the weekly forced outage rates for the previous 52 weeks divided by 52. The weekly forced outage rate for each week is calculated as the sum of the forced outages experienced by the centrally dispatched generation units during that week divided by the total installed capacity of the centrally dispatched generation units.

The graph below is from the EirGrid website[10] and show the FOPs for the Republic of Ireland.

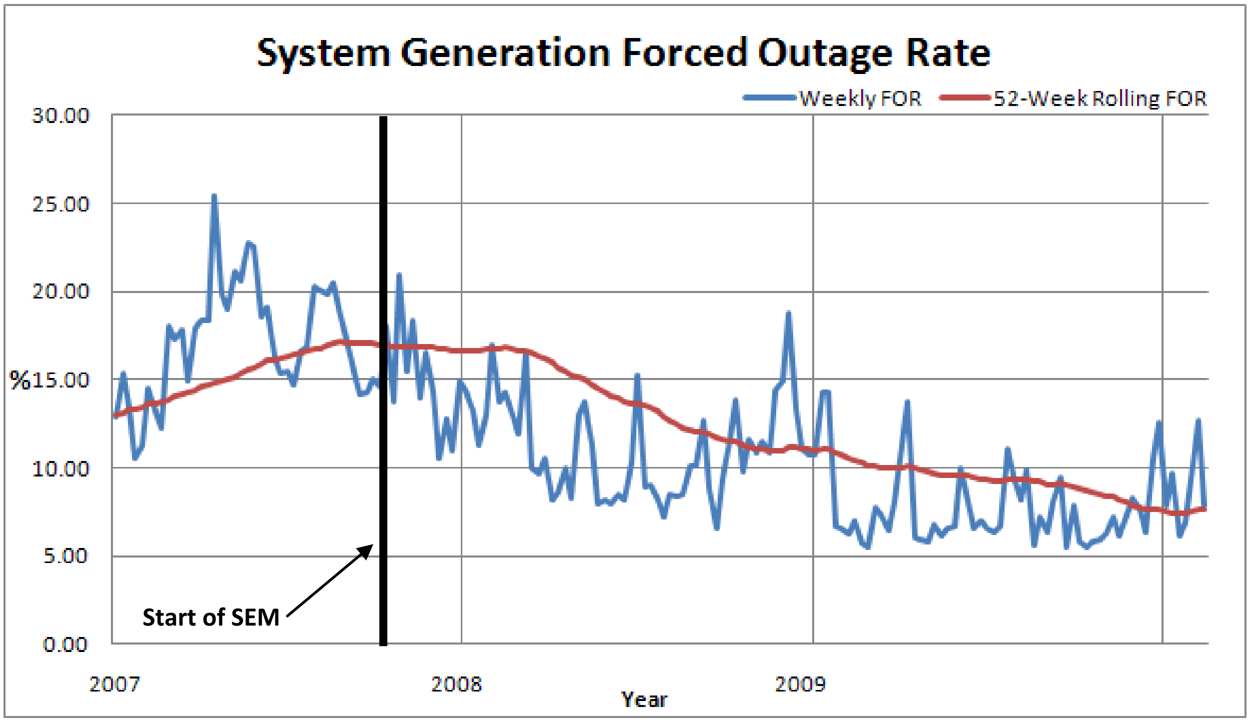


*Figure 4.2- Eirgrid System Generation Forced Outage Rate*

## 4.3 MARGIN IMPLIED IN CAPACITY REQUIREMENT CALCULATION

An area related to the FOPs discussion above is the level of margin the Capacity Requirement (CR) has over system peak demand. Concerns have been raised where the Capacity Requirement results in a margin of less than 5% over peak demand.

The RAs would like to reiterate the purpose of the Capacity Requirement Calculation is to determine the amount of capacity required to meet the Generation Adequacy setting of 8 hours loss of load per annum. This means that the Adcal model seeks to intentionally not serve exactly 8 hours of demand per annum.

In reality, the System Operators seek to serve all demand at all hours of the year and take active steps to minimise the chance that load on the system will need to be shed. This distinction notwithstanding, the SEM Committee is interested in the problem relating to the 'unconstrained' basis upon which the CR is calculated. Because the SEM is based on this unconstrained principle, it means that if the installed capacity on the island were to become exactly equal to the CR, then it would be expected that more than 8 hours of load may be shed due to the impact of transmission constraints.

[10] http://www.eirgrid.com/operations/systemperformancedata/generationsystemperformance/

## 4.4 IMPACT OF WIND ON THE CAPACITY REQUIREMENT CALCULATION

Another area the RAs investigated with the TSOs was the impact of wind on the Capacity Requirement Calculation. Currently the process includes the removal of the wind forecast from the demand trace in order to determine the capacity requirement to be met by the conventional plant. However, the RAs wanted to understand the impact of a 'high wind' scenario on the calculation.

Using the 2010 inputs, the RAs altered the wind forecast used to reflect a network with 6,000MW of wind. The TSOs ran the Adcal model for these scenarios to determine the impact.

Using the load profile for the 2010 cap requirement, the wind profile was modified to produce two scenarios;

1) Load Profile @ 6GW Wind – this profile has the same total load in 2010, but with increased wind by a factor of 3 to simulate 6GW of wind.

2) Load Profile @ 6GW Wind +high wind in peak day - this profile is similar to the file 'Load Profile @ 6GW Wind', but with increased the wind for the top c.200 periods of demand, thus reducing the conventional requirement. This is to determine what happens if there is high wind on the peak days in the year.

| Year | 2009 | 2010 | 2010 High Wind 1 (6GW) | 2010 High Wind 2 (Tailored Wind) |
|---|---|---|---|---|
| Cap Requirement | 7,356 | 6,826 | 6,585 | 6,503 |
| Diff from 2009 (% Drop) | 0% | 7.21% | 10.48% | 11.60% |

*Table 5.1 – Results from the Adcal model with High Wind Scenarios in 2010*

The high wind scenario and high wind peak periods produced a calculation less that 4.4 % of the Capacity Requirement that was calculated for 2010. The results from this modelling showed that in the case where the wind profile was modified to be high during certain peak hours, the change in the capacity requirement was not significant. This is due to the manner in which the LOLE is calculated. The LOLE is affected by the margin at each hour, not just demand. This means that peak demand hours do not necessarily dominate the total LOLE, but rather the hours of lowest margin.

## 4.5 SUMMARY OF ANALYSIS OF WORK PACKAGE 2 - REVIEW OF CAPACITY REQUIREMENT

Overall the key points that have been considered in this section of the paper are:

- The RAs have improved the transparency of the Capacity Requirement Calculation by publishing the inputs used for the 2010 Calculations. The RAs also hosted a public forum on the Capacity Requirement Calculation Methodology. In addition, the RAs intend to publish the inputs used in future Annual Capacity Payment Sum calculations.

- The RAs have considered the FOP used for the Capacity Requirement Calculation. Consideration was provided using a number of options and the impact on the Capacity Requirement determined. As a result of this analysis, the RAs are minded to continue to use the FOP of 4.23% as defined in the paper

'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism Decisions Paper (SEM-07-13[11])'.

- The RAs assessed the impact of increasing levels of wind on the Capacity Requirement to ensure that the methodology was fully robust in a high wind network. The outcome of this analysis is that high wind impact does not significantly impact the change in the capacity requirement.

[11] http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=5f59436b-d753-498c-8ddd-013ad40aba00

# 5 WORK PACKAGE 3 - DEDUCTION OF IMR & AS & BNE PEAKER PLANT OPTIONS

On an annual basis, the RAs carry out an analysis to determine the fixed costs associated with building and operating a Best New Entrant peaking plant (BNE). These costs are then used as part of the calculation to determine the annual capacity pot. The methodology to be used was decided in the paper AIP/SEM/07/14[12], where the process for determining the BNE was described. This paper builds on the consultation paper AIP/SEM/124/06[13], where 3 options were considered. Option 2 (the BNE option) was the preferred methodology selected.

## 5.1 THEORY OF THE CPM

Section 3 in the paper AIP/SEM/124/06 summarises the requirement for a CPM as follows:

*'…in practice many electricity markets have found that a pure energy price alone is insufficient to ensure generation adequacy owing to issues surrounding price volatility (generally resulting in the energy market being unable to realise a true value of lost load (VOLL)), generation uncertainty and capital market imperfections. Consequently many electricity trading systems have adopted a mechanism which allows generators to recover at least a proportion of their costs via an alternative payment mechanism – a capacity payment mechanism (CPM)…..'*

It should be noted that a key point in the selected design of the CPM within the broader theory of remunerating generators in the SEM is to consider the circumstance in which the market is at equilibrium.

At equilibrium, the peaker will set the marginal price (whenever it is scheduled) as it has the highest variable costs. Also within this system:

- There must be some hours with non-served energy and a marginal price equal to VOLL, since otherwise the system cannot be in equilibrium;
- Not all peakers will be equal or will have bought the fuel at the same price, therefore there will be some differences in their bids and some of them will be slightly infra-marginal;
- The peaker will earn Ancillary Services.

