BORD NA MÓNA

BORD NA MÓNA POWERGEN

Submission by Bord na Móna PowerGen

on

CPM Medium Term Review

Work Packages 1 to 5

Historical Analysis of CPM
And Proposed Decisions

SEM-10-046

CPM Medium Term Review
Work Packages 1 to 5
Historical Analysis of CPM and Proposed Decisions
Response to Consultation

Introduction

Bord na Mona welcomes this Medium Term Review of the Capacity Payments Mechanism (CPM). The CPM is a fundamental structure of the Single Electricity Market, which is designed to play a critical role in giving the correct investment signals to the market to deliver the appropriate mix of generation required to ensure an efficient and secure electricity supply.

Bord na Mona agrees with the Regulatory Authorities that the rationale for the CPM in the SEM remains valid, and believes this will only strengthen as the average load factor for generators drops in the future with increasing penetration of variable renewable generation. This review aims to ensure the correct signals are in place as intended in the SEM design objectives, with a particular focus on long term signal for new entry and investment. It is critically important in this regard that the RAs address the issues raised in previous consultations on the CPM and annual BNE consultations on the stability of the mechanism used to set the Annual Capacity Payment Sum, (ACPS).

The SEM is in operations for almost three years, and during that period the SEMC has set an ACPS for 5 full calendar years, (this was completed in four separate processes, as the process for the calendar years 2007 and 2008 were effectively completed as a single process). Bord na Mona has acknowledged in its responses to the consultations on these processes a significant improvement in the methodology used by the RAs, especially over the last two years where specialist consultants have been commissioned to assist in the process, and a more rigorous and consistent framework has been developed. Whilst this has improved the predictability to some extent, there remain a couple of significant sources of volatility in the process, which we believe need to be addressed in this review process. These are,

- The reduction of the BNE costs for deemed Infra Marginal Rent in the Energy Market
- The process by which the WACC is determined

The first of these points is covered in Work Package 3 and our response is discussed in more detail below. The second point should be addressed in a different work package which should be the subject of a future consultation.

Whilst acknowledging the efforts of the RAs to consult on the BNE peaker cost factor of the ACPS, Bord na Mona has consistently called for more consultation on the determination of the deemed capacity requirement. We believe that this factor of the CPM is equally important to the longer term stability of the investment signal in the market, and should be treated in an equivalent manner in the consultation process. It is recognised that the RAs have improved the transparency of the data used in the calculation in recent years, and have strived to give more clarity to the calculation process. Nonetheless, Bord na Mona believe it is equally appropriate to consult on the key input assumptions, such as the Forced Outage Probability as it is for other input parameters used in the assessment of the BNE peaker cost. The deemed capacity requirement is discussed further under WP2 below.

In terms of the process itself, it would be useful to get some clarity from the RAs as to what the medium term actually represents – i.e. will the CPM be reviewed on a regular basis, and what is the expected interval between review processes.

Work Package 1 – Historical Analysis of the SEM

The analysis of the historical data with respect to the long term ex-ante, short term ex-ante and short term ex-post disbursement of the Capacity Sum shows that these factors are working as designed, by weighting payments to the periods of lowest margin within each capacity period. It is noted that the period over which the analysis was conducted, (Jan 09 – Jun 09), showed relatively high levels of margin, (between 2,000 MW and 4,500 MW for the daily average profile). Looking at the profile of payments versus margin within each individual month, (capacity period), it is clear that payments are weighted to reward capacity for those periods where the relative margin was at its lowest point during the month, regardless of the absolute level of the margin for the month in question. It should be safe to assume therefore that the mechanism will work appropriately, where the absolute level of the margin is at much lower levels. This gives confidence that the disbursement of capacity payments is giving the appropriate signals to generators to provide the capacity when it is most needed.

In relation to the time of day profile of payments, there was some discussion in the paper on the level of fixed payments paid out during the hours from midnight to 6:00 am. The level of the fixed element in Figs 3.12 and 3.14 reflect the typical load shape that would be expected for the respective quarters. These load profiles would have been used to set the fixed weighting factors before the start of the year.

There is, by design, a trade off between the level of certainty given to generators with the fixed element of the capacity pot, and the short term signal given by this element of the payment. This issue was extensively debated during the development of the CPM payment weighting factors. Bord na Mona believes that the 70%/30% ratio for the short term factors relative to the fixed weighting factor gives an appropriate balance between the short term signals to provide the required capacity during periods of tight capacity margin, and the longer term certainty over capacity revenues for generators.

Work Package 2 – Review of Capacity Requirement

As discussed in the introduction, the determination of the deemed capacity requirement is as important to the long term market signal from the CPM as the determination of the BNE peaker costs. It is therefore appropriate that the SEMC should consult on the main input assumptions used to derive this estimate, especially the assumptions used in the estimation of demand growth, any changes to the demand profile, the forecast wind series and generator unit forced outage probabilities.

