Power NI Energy Limited
Power Procurement Business (PPB)

Fixed Cost of a Best New Entrant Peaking Plant
&
Capacity Requirement
for the Calendar Year 2013

Consultation Paper

SEM-12-029

Response by Power NI Energy (PPB)

19 June 2012.

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Power Procurement Business

Introduction

Power NI Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper on the Fixed Cost of a Best New Entrant Peaking Plant and the Capacity Requirement for the Calendar Year 2013.

General Comments

PPB is concerned that the consultation paper fails to make any comment on a "SEM" WACC that better reflects the all-island nature of the market and we are disappointed that the proposals in the consultation paper continue to apply the relevant jurisdictional WACC. This is surprising as the CPM Medium Term Review Final Decision Paper noted in section 3.3 that the SEM Committee would be reviewing additional information on the WACC (that was to be procured by the RAs from the BNE consultants) and would then determine the methodology to be used for the 2013 consultation. While Annex 3 of the CEPA/PB paper includes some consideration of a "SEM" WACC, it appears that the SEMC has decided to ignore it and the consultation paper fails to make any comment on it in its proposals for 2013.

This omission is also concerning given that this is the first time where it is proposed to "fix" the BNE for 3 years, spanning a period to 2016 when some older capacity will be closing down and the installed capacity of intermittent renewable generation is expected to increase significantly. It is therefore crucially important that the BNE price, which sets the investment signal for new capacity, is correctly determined to ensure an appropriate and sustainable investment signal exists.

The rest of this section addresses PPB's strategic comments on the proposals and PPB's more specific comments follow in the next section.

The unit will operate in a single market and hence the market risk is common, regardless of physical location

As we have expressed in our responses to previous consultations, the SEM is an all-Ireland market and any rational investor seeking to invest in the market will view the risk of operating in the SEM as a single risk, regardless of the potential location of their generating unit. Therefore while there would be a small variation in the pre-tax WACC as a consequence of different taxation rates, the fundamental components that make up the return required by an investor in the SEM should be common. Electricity demand in RoI is roughly three times the demand in N. Ireland (NI) and hence the perception of risk by investors considering an investment in the SEM would naturally be more heavily influenced by the economic climate in RoI.

This view is confirmed in Annex 3 of the CEPA/PB paper which states that "*the SEM is an all-island market and therefore the risk of payment default by a market participant on their financial obligtions in the SEM covers both NI and the Ro*I", and that "*this implies that investment risk – driven by payment default in the SEM – of the BNE located in NI (RoI) is as much dependent on payment and credit risk of market participants domiciled in the RoI (NI) as NI (RoI)*".

The BNE will remain constant for three years

One of the SEMC decisions from the Medium Term Review was for the BNE to be fixed for three years, inflated on the basis of inflation in the region within which the BNE is situated. Our response to the draft decision highlighted that it was impossible to provide meaningful comment on the proposals as no analysis had been completed to demonstrate the impact of any of the options.

Further, the SEMC decided to "fix" the overall BNE price rather than individual elements of it. We understand that this "fixing" includes the exchange rate used to derive the BNE. The consequence of this approach is that the BNE price is unresponsive to changes in actual foreign exchange rate movements which has the potential for greatly increasing the volatility of the CPM revenues for generators based in Northern Ireland since CPM payments are paid and converted to Sterling using the Annual Capacity Exchange Rate which is set each December for the following calendar year. Such an outcome is completely at odds with the objective of the Medium Term Review and reflects the concerns we have previously raised that no analysis of the consequences of the "fixing" had been completed or consulted upon.

While it would be possible to also fix the Annual Capacity Exchange Rate for three years (which the RAs proposed in its note following the CPM workshop on 6 June), this starts to divorce the BNE totally from reality and, conceptually, we consider it would be better to fix component elements within the BNE calculation which could be adjusted to reflect the current foreign exchange rates, thereby ensuring there is greater linkage to reality. This may also avoid a step change at the end of the fixed period. However, this would require analysis to be undertaken to evaluate and verify the potential effects.

Other Medium Term Review outcomes

In addition to our concerns in relation to the WACC and the "fixing", we would also like to emphasise that PPB continues to have the same opinions and objections, as set out in our 13 January 2012 response to the CPM Medium Term Review draft Decision Paper, particularly in relation to (i) the deduction of conceptual IMR that generators are very unlikely to earn in reality, (ii) the use of an artificial "target" FOP of 5.91% which understates the capacity requirement, and (iii) the proposals in relation to increasing the Flattening Power Factor which would increase CPM volatility and conflicts with the need to facilitate market coupling.

It should also be recognised that capacity payments to generators are continuing to be diluted as additional renewable