It should be noted that the above theory is based on a market at equilibrium and this is the basis that the CPM was introduced to the SEM. In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours Loss of Load Expectation per annum.

Based on this analysis at equilibrium and using the Generation Security Standard of 8 hours loss of load the system will intentionally lose 8 hours of load. During this these 8 hours the price will go to Market Price Cap (PCAP) and all the plants that are available, including the BNE Peaker, will have to opportunity to earn the PCAP.

The following analysis will look at implementation of CPM in the SEM and the impact of IMR deduction and propose an alternative view of IMR calculation at equilibrium.

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[12] http://www.allislandproject.org/GetAttachment.aspx?id=b131a78d-911c-4f42-9170-7803b5dcf661

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

## 5.2 IMPLEMENTATION OF CPM IN THE SEM & IMPACT OF IMR DEDUCTION

The Annual 'Capacity Pot' for the SEM is the product of 2 elements:

- The Annualised cost for a Best New Entrant Peaker (€/kW); and
- The Capacity Requirement to meet a GSS of 8 hours (MW)

The calculation of the Annualised cost for a Best New Entrant Peaker follows the following high level process:

1. Assessment of Technology Types available ('Long list');
2. Selection Criteria used to determine 'Short List' of options (e.g. size of plant, flexibility, etc);
3. Screening analysis is carried out to determine most cost effective option;
4. If required, the efficiency of the plant can be considered;
5. Once the plant is selected, the AS is calculated and deducted;
6. Once the plant is selected, the IMR is calculated and deducted;

The RAs have deducted the IMR from the BNE fixed costs, using the following justification (as detailed in AIP/SEM/07/14[14]).

*'… The RAs have indicated that, in the assessment of the costs of a BNE peaking plant, an expectation of profits from the energy and ancillary service markets that such plant will reasonably expect to earn will be deducted from the fixed cost of a BNE peaking plant. The BNE peaking plant will expect to earn infra marginal rent from operation in the energy market. …*

*… If a CPM was based on the capital costs of a BNE peaking plant without taking into account infra marginal rent earned in the energy and ancillary service markets, over compensation would occur as the CPM would be based upon the fixed cost of a peaking plant that primarily provided only reserve and was wholly compensated for that provision only by the CPM. In reality compensation is very likely to also occur through activity in the energy market and the ancillary service market, if this is not taken into account; the CPM will over compensate all generators…. '*

Upon review of the CPM and the large number of participant responses on this issue over the past three years, the SEM Committee considers that this approach may be contrary to the theory explored in the previous section and has serious implications to the stability of the annual pots, as will be shown below.

A key priority for the BNE Investor is the level of risk associated to the remuneration of his investment. A volatile IMR depending on the many circumstances that happen in system operation will result in the generators receiving an unstable and unpredictable income every year. This goes against the objectives of the CPM of volatility and Price stability.

The current process for calculating the BNE fixed costs could be argued to be lacking a step; in that the technology would not be chosen without considering the IMR that is enjoyed by each option. The level of infra-marginal rent is particularly sensitive to the tightness of the capacity margin (as demonstrated in the energy market), leading to the perverse case that the Capacity Pot (ACPS) is likely to fall in years where new capacity is needed (i.e. the tighter supply margin is, and the more new capacity is needed; therefore the BNE will earn higher infra-marginal rent and a lower capacity pot will result).

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

Taking the 2010 calculations for demonstration purposes, the plant and fuel type was selected purely using the fixed costs as shown in the Table 5.1, in keeping with the established practice:

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Total Annual Cost | 19,006 | 17,047 | 17,338 | 16,269 |
| Capacity (MW) | 193.6 | 190.1 | 193.6 | 190.1 |
| **Annualised Cost per kW** | 98.17 | 89.67 | 89.56 | 85.58 |
| **Rank** | 4 | 3 | 2 | 1 |

*Table 5.1 – Selection of BNE Peaker for 2010 based on fixed costs analysis.*

However, a rational investor could be argued to consider all costs and revenues prior to making a final decision, therefore the process could instead calculate the IMR and AS for all four options. This analysis has been carried out using the 2010 data. As can be seen, it has a very significant impact on the final annualised costs for the Gas (Dual Fuel) options.

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Total Annual Cost | 19,006 | 17,047 | 17,338 | 16,269 |
| Capacity (MW) | 193.6 | 190.1 | 193.6 | 190.1 |
| **Annualised Cost per kW** | 98.17 | 89.67 | 89.56 | 85.58 |

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Ancillary Services | 937 | 920 | 937 | 920 |
| Annualised Cost per kW | 4.84 | 4.84 | 4.84 | 4.84 |

*AS is same regardless of fuel type*

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Inframarginal Rent | 8,784 | 0 | 8,784 | 0 |
| BNE Cost per kW | 45.37 | 0.00 | 45.37 | 0.00 |

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Final BNE Cost per kW | 47.96 | 84.83 | 39.35 | 80.74 |
| **Rank** | 2 | 4 | 1 | 3 |

*Table 5.2 – Selection of BNE Peaker for 2010 based on all costs and revenue*

As can be seen, the Gas plant options (Dual Fuel) earn considerable IMR in 2010, due to the spread of fuel price assumptions in the Plexos model[15]. The deduction of IMR using this alternative process would have had a significant impact, reducing the 2010 pot from **€551.1M to €268.6M.**

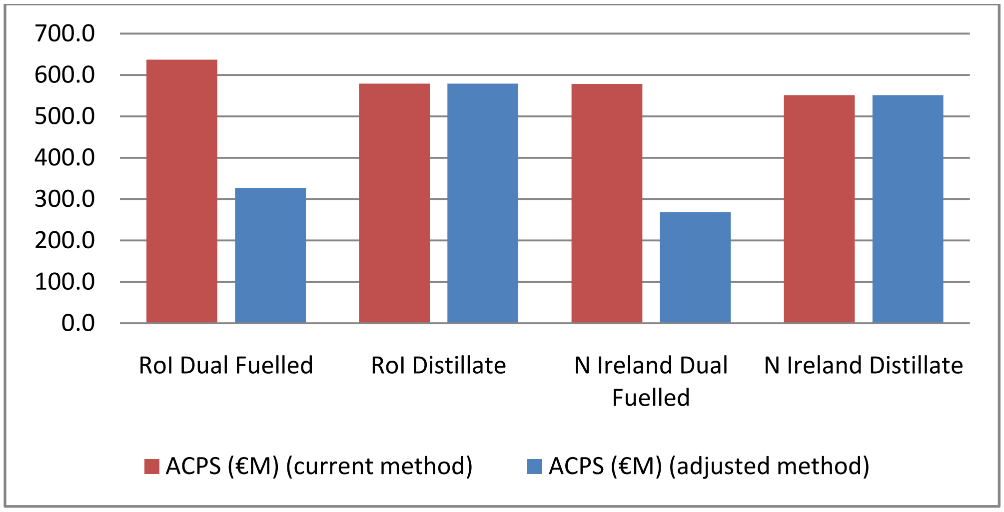



*Figure 5.1 – Current Method vs. Adjusted Method*

The implications of a change in estimated real IMR are thus significant and represent genuine volatility in the CPM calculations. The SEM Committee wishes to remove this level of volatility if possible. While one possibility would be to simply not deduct the IMR, it is the RA's view that **at equilibrium** the BNE Peaker **does** earn infra-marginal rent and this **should** be deducted from the Annualised Cost per kW of the BNE.

At equilibrium the 8 hours loss of load will come into effect. This is an Insufficient Capacity Event, and the Trading and Settlement Code states that SMP is set equal to Market Price Cap (PCAP) during these periods. A simulation of this is provided below in order to estimate the IMR that the peaker would earn during these 8 hours. The analysis assumes that a PCAP of €1,000/MWh will be in effect during the period, and that the Forced Outage Probabilities (FOP) would have an impact on the available plants; as there is a 4.23% chance that the BNE peaker will not be available during these 8 hours. It is also assumed that the 8 hours occur during periods in the year in which the peaker is not on a planned outage.

The RAs wish to consult on two possibilities to stabilise the volatility of IMR calculations in the CPM and a Status Quo option:

1. **IMR Deducted in €/kW = [VOLL – Bid Price of BNE] / 1000 x 8 hours**
2. **IMR Deducted in €/kW = [PCAP – Bid Price of BNE] /1000 x 8 hours**
3. **Status Quo**

A notional bid price of €100/MWh has been assumed for a distillate-fired plant in the following calculations.