The issue of forced outage probability, (FOP), has been raised in responses to the BNE consultation paper every year by various participants. The RAs have repeatedly indicated that the FOP estimate for all generators, regardless of age or technology should be fixed based on an historical performance of NI plant over a 5 year period from 2002 to 2006. Whilst it is recognised that the mechanism should incentivise good performance, there is a concern that the reference level used may not reflect a realistically achievable standard for the all-island portfolio on a sustainable basis. The impact of increased plant wear and tear with plant life, and the effect of increased cycling of plant will impact negatively on the ability of the plant to maintain the levels of availability that may have been achieved previously. It is therefore appropriate that the FOPs be subject to some sort of regular review, as part of the process, to ensure that the deemed capacity requirement can actually delivery the minimum security standard required for the market. In addition, it would be useful as part of this review, to determine the sensitivity of the deemed capacity requirement to FOP, which was done on a very limited basis a number of years ago. We believe it is appropriate to carry out such a sensitivity as part of the annual assessment process, as it would provide an indication of the amount of additional capacity that may be needed if the target FOP is not achieved.

Section 4.3 discusses the reserve margin of the deemed capacity requirement over peak demand which has been raised by Bord na Mona in a number of our responses to consultations on the BNE peaker costs. The methodology used only considers the units committed to meet demand, without considering the requirements for units to provide reserve or manage transmission constraints in the unit commitment schedule. The resultant deemed capacity requirement over the past number years has indicated that a reserve margin of only 3% - 4% over peak demand is sufficient to adequately serve demand in the market, while relying on a level of capacity credit from wind. It is likely that if the market were in equilibrium with just the amount of capacity incentivised by the deemed capacity requirement, there would be periods where demand would have to be curtailed, (especially at low wind output) because there is not enough dispatchable capacity to provide reserves. Bord na Mona believes that to give the appropriate long term signal for the correct level of capacity not just to meet a reasonable level of demand, but to ensure the secure and efficient operation of the transmission system, the calculation of the capacity requirement should be adjusted to factor in the provision of reserves, and the management of transmission constraints.

Section 4.4 discusses the impact of wind on the capacity requirement calculation. The analysis of high wind indicates that an increase of threefold increase in wind output reduces the capacity requirement by ~240 MW, which represents a marginal capacity credit for the additional 4,000 MW of wind of approx 6%. Even at high wind output on the 200 peak demand periods, the marginal capacity credit only increases to 8%. This highlights the low contribution of wind to generation adequacy, especially at high penetration levels, and the fact that the contribution towards the capacity pot in terms of capacity requirement is much lower than the capacity eligible for payment, which is based on actual output, (estimated to be approx 30% average load factor for 6000 MW of wind). Given the fixed revenue basis of the CPM, this means that other plant that offer more reliability to the market are under rewarded for the deemed value of their capacity, which diminishes the economic signals to develop such plant. The RAs may discuss this area further under the Treatment of wind in the CPM work package; the analysis will be relevant to that discussion.

Work Package 3 – Infra Marginal Rent and Ancillary Services deductions

The issue of Infra-Marginal Rent deduction for the peaking plant is probably the largest potential source of uncertainty and risk in the CPM, in terms of the long term investment signal given by the mechanism. This arises primarily, as acknowledged in the paper, due to the perverse signal given by CPM in years where the capacity margin is tight and new capacity is needed. In these years, the principle of deducting IMR acts to significantly lower the level of the ACPS contrary to the signal that the mechanism should give, to incentivise new investment in the market when it is needed.

The consultation paper discusses the potential infra-marginal rent which could be earned by a gas fired peaker plant operating in the market. It is estimated that such a plant would have earned an inframarginal rent of approx €8.8m on the basis of 2010 fuel price assumptions. It is not clear from the results as presented what the market load factor for the gas fired plant was, but it is clearly significantly higher than the 5% upper range suggested for the BNE peaker plant (as a 5% load factor would represent an average margin of > €100/MWh). It is also inconsistent with the assumptions for the booking of peak day gas transmission capacity, which is limited to 4 hours on the basis that Plexos modelling indicates very infrequent running of the peaker in 2010 and 2011[1]. It would be useful to inform the process of IMR assessment, if additional data could be given in relation to market schedule quantities, bid prices and revenues from the Plexos modelling runs.

The RAs acknowledge in the paper that the IMR deduction represents significant and genuine volatility in the CPM, and express the wish to remove this volatility if possible. However, the option of eliminating the IMR deduction is immediately discounted because the RAs feel that in equilibrium, (i.e, where the market has insufficient generation) the BNE peaker will earn IMR which should be deducted from the CPM.