[15] IMR calculations based on one Plexos run

| Item | Value | Abbreviation |
|---|---|---|
| VOLL | 10,390 | VOLL |
| Price Cap | 1,000 | PCAP |
| GSS Hours | 8 | Outage Time |
| BID Price of Peaker (€/MWh) | 100 | BID |
| BNE Capacity | 191 | BNECAP |

*Table 5.3 – 2010 Inputs to the IMR calculation*

**Option 1 – Using VOLL**

IMR Deducted in €/kW = [VOLL-BID] / 1000 * Outage Time

Using the 2010 BNE calculation this equates to: [10,390-100]/1000*8 = 82.32

Revenue earned by the peaker during this period is "[VOLL-BID] * BNECAP * Outage Time" which is

[10,390-100]*191*8 = 15,723,120

**Option 2 – Using PCAP**

IMR Deducted in €/kW = [PCAP-BID] / 1000 * Outage Time

Using the 2010 BNE calculation this equates to: [1000-100]/1000*8 = 7.2

Revenue earned by the peaker during this period is "[PCAP-BID] * BNECAP * Outage Time" which is

[1,000-100]*191*8= 1,375,200

**Impact on the 2010 Calculation if Option 2 was used.**

| Cost Item | 2010 Decision | 2010 with PCAP IMR |
|---|---|---|
| Annualised Cost per kW | 85.58 | 85.58 |
| Ancillary Services | 4.84 | 4.84 |
| Inframarginal Rent | 0.00 | 7.20 |
| **BNE Cost per kW** | **80.74** | **73.54** |

*Table 5.4 – 2010 Decision with Option 2*

| ACPS | 2010 Decision | 2010 with PCAP IMR |
|---|---|---|
| BNE Cost per kW | 80.740 | 73.54 |
| Capacity Requirement | 6826 | 6826 |
| **ACPS** | **551.13** | **501.98** |

*Table 5.5 – ACPS 2010 Decision with Option 2*

From Table 5.4 and 5.5 it can be seen that the inclusion of Option 2 would have resulted in a reduction of 49.15m of the 2010 ACPS which is a -8.92 % variance.

If Option1 (VOLL) was used it would have resulted in an negative BNE cost per kW as shown in table 5.6

| Cost Item | 2010 Decision | 2010 with VOLL IMR |
|---|---|---|
| Annualised Cost per kW | 85.58 | 85.58 |
| Ancillary Services | 4.84 | 4.84 |
| Inframarginal Rent | 0.00 | 82.32 |
| **BNE Cost per kW** | **80.74** | **-1.58** |

*Table 5.6 – ACPS 2010 Decision with Option 1*

It is considered that the use of the PCAP would be more accurate because of the fact that a real plant operator would receive this price during insufficient capacity events, rather than VOLL.

**Option 3 - Status Quo option**

This is a Status Quo option in that the RAs continue to use the current approach to measure the IMR of the BNE peaker. This approach has been used in previous years (2007 to 2011). The approach used is to complete two Plexos runs, one with the BNE peaking plant and all its true characteristics and one without. A unit commitment schedule is derived for the BNE peaking plant from the first Plexos run and the actual infra marginal rent calculation is then derived using the original SMP estimations from the Plexos run without the BNE peaking plant included.

Twenty five full year half hourly simulations of the SEM in the model year are run, in which forced outage patterns are randomly generated from one iteration to the next to give a spread of system margin scenarios across the model year. The BNE plant is the observed to see if it is scheduled at all in any of the twenty five iterations. If it is not scheduled, it is assumed that there will be zero infra-marginal rent.

**Views are invited with regard to these effects / proposals.**

This method would heavily reduce the level of volatility and / or potential uncertainty currently in place regarding the IMR deduction. The key variables in the method are semi-fixed (VOLL, PCAP, GSS) and so the deduction should be able to be forecast by investors with reasonable accuracy. The only 'floating' variable is the bid price of the BNE unit, which will be driven by prevailing fuel prices (distillate in the case of a distillate-fired plant for example). However the impact of even significant movements in fuel price (such as doubling or halving) on the calculation is minimal.

The RAs also wish to consult on the impact that the FOP has on the above calculations. There is a 4.23% chance that the BNE will not be available during these 8 hours, so it is considered that this should factor in to the IMR calculation, (note that this % is probably less, since the BNE will take care to do its best to be available at the time of the year where it is more likely that there might be non served energy in the system). If the FOP is included in Option 2, then the IMR of €7.2/kW/yr would reduce to €6.9/kW/yr, resulting in a BNE Cost of €73.84/kW/yr with an ACPS of €504.03 million in 2010.

## 5.3 DEDUCTION OF ANCILLARY SERVICES PAYMENTS FROM THE BNE PEAKER CALCULATION

The deduction of ancillary payments is discussed in paper AIP/SEM/124/06[16] where the following rationale is provided.

*'The RAs have indicated that, in the assessment of the costs of a BNE peaking plant, an expectation of profits from the energy and ancillary service markets that such plant will reasonably expect to earn should be deducted from the fixed cost figure …. Similarly such plant would be expected to earn revenue in the ancillary service market, in particular in the provision of reserve. Therefore, basing a CPM on the capital costs of a BNE peaking plant alone will result in over compensating generators given that they would be fully compensated through the CPM and would also derive additional economic rent from the energy and ancillary service market.'*

The RAs acknowledge that not all plant types will receive Ancillary Services payments, however on discussions with the TSOs during the calculation of the BNE costs for 2010 it was indicated that a new Peaker plant would be highly likely to be awarded an ancillary services contract. As this is a revenue stream that is separate from the energy market (and capacity market), it is appropriate that this revenue stream should be considered for deduction from the BNE Peaker fixed costs. It should be noted that any expected income that the BNE could expect to receive should be deducted from the annual fixed cost to determine the CPM.

## 5.4 SUMMARY OF ANALYSIS OF WORK PACKAGE 3 - DEDUCTION OF IMR & AS & BNE PEAKER PLANT OPTIONS

This section of the paper has detailed the original theory relating to how the CPM fits in to the SEM. The section discussed how the SEM implementation has moved from the theory and the potential flaws in the current BNE calculation and recommends some options for calculating the IMR that the BNE earns at equilibrium.

- The RAs are minded to recommend that Ancillary Services payments be continued to be considered for deduction from the BNE Peaker fixed costs.
- The RAs welcome comments from participants in relation to the options 1 - 3 on the deduction of IMR.

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

# 6 WORK PACKAGE 4 - BNE PEAKER PLANT FUEL OPTIONS

This work package looks at the alternative technology types of plants in consideration for the BNE calculation and the fuel choice for the peaking plant. Regarding the Dual fuel options, the RAs highlighted in the consultation paper 'Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010' (SEM-09-072[17]) the following point:

*"The RAs note that a variety of short term capacity products from a variety of sources are available in the Republic of Ireland, and a range of short term products as required by EU directive 1775 are also available. However a similar range of products on an uninterruptible/firm basis are currently not available in Northern Ireland, but are planned for delivery under the Common Arrangements for Gas (CAG).*

*This inconsistency in the two jurisdictions does create an issue of equity in treatment of generators located in both jurisdictions that requires further consideration. Furthermore, the RAs wish to deliberate on this matter in a holistic manner taking into consideration issues such as the bidding principles and the energy market. "*

This section will review the Gas Capacity issue and will look at other types of plants in consideration for the BNE calculation.

## 6.1 GAS CAPACITY

In previous years, the RAs determined that the BNE peaking plant would run on distillate only. The decision was largely due to the costs associated with booking gas capacity and a perceived lack of liquidity in secondary gas capacity trading.

It was decided that for 2010, GTs under consideration would be evaluated both for distillate firing and for natural gas operation with dual-fuel capability. This decision was driven by a number of factors; including respondents views that further developments in the gas market meant gas was a credible fuel source. It was argued that there are a series of short and long-term products available in the RoI and interruptable products available in Northern Ireland. An assumption therefore needs to be made on the approach that a rational investor would take to contracting for gas capacity.

As part of the European Union, Northern Ireland (NI) and the Republic of Ireland (RoI) are committed to the development of a Single European Gas Market. The European Commission has put in place an overarching legislative framework within which all member states are working to achieve the Single Gas Market which is designed to bring benefits to all European citizens and to contribute to Europe's competitiveness. A Memorandum of Understanding (MoU) between the two Regulators was published on 7th April 2008 on the development of the Common Arrangements in Gas (CAG) project, under the All Island Energy Market Development Framework.

At present however, there is no harmonisation of gas capacity products in NI and ROI. NI has a short term interruptible tariff while ROI has monthly, daily and within day firm products.

At the time of this writing the standing policy from the SEM Committee is that the cost of gas transportation capacity remains best interpreted as fixed. As stated above, the RAs are committed to working together to

[17] http://www.allislandproject.org/GetAttachment.aspx?id=78b20fef-dd75-43a7-8f52-67c7ca661545

establish Common Arrangements for Gas for NI and RoI. Part of such arrangements is expected to be the harmonisation of gas transmission capacity products.

## 6.2 OTHER TYPES OF PLANTS IN CONSIDERATION

This section will look at other types of plants in consideration for the BNE calculation. They are:

- Demand side Response;
- Aggregated Generator Units (AGU);
- Pumped storage Units;
- The Interconnector.

Each of these plant types will continue to be investigated in the BNE Calculation methodology.

### 6.2.1 DEMAND SIDE RESPONSE.

Demand Side Response (DSR) is achieved when power users reduce a portion of their electricity demand from the electricity network in response to a high price or some other event such as an overload.

The SEM Committee understands that demand response has the potential to be an important element of the all-island market, delivering economic and environmental benefits. An active and effective demand response on the island of Ireland will require high level coordination between the many different stakeholders involved in the electricity sector and industry.

The RAs will continue to treat these Demand side units the same as generation within the BNE Calculation. The Demand Side Response programme is in its infancy and will continue to develop over the next few years; therefore the CPM team will liaise closely with this work area to ensure that impacts on the CPM are fully considered.

### 6.2.2 AGGREGATED GENERATOR UNITS (AGU)

Aggregated generator Units (AGUs) are units which combine smaller more geographically dispersed generation technologies, they comprise of numerous small-capacity, distribution-embedded diesel generators operating in export mode.

The SEM Committee have noted that the:

*"Aggregated Generator means a collection of Generators each with a capacity of no greater than 10MW, and each of which are either:*

*a) on Generation Sites covered by more than one Connection Agreement; or*

*b) where one or more of those Generator Sites which does not have a Connection Agreement and are not located on Contiguous Sites; and which are defined as an Aggregated Generating Unit under the Grid Code"* [18]

[18] SEM Committee Decision for the Regulatory Authorities to Approve Mod_05_08 (Recommendation Report FRR_05_08)

AGUs will be considered at this stage as prototype technology but similar to the Demand Side Response, AGUs are still in their infancy on the island and there is simply not enough on the Island.

At this time the there is not enough market evidence to support an AGU as the BNE. The unit must meet the Grid Code and minimum functional specifications for the BNE calculation in order to be considered. Further testing is required from the central dispatch systems, as this is still a prototype technology, to see if there is a realisable mechanism of dispatching large scale AGU generation. As the number of AGUs develops and becomes more robust the AGU peaker will continue to be investigated and considered in the BNE Calculation methodology. For the 2011 BNE calculation, the RAs propose that an AGU should not be used as the appropriate BNE peaker. While the technology appears to be establishing and controllable under the desired requirements for a peaking plant, it was noted that the existing level of installed capacity is low, and it would be almost impossible to theoretically serve a sizable proportion of SEM demand with this technology. This is an important point because technologies which have a 'carrying capacity' could distort the signals sent by the CPM if used as the BNE peaker.

To illustrate by example, consider a situation where a peaking technology with very low fixed costs became available to investors, but could only be constructed up to a maximum of 50MW on the island. It would be possible then, at equilibrium, for the last MW of demand to be served by the *second* best peaking technology, one which could be built to an arbitrarily high capacity; in which case it would be more appropriate to set the Annual Capacity Payment Sum based on the annualised fixed costs of the second-best new entrant.

### 6.2.3 PUMPED STORAGE

The SEM Committee is encouraged by a continued interested investment parties in the future development of Pumped Hydro Energy Storage (PHES) and Compressed Air Energy Storage (CAES) plants on the island. Pumped storage units potentially offer a number of advantages to the system, namely;

- Reduced wind curtailment,
- Serving peaks in demand,
- High ramp rates,
- Lower cost provision of primary and secondary operating reserve.

The Capacity Payments Mechanism does not currently put a value on these advantages to the system and in light of this it is highly unlikely that Pumped Storage would be the BNE. From discussions with potential investors and specialist consultants, to date it appears that the site topography and suitability play a significant role in the costs (there are only a limited number of potential suitable sites for PHES or CAES), resulting in a large variation of plant sites with the total capital costs coming in between the central to high estimates The outcome of these discussions indicate that the total capital costs of pumped storage as peaking plant are coming in between the central to high estimate figures, this would be much too high for the Best New Entrant calculation process.

### 6.2.4 INTERCONNECTOR

The SEM Committee are encouraged that significant progress has been made on the East-West interconnector as this is consistent with the drive of European policy towards the development of regional and more integrated electricity markets.

The RAs have also considered the Interconnector as a potential candidate for the BNE calculation and have deemed it as unsuitable as there is a level of uncertainty as to whether the Interconnector would definitely be able to supply the last MW of load in all situations. This is because of the potential correlation between system stress on the island and system stress on the other side of the interconnector. An example of such a stress happen on the 14/10/2008 there was a period of low margin within the SEM the average margin had fallen to below 1500MW, with the average SMP being €106 and ELEXON being €96, the interconnector was still exporting an average flow of 8.67MW.

## 6.3 SUMMARY OF ANALYSIS OF WORK PACKAGE 4 - BNE PEAKER PLANT FUEL OPTIONS

Having taken the above information into consideration the RAs have concluded that:

- Until the delivery of the Common Arrangements for Gas (CAG), there will be inconsistency in the two jurisdictions, with uninterruptible/firm basis products are currently not available Northern Ireland. There are still large costs associated with booking gas capacity and a perceived lack of an all island gas market liquidity. The RAs will continue drive the development of the CAG to ensure that gas is a credible fuel source under fuel security considerations on the island as a whole.
- AGUs and DSR units are still in their infancy on the island but will continue to be investigated in the BNE Calculation methodology.
- In a future with, at certain times, high availability of generation from renewable sources, it will be important for demand to be able to flex freely to use this inexpensive and low carbon electricity when it is available.

# 7 SCOPE OF WORK FOR WORK PACKAGE 5 - EXCHANGE RATE FOR CPM

As detailed in information paper SEM-09-105, the following outputs are expected from Work Package 5.

The Single Electricity Market (SEM) was the first of its kind in the European Union and is a flagship development in the European drive and vision for regional electricity markets, the combining of two smaller markets into one, produced an efficient and cost effective cross jurisdictional market.

The SEM is truly cross-jurisdictional, developed by the two Regulators, supported and guided by the two Ministers and their Departments and facilitated by the two System Operators and the Single Electricity Market Operator. In this context the RAs do not believe in market segmentation which would result in separate RoI and NI capacity pots (and therefore jurisdictional pots).

The RAs intend to look at the impact the fixed annual exchange rate has had on CPM payments and the options available to reduce any impact that exchange rate fluctuation may have on participants. In order to carry this activity out, the RAs analysed the CPM market data for 2008 and 2009.

## 7.1 SUMMARY OF THE ANNUAL CAPACITY EXCHANGE RATE

Currently the SEM Trading and Settlement Code (the Code) specifies that the Market Operator shall make a report to the RAs at least four months before the start of the Year and in advance of the first Capacity Period in each Year, proposing a value for the following parameter for that Year: the "Annual Capacity Exchange Rate" (ACERy). The Euro to Pound exchange rate is fixed using this value for the year.

In September each year SEMO produces a report that addresses the values that should apply for the Annual Capacity Exchange Rate. The exchange rate recommended is based upon the average SEM Bank forecast. The rates from 2008 to 2010 are shown in Table 7.1 below.

| Year | Euro/GBP Annual Capacity Exchange Rate |
|---|---|
| 2008 | 0.6851 |
| 2009 | 0.7944 |
| 2010 | 0.8586 |

*Table 7.1- Euro/GBP Annual Capacity Exchange Rate from 2008 to 2010*

The derivation of the currency exchange rate used is provided below by the SEM Bank: Danske Bank:

"The most suitable gauge for predicting future exchange rates is to use the current market forward FX rates for the period in question. The current market rate is the collective bargaining of the market to reach this (spot) price and the forward points are determined by the markets forecast for interest rates, relative to the period involved.

Forecasts are less suitable as they are the view of one person or organisation. The forward FX rate is simply the rate at which one currency can be exchanged for another currency, at any given date in the future, as at/agreed today. It is calculated using the current spot FX rate (current market price for delivery in 2 business days), and then adding or subtracting any relevant forward points that may apply to that rate.

Forward points are a measure of the difference in the underlying interest rates for both currencies, expressed as a proportion of the underlying exchange rate price. Forward points are used to account for any benefit/disadvantage from the difference in these underlying interest rates (e.g. EUR interest rates are less than comparative GBP interest rates, and so there is an advantage from holding GBP until the maturity of the forward contract.)

Generally the spot rate is far more volatile than the forward points, and as such is the key driver/ determinant of the overall forward rate. "

## 7.2 HISTORICAL ANNUAL CAPACITY EXCHANGE RATE.

In response to the Medium Term Review consultation paper (SEM-09-035) a number of respondents proposed that the impact of fluctuations in the exchange rate could be reduced by setting the Capacity Exchange rate on a monthly basis rather than an annual basis. Any alternatives must be considered on how it will affect the objectives of the CPM;

- Simplicity – will it be predictable and simple to administrate;
- Price Stability – will it increase volatility in the market;
- Fairness – does it give greater certainty to generators and eliminates competitive and jurisdictional distortions;
- Efficient price signals for long term investment – does it provide efficient signals to appropriate market entry and exit.