A couple of options are presented to remove the volatility associated with the IMR deduction. Option 1 proposes that the IMR deducted be set to a value, equivalent to the IMR which would be earned if there were no price cap in the market with 8 hours of un-served demand per year. This would effectively completely eliminate the capacity payment pot, and would place the equivalent risks on generators as if the SEM were an energy only market, without the associated ability to bid a scarcity premium at times of insufficient generation. In addition, without concurrently adjusting the SEM price cap up to VOLL, the BNE peaker would have to be dispatched at full output for approx 80 hours per year with the SMP set to the current level of the price cap, to enable it to recover its fixed costs.

The second option is a variation on the first, where the IMR deduction is based on an assumed dispatch of 8 hours per year at the where SMP reaches the price cap. Again, this option is based on as assumption that can only happen if the market is consistently not meeting demand for a significant number of periods per year, which can only occur if the market is not functioning correctly. By definition, if the market

[1] From 2011 BNE decision paper, ref SEM-10-053

is adequately meeting demand, the BNE could not cover a significant portion, (of the order of 10% of its fixed costs) if this option were adopted. Furthermore, a rational investor would not develop such a plant without believing that this under-provision of service would be maintained over the period required to recover their investment. There have only been a couple of periods since the market has been in operation, where the SMP has reached the price cap. Therefore, this option would act to provide a significant impediment to investing in new capacity in the market.

Bord na Mona believe that the RAs should re-consider their view on abandoning the principle of deducting the IMR altogether, as we agree that the status quo arrangement adds significant volatility to the CPM, and therefore acts as a significant impediment to investor confidence in the market. As mentioned above, the current arrangement also gives a perverse market signal, reducing capacity revenues as the times when they are most needed. By contrast, if the IMR deduction was removed, the typical status quo would be zero IMR for the BNE peaker, (as has been the case for the last number of years) with an additional incentive to invest in new capacity as reserve margins tighten, due to the opportunity to earn some short term infra-marginal rent.

The issue of deduction of Ancillary Services revenues are also discussed in this context. Bord na Mona acknowledge that the BNE peaker will probably be awarded an AS contract. However, the TSO has acknowledged to Bord na Mona previously, that there is no guarantee they will contract for any level of service above the grid code minimum, and that the actual contract levels will depend on requirements and transmission system constraints. We therefore suggest it is more appropriate that the assessment of BNE AS revenues be based on a median view of the AS contract levels available from the plant, as a more conservative estimate of the potential revenues available to such a generic plant.

Work Package 4 – BNE Peaker Plant Options

The level of analysis that has been undertaken over the last number of years to evaluate the technology choices for the BNE plant has been quite exhaustive. It is also unlikely that significant changes in the technology options will arise on a year to year basis, but will evolve over the medium term as technology is developed, and has demonstrated significant operational hours to prove its reliability. Bord na Mona therefore suggest that the selection of technology choice by reviewed on a less frequent basis, of the order of every three to five years. This would reduce the workload of the RAs, and remove another potential source of variation in the process from year to year.

Bord na Mona agree with the view of the RAs that the market for secondary trading of gas transmission capacity is insufficiently developed, and that an operator of a gas fired peaking plant would therefore have to buy annual capacity.

We also agree with the analysis that the other technology options considered, i.e. demand side response, aggregated generator units, pumped storage and interconnectors are unsuitable for selection as the BNE peaker plant.

Work Package 5 – Exchange Rate Risks

The issue of exchange rate risk represents a potential gain or loss due to currency fluctuations from suppliers to generators, (or vice versa). This currency risk would be thrown onto the market if the ACPS was split into two separate sterling and euro jurisdictional pots, as there would be impossible to match the payments in each currency with the respective charges in the same currency. We therefore agree that the CPM should remain as a single market pool of money, and not be separated into two jurisdictional pots.

In principle, Bord na Mona do not have think that a monthly exchange rate should present a significant challenge to the market operations, as the capacity payments and charges are paid and collected on the basis of stand-alone monthly pots. It would remain to affected participants to determine what the most appropriate mechanism would be to set a monthly exchange rate, and to how to manage any additional currency exchange risks that might arise.

Summary

In summary, the key points Bord na Mona would like to emphasise in relation to our response to this consultation paper are

- The rationale for the CPM remains valid, though it is appropriate and timely to review it, to determine if its design objectives are being optimally met.
- The RAs should consult on an annual basis on the key drivers of the deemed capacity requirement, as well as the BNE peaker costs.
- The deemed capacity requirement should consider the amount of capacity required to provide reserves and relieve transmission constraints, as well as serving demand.
- The most appropriate solution to the volatility introduced to the CPM investment signal by the deduction of infra-marginal rent, is to simply eliminate the principle that IMR is deducted from the BNE peaker price.

For and on behalf of
Bord na Mona PowerGen,

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