For the purpose of the historical analysis and looking at the exchange rate at a monthly level, the RAs obtained from the MMU database[19] an average of the Daily Trading Day Exchange Rate for the year, see Table 7.2 for the Ex Post Average Daily Trading Day Exchange Rate for 2008, 2009 and 2010 (First 5 Months) and the Variance from the Actual Annual Capacity Exchange Rate (ACER).

| | 2008 | 2009 | 2010 |
|---|---|---|---|
| **Annual Capacity Exchange Rate** | 0.6851 | 0.7944 | 0.8586 |
| **Average of Daily Trading Day Exchange Rate for the Year** | 0.7956 | 0.8918 | 0.8785 |
| **Variance** | -0.1105 | -0.0974 | -0.0199 |

*Table 7.2- Annual Capacity Exchange Rate and Average Daily Trading Day Exchange Rate for 2008, 2009 and 2010 (First 5 Months of 2010)*

[19] This database is updated with Daily Info from SEMO Daily Publications- http://www.sem-o.com/market_publications/Daily_Publications/

The RAs also extracted from the MMU database an average of the Daily Trading Day Exchange Rate for each Month:

| Year | Month | Average of Daily Trading Day Exchange Rate for each Month | Variance Between Months | % Variance Between Months |
|---|---|---|---|---|
| 2008 | Jan | 0.7471 | -0.0246 | -3.2865% |
| | Feb | 0.7511 | -0.0040 | -0.5350% |
| | Mar | 0.7735 | -0.0224 | -2.8940% |
| | Apr | 0.7942 | -0.0207 | -2.6118% |
| | May | 0.7914 | 0.0028 | 0.3559% |
| | Jun | 0.7910 | 0.0004 | 0.0501% |
| | Jul | 0.7934 | -0.0023 | -0.2952% |
| | Aug | 0.7918 | 0.0015 | 0.1956% |
| | Sep | 0.7997 | -0.0079 | -0.9845% |
| | Oct | 0.7880 | 0.0117 | 1.4813% |
| | Nov | 0.8245 | -0.0365 | -4.4311% |
| | Dec | 0.9010 | -0.0764 | -8.4824% |
| 2009 | Jan | 0.9236 | -0.0226 | -2.4489% |
| | Feb | 0.8861 | 0.0375 | 4.2315% |
| | Mar | 0.9158 | -0.0297 | -3.2411% |
| | Apr | 0.9011 | 0.0147 | 1.6280% |
| | May | 0.8866 | 0.0145 | 1.6392% |
| | Jun | 0.8587 | 0.0278 | 3.2429% |
| | Jul | 0.8605 | -0.0018 | -0.2069% |
| | Aug | 0.8608 | -0.0003 | -0.0389% |
| | Sep | 0.8893 | -0.0285 | -3.1994% |
| | Oct | 0.9164 | -0.0271 | -2.9583% |
| | Nov | 0.8976 | 0.0188 | 2.0937% |
| | Dec | 0.9006 | -0.0030 | -0.3345% |
| 2010 | Jan | 0.8845 | 0.0161 | 1.8232% |
| | Feb | 0.8749 | 0.0096 | 1.0962% |
| | Mar | 0.9017 | -0.0268 | -2.9743% |
| | Apr | 0.8841 | 0.0176 | 1.9941% |
| | May | 0.8606 | 0.0235 | 2.7355% |

*Table 7.3- Average Daily Trading Day Exchange Rate for each Month in 2008, 2009, 2010 and the Variance and % Variance between Months.*

The variance from one month to the next can be seen across the period in Figure 7.1.

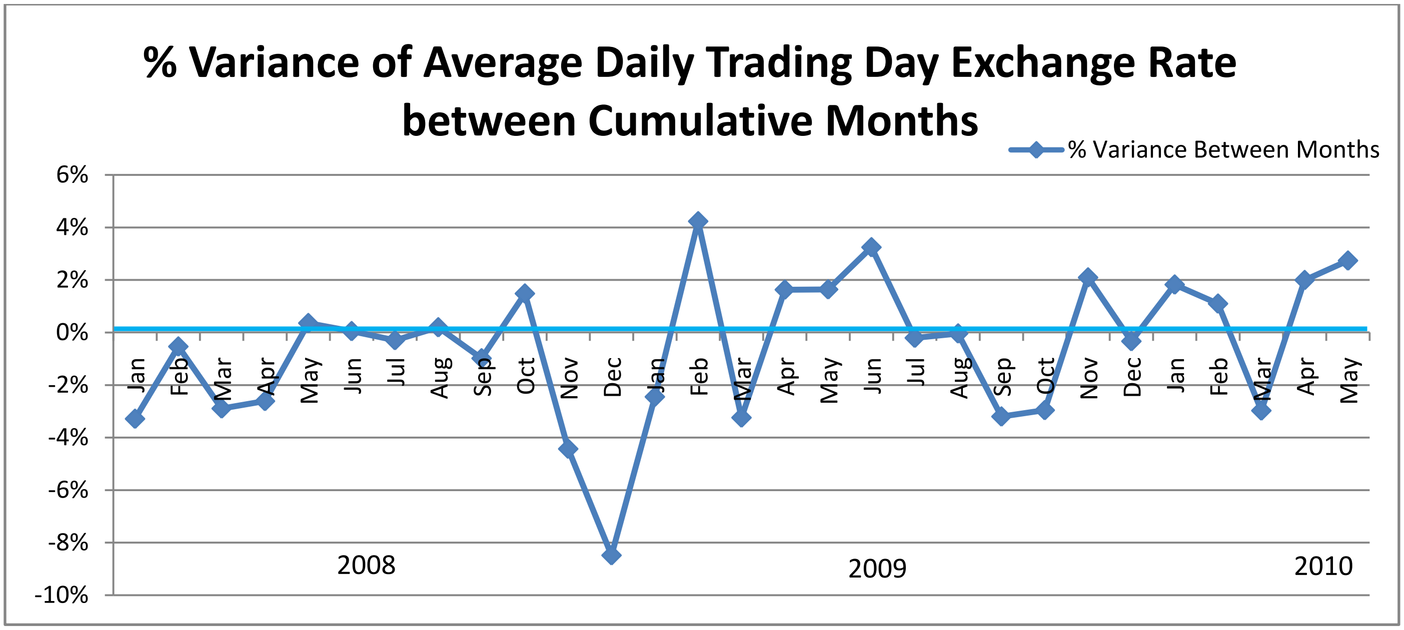



*Figure 7.1- % Variance of Average Daily Trading Day Exchange Rate between Cumulative Months*

It can be seen from Figure 7.1 that there was a degree of volatility in Q4 2008 and Q1 2009. This shows that during this period the exchange rate variable represented a stepped change over time, decreasing month on month in Q4 2008 and increasing in the start of Q1 2009 before decreasing again in March 2009. This type of volatility makes it very difficult to predictable and to administrate.

In Appendix 2 the RAs have included Table 7.4 (Northern Ireland Share of the Capacity Pot by ACER and by an Ex-Post Monthly Daily Exchange Rate) where they applied the Average of Daily Trading Day Exchange Rate for each Month to the % share of NI demand (€) x Monthly Exchange rate (£) for 2008 and 2009. The Average Daily Trading Day Exchange Rate for each Month is obtained Ex-post from the MMU after the month had ended.

In 2008 the NI breakdown had a 27.09% share of the Capacity Pot and in 2009 that share had risen to 28.8% (and 29.6% in the first 5 months of 2010). In each monthly instance the monthly Daily Exchange Rate has been greater than the ACER (which was set 4 months prior to the period year starting), this would have resulted in a monthly average increase of £1.5m over the 2 years. The Northern Ireland Generators would have received roughly £17m extra a year if an Ex-post Monthly Exchange rate was implied to the 2008 and 2009 payments. This is likely to be largely offset by the increase in the exchange rate value of the capacity charges that the suppliers would have been charged if they were using the monthly exchange rate. In 2010 the Monthly Average Exchange rate has fallen more in line with the ACER, the monthly Daily Exchange Rate would have resulted in a monthly average increase of £0.3m over the first 5 months of 2010.

In setting a monthly pot various methods of alternatives will have to be investigated to determine what method of forecasting would best predict the future rate. Will the Monthly Exchange rate be Ex-Ante? - What the exchange rate will be a month from now, or even a week from now, is often very difficult to predict. The larger the magnitude of the exchange rate change, or the more quickly it changes over time, the more volatile it is. Will the Monthly Exchange rate be Ex-Post? – Will the monthly exchange rate be calculated from an Average of Daily Trading Day Exchange Rate for previous Month and provide a forecast for the rest of the year?

If the exchange rate was moved to a monthly rate, this will have implications to the market operator in terms of complexity and administration. Floating monthly rates may add a significant cost to the market in the form of greater uncertainty about exchange rates than most expected, volatile exchange rates make investment decisions more difficult because volatility increases exchange rate risk (the potential to lose money because of a change in the exchange rate), and thus may have an impact on future long term investment.

## 7.3 CONCLUSIONS FROM THE HISTORICAL ANALYSIS

Although high volatility has been apparent in the currency exchange markets, it has also been the result of fairly extreme economic and world circumstances. However the RAs are of the opinion that all methodologies have their draw backs and benefits.

Exchange rate movements do have an impact on prices paid by Northern Ireland consumers. A monthly methodology means that Northern Ireland generators / suppliers must deal with fluctuating exchange rates on a month to month basis. From using the Ex Post Monthly Daily Exchange Rate the NI generators would have benefited for this rate being higher than the ACER but in other economic circumstances it could have been a disadvantage. It should also be noted that the NI Customer is protected in that they pay less when the exchange rate goes against the NI generators.

The annual fixing of the exchange rate provides greater certainty to generators and eliminates competitive and jurisdictional distortions. With the increasing difficulty of attracting investment in the current uncertain economic climate, the emphasis should be on providing a stable regulatory environment. The setting of the exchange rate on an annual basis offers a long term view consistent with the principles of capacity pot predictability and ease of calculation within the market operator.

The RAs acknowledge that there will always be some element of risk associated with currency exchange rates. The exchange rate risk is an everyday risk managed and hedged by both generators and suppliers operating in a cross-jurisdictional market. The use of a fixed annual exchange rate is a balance between the sharing of risks in the currency exchange between generators and suppliers in Northern Ireland and the higher volatility that would be associated with more frequent adjustments in the exchange rate.

## 7.4 SUMMARY OF ANALYSIS OF WORK PACKAGE 5 - EXCHANGE RATE FOR CPM

- The RAs are minded that an exchange rate will be fixed annually for each tariff year/period using the market forward exchange rates. As this best facilitates the objectives of the CPM.
- The RAs do not agree with market segmentation which would result in separate RoI and NI jurisdictional capacity pots.
- The RAs want to ensure that there are no sudden shocks to the CPM and that the outcomes of the CPM review give investors greater revenue visibility .

# 8 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 31 August 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.

# 9 APPENDIX 1 – PROCESS USED FOR CAPACITY REQUIREMENT CALCULATION BY THE TSO

## 1 INTRODUCTION

This document details the methodology for calculation of the Capacity Requirement (CR) for the Capacity Payment Mechanism (CPM). The CR is the volume element of the Annual Capacity Payment Sum (ACPS). Guidance on the methodology and the key decisions taken by the Regulatory Authorities (RAs) in respect of the determination of the Capacity Requirement for the CPM can be obtained from the AIP paper "*Methodology for the Determination of the Capacity Requirement – Decision Document*" which can be obtained from the AIP website.

## 2 OUTLINE

The basic approach for the determination of the Capacity Requirement is based on a generation adequacy assessment using the AdCal programme. This programme builds a load model and a generation model and calculates the Loss of Load Expectation (LOLE). This LOLE is compared with the applicable adequacy standard and adjustments are made in the event of a surplus or deficit in order to establish the quantity of capacity required to exactly meet the selected adequacy standard. The approach adopted is that the determination of capacity requirement should not reflect the constraint between NI and ROI and to date a single generation adequacy standard of 8 hours/year is applied.

Separate demand forecasts for ROI and NI are prepared by the Transmission System Operators (TSOs) and these are aggregated into a single forecast for the All Island system. The demand excludes that supplied by generators not participating in the market. The demand met by generators not participating in the market is associated with small scale generators (SSGs) and constitutes a small component of total demand. These generators and the demand supplied from them are excluded from the model.

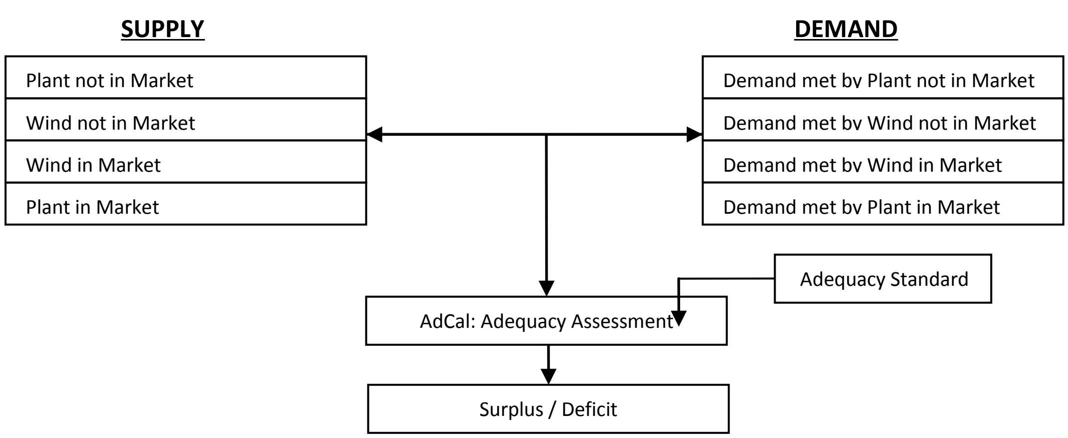



**Figure 1**

Total system adequacy as determined in the annual Generation Adequacy Statement considers the total generation and demand on the system (Figure 1) whereas the Capacity Requirement is based on the adequacy calculations pertaining to only the generation participating in the market. Following the adequacy calculations the Total Capacity Requirement is derived.

The calculations use time weighted capacities for plant (wind and non wind) to account for decommissioning or commissioning of plant within a year. For wind plant in the market, using this adjusted total, a capacity credit is computed. Finally, the surplus / deficit is restated as a new amount in terms of Reference Plant. The process is illustrated in Figure 2 and more detail follows on how each model is prepared and analysed.

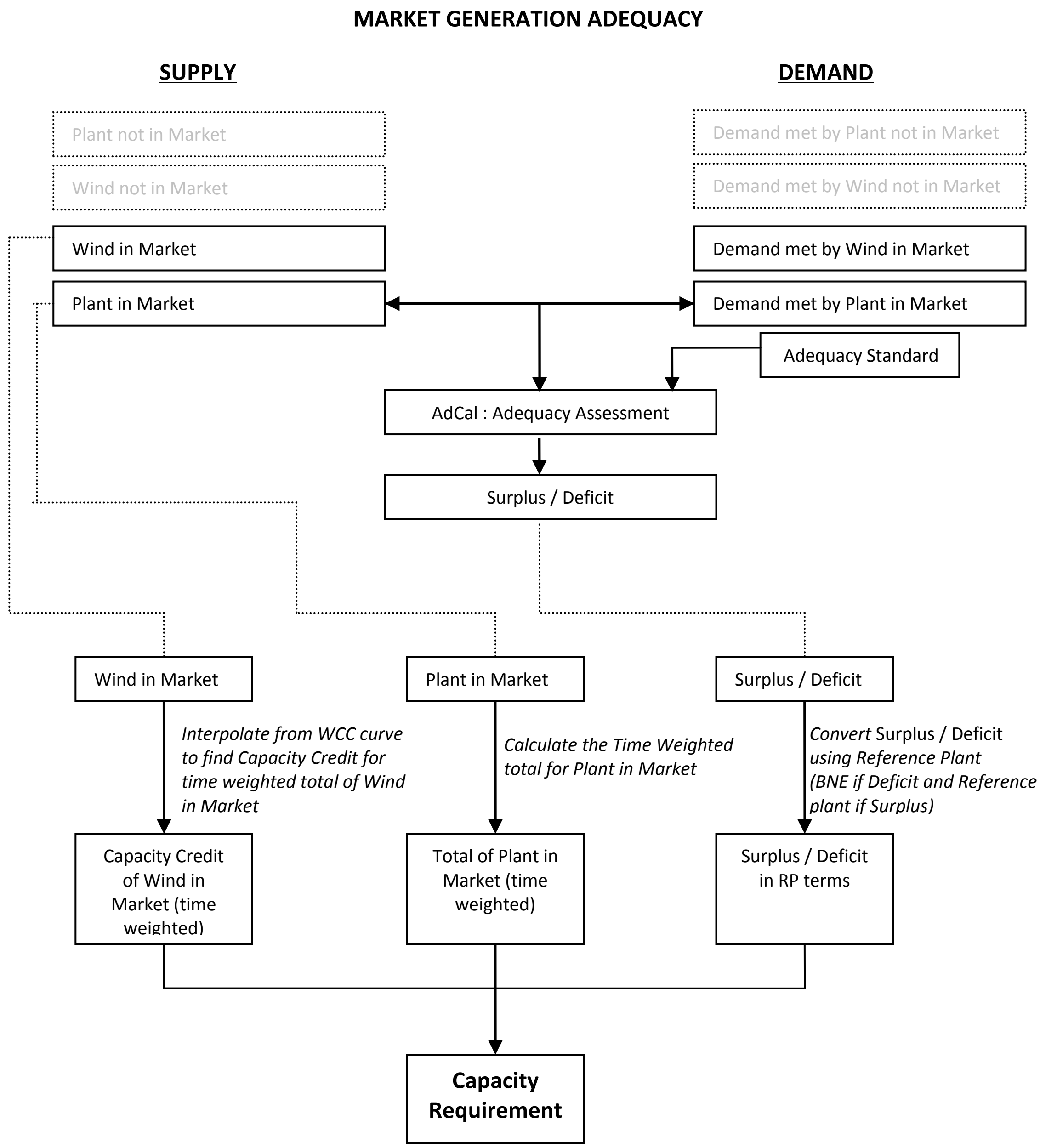



**Figure 2**

The inherently variable nature of wind power makes it necessary to analyse its adequacy impact differently from that of other generation units. The contribution of wind power to generation adequacy is referred to as the capacity credit of wind. This capacity credit has been determined by subtracting a forecast of wind's half hourly generated output from the customer electricity demand curve. The use of this lower demand curve (net of wind output) results in an improved adequacy position. The amount of Perfect Plant (see below for description of Perfect Plant) which leaves the system with the same improvement in adequacy as the net load curve, is taken to be the capacity credit of wind. In calculating the generation adequacy with AdCal all forecasted wind generation and demand is removed from consideration.

## 2 DEMAND

The basis of the Demand Forecast is the latest Generation System Adequacy forecast in each jurisdiction. The RAs selects the appropriate demand scenarios to be used. The forecasts are prepared by reference to a single historical year. For conformity, the same year is selected for both systems. For All Island Demand the profiles of demand for NI and ROI are added together.

As mentioned above the demand met by generation not participating in the market (associated with SSGs) is not included in this model. The quantity and plant type for SSG units is required so that the TSOs can estimate the energy and peak demand supplied by such plant. In addition, wind is treated separately when calculating adequacy and a forecast of the demand supplied by wind is also subtracted from the demand.

The demand profile prior to the removal of wind is used to allow AdCal to schedule the timing of the maintenance outages. The forecast wind is not netted off the demand for this purpose as any such forecast is unpredictable and use of such a demand forecast net of Wind (which is used for the purposes of deriving the extent of surplus/deficit) could result in distortions in the outage schedule.

The demand forecasts to be used should be the most recent forecasts prepared by the TSOs in relation to the Generation Adequacy Reports produced for NI and RoI. Precise timing may need further discussion between the RAs and the TSOs. The Trading and Settlement Code requires the RAs to consider and determine the value of Annual Capacity Payment Sum four months prior to the start of the Year to which it applies and then to make this value available to the Market Operator. This timing needs to be considered when determining the demand forecast data to be utilised.

## 3 GENERATION DATA

CAPACITIES

The model requires the capacities, forced outage probabilities (FOP) and scheduled outages for all generation that is participating in the market. The RAs initially wrote to each generator requesting the provision of unit capacities. However, for more recent calculations, the information used was sourced from the market data and validated against the TSO data. This data is provided by the RAs to the TSOs as the Market Participant Plant.

FORCED OUTAGE PROBABILITIES

The Capacity Requirement is evaluated using a target FOP value (4.23%) to provide an incentive for generators to improve their performance so as to capture more of the CPM payments. The principle is that a weighted average FOP for the past five years from generation plant in NI will be used for all generation plant in All Island. The Moyle Interconnector is not included in this calculation as it is not a generator unit and its inclusion would distort the data. FOP data for Moyle is provided by SONI.

SCHEDULED OUTAGES

Outage durations will be based on a historic average duration over a five year period. The TSOs provide historic scheduled outage data to the RAs. Year on year, this is likely to merely be an update for the year that has just passed as previous data will obviously still apply. The RAs will then determine the Scheduled Outage Durations (SODs) for the units comprised in the market participation for the model. For units with less than five years history data from similar units will be selected.

To account for the fact that the AdCal software requires SODs to be defined in integer weeks, the RAs developed a method of minimal deviation by fuel type. The RAs will continue to be responsible for the provision of SOD model input data (based on historic data provided by the TSOs).

The AdCal software is used to establish the outage schedule each year. This schedule is saved and used in all the subsequent studies. However, certain plants need to have their outages manually constrained:

- Such plants are those entering or exiting the market where the periods of unavailability are treated as scheduled outages by AdCal.

- Hydro plant which could (because of their size) otherwise be scheduled to take outages in the Winter.

The TSOs will use their judgement as to how best to schedule these outages.

Note that a cut-off date is be determined by the RAs so as to define the data to be utilised for the determination of the Capacity Requirement. This date will also freeze data associated with expected Market participation. The RAs will be responsible for determining the date each year and both the RAs and the TSOs (with input from the Market Operator) will work to confirm the Generator Units to be considered in the determination of the Capacity requirement for the relevant year.

# 4 WIND DATA

## 4.1 CAPACITY and FORECAST GENERATION

The Total Wind Capacity Installed at the end of each year is taken from the latest Generation System Adequacy forecast in each jurisdiction. The forecast wind generation for all wind capacity is projected from the same historical year as for the system demand for ROI and NI separately. The summation of the two separate Wind forecasts leads to an All Island Wind Profile.

4.2 WIND CAPACITY CREDIT

The most recent available Wind Capacity Credit (WCC) curve is used to assess the total WCC for the combined total wind installed on both systems. The component of the Capacity Requirement associated with wind will pertain only to wind participating in the market. When totalling the market wind, it was decided that capacities should be time weighted (as for convention plant) to reflect their impact on adequacy. The Average WCC is calculated for the total installed wind. Then this average WCC is applied to the time weighted total capacity for the Wind in Market. See Figure 3 for an illustration.

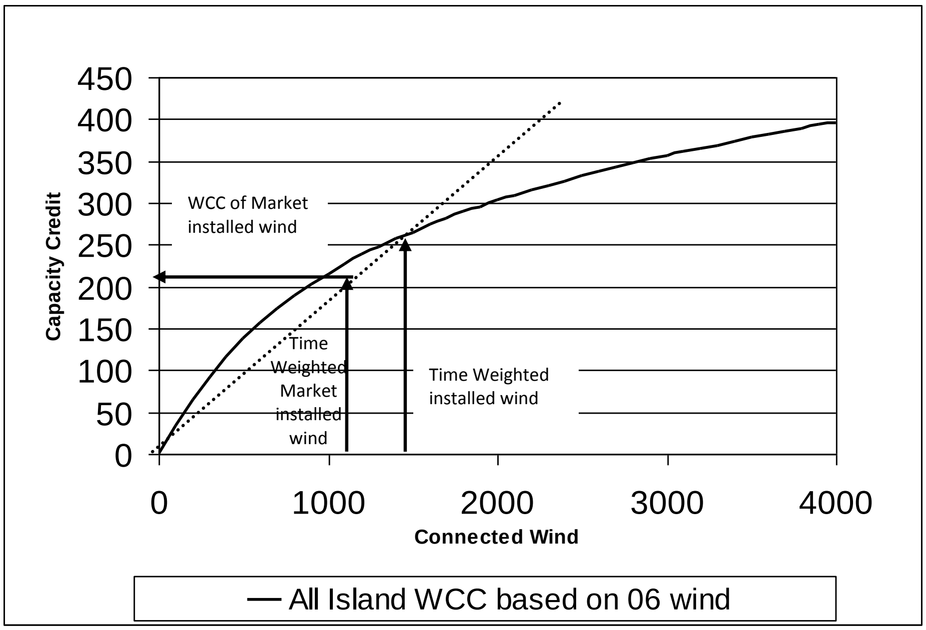



**Figure 3**

## 5 ADEQUACY

The load and generation models are inputted to AdCal and the Loss of Load Expectation (LOLE) is calculated. The extent of surplus or deficit is calculated by adding or subtracting a fixed amount to all half-hours of the demand forecast iteratively (using CLOAD) until the calculated LOLE equals the adequacy standard. Once equality is achieved the total fixed amount added or subtracted to the demand equates to the deficit or surplus respectively and is an amount equal to that deliverable by perfect plant (i.e. plant which has no SOD and a zero FOP).

## 6 SURPLUS / DEFICIT

In order to arrive at a more realistic surplus or deficit it is necessary to convert this perfect plant (PP) amount into a more representative figure by establishing a ratio of perfect plant to imperfect plant (IPQ). The selected approach is to add a reference plant (RP) to establish a scalar to convert the identified surplus or deficit into an imperfect plant equivalent so as to scale the capacity to exactly meet the identified adequacy standard.

## 6.1 REFERENCE PLANT

The RAs have decided that the characteristics of the RP should be as follows:

- BNE Peaking plant in the event of a deficit
- Plant with characteristics determined from the portfolio in the event of a surplus

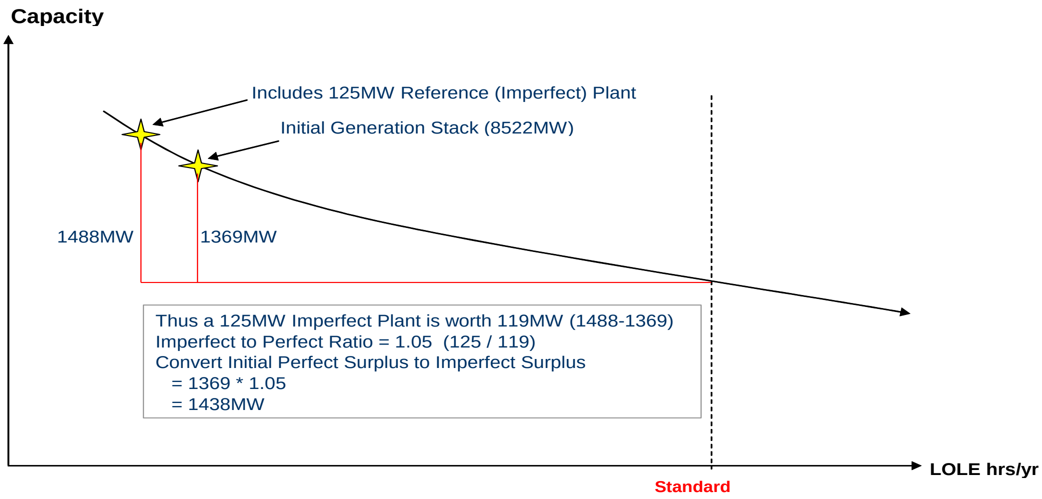
In the latter case when determining the characteristics of the RP the Moyle interconnector is not included in the calculation as it is not a generator unit and its inclusion would distort the data. Likewise, any SSG in the portfolio is excluded as this generation is not representative of the majority of generation in the portfolio. In addition, the capacity of the unit being determined will take the average time weighted capacity into account so as to more correctly account for plant that is being commissioned (or decommissioned) within a year. The FOP will be the target FOP based on NI plant which is applied to all other units. Lastly, the SOD will be the average outage duration over all the installed capacity (excluding Moyle). When this RP is introduced into the portfolio AdCal will automatically determine the timing of the maintenance associated with the unit.

## 6.2 CONVERT SURPLUS / DEFICIT into IMPERFECT PLANT

The method is to introduce the RP into the portfolio of plant and re-determine the amount of perfect plant for the calculated LOLE to equal the adequacy standard. The resulting change in PP will relate to the introduction of the RP. This scalar relationship between RP and PP will be applied to convert all of the surplus / deficit into an IPQ. While generation plant is available in discreet quantities the surplus / deficit will be expressed as a calculated quantity and such 'lumpiness' will not be taken into account.

For an example of the method where the system has a surplus, say the initial portfolio of generation comprises 8522MW of plant and a removal of 1369MW of PP was required to achieve an LOLE of 8hrs/year. Then say a 125MW RP unit is introduced, the surplus increases again and the amount of PP to be removed to get back to the desired LOLE of 8hrs/year increases to 1488MW. Thus 125MW of RP equates to 119MW (1,488-1,369) of PP. Using the ratio 125/119 the initial surplus of 1369MW is converted to 1438MW of IPQ. Note that the diagram below is based on 2008 figures.

Conversion of Surplus from PP to RP terms




## 7 CAPACITY REQUIREMENT TOTAL

The Total Capacity Requirement for Capacity Payment Mechanism consists of the following three components:

**Capacity Requirement = Time Weighted Plant Total + Surplus /Deficit in RP terms + WCC for Wind in Market**

- *Time Weighted Plant Total :*

  The capacities in the plant portfolio are time weighted to reflect their impact of decommissioning / commissioning within a year. Thus a unit that is commissioned half way through the year will contribute only half its total capacity to the Capacity Requirement Total.

- *Surplus / Deficit in Reference Plant terms*

  This has been illustrated above for the situation where a surplus exists. A similar procedure will apply where a deficit exists and the reference plant is a BNE Peaking unit.

- *Capacity Credit of Wind in Market*

  This was described above. As with plant in the generation portfolio the wind capacities should also be time weighted to more accurately reflect their contribution to requirement.

The summation of these three components yields the Total Capacity Requirement in the Market.

# 10 APPENDIX 2 – TABLE 7.4 NI SHARE OF THE CAPACITY POT BY ACER AND BY AN EX-POST MONTHLY DAILY EXCHANGE RATE

| Year | Month | Capacity Pots | % share NI demand € | ACER | £ x ACER | Average of Daily Trading Day Exchange Rate for each Month | £ x A monthly Exchange rate | Variance |
|---|---|---|---|---|---|---|---|---|
| 2008 | Jan | 56,001,701 | 15,170,861 | 0.6851 | 10,393,557 | 0.7471 | 11,333,847 | 940,290 |
| | Feb | 54,685,661 | 14,814,346 | 0.6851 | 10,149,308 | 0.7511 | 11,127,025 | 977,717 |
| | Mar | 52,515,595 | 14,226,475 | 0.6851 | 9,746,558 | 0.7735 | 11,003,933 | 1,257,375 |
| | Apr | 40,755,238 | 11,040,594 | 0.6851 | 7,563,911 | 0.7942 | 8,768,734 | 1,204,823 |
| | May | 38,627,173 | 10,464,101 | 0.6851 | 7,168,956 | 0.7914 | 8,281,394 | 1,112,439 |
| | Jun | 38,683,175 | 10,479,272 | 0.6851 | 7,179,349 | 0.7910 | 8,289,244 | 1,109,895 |
| | Jul | 37,899,151 | 10,266,880 | 0.6851 | 7,033,839 | 0.7934 | 8,145,286 | 1,111,447 |
| | Aug | 39,747,207 | 10,767,518 | 0.6851 | 7,376,827 | 0.7918 | 8,525,793 | 1,148,966 |
| | Sep | 44,017,337 | 11,924,297 | 0.6851 | 8,169,336 | 0.7997 | 9,535,613 | 1,366,278 |
| | Oct | 52,599,597 | 14,249,231 | 0.6851 | 9,762,148 | 0.7880 | 11,228,486 | 1,466,338 |
| | Nov | 58,871,788 | 15,948,367 | 0.6851 | 10,926,226 | 0.8245 | 13,150,112 | 2,223,886 |
| | Dec | 60,817,847 | 16,475,555 | 0.6851 | 11,287,403 | 0.9010 | 14,843,926 | 3,556,523 |
| | **Total** | **575,221,470** | **155,827,496** | **0.6851** | **106,757,418** | **0.7956** | **123,969,451** | **17,212,033** |
| 2009 | Jan | 62,689,306 | 18,054,520 | 0.7944 | 14,342,511 | 0.9236 | 16,674,864 | 2,332,353 |
| | Feb | 61,389,035 | 17,680,042 | 0.7944 | 14,045,025 | 0.8861 | 15,666,096 | 1,621,070 |
| | Mar | 58,967,281 | 16,982,577 | 0.7944 | 13,490,959 | 0.9158 | 15,552,134 | 2,061,175 |
| | Apr | 45,769,532 | 13,181,625 | 0.7944 | 10,471,483 | 0.9011 | 11,877,962 | 1,406,479 |
| | May | 42,502,602 | 12,240,749 | 0.7944 | 9,724,051 | 0.8866 | 10,852,254 | 1,128,202 |
| | Jun | 41,576,159 | 11,973,934 | 0.7944 | 9,512,093 | 0.8587 | 10,282,256 | 770,163 |
| | Jul | 43,006,457 | 12,385,860 | 0.7944 | 9,839,327 | 0.8605 | 10,658,032 | 818,705 |
| | Aug | 43,250,258 | 12,456,074 | 0.7944 | 9,895,105 | 0.8608 | 10,722,620 | 827,515 |
| | Sep | 48,061,260 | 13,841,643 | 0.7944 | 10,995,801 | 0.8893 | 12,309,188 | 1,313,387 |
| | Oct | 59,373,616 | 17,099,601 | 0.7944 | 13,583,923 | 0.9164 | 15,670,020 | 2,086,096 |
| | Nov | 66,378,825 | 19,117,102 | 0.7944 | 15,186,626 | 0.8976 | 17,159,576 | 1,972,951 |
| | Dec | 67,890,389 | 19,552,432 | 0.7944 | 15,532,452 | 0.9006 | 17,609,236 | 2,076,784 |
| | **Total** | **640,854,720** | **173,607,544** | **0.7944** | **137,913,833** | **0.8918** | **154,818,807** | **16,904,974** |
| 2010 | Jan | 55,351,872 | 16,428,436 | 0.8586 | 14,105,455 | 0.8845 | 14,530,792 | 425,337 |
| | Feb | 52,107,209 | 15,465,420 | 0.8586 | 13,278,609 | 0.8749 | 13,530,696 | 252,086 |
| | Mar | 49,381,100 | 14,656,310 | 0.8586 | 12,583,908 | 0.9017 | 13,215,888 | 631,980 |
| | Apr | 38,758,163 | 11,503,423 | 0.8586 | 9,876,839 | 0.8841 | 10,170,061 | 293,222 |
| | May | 38,402,584 | 11,397,887 | 0.8586 | 9,786,226 | 0.8606 | 9,808,452 | 22,226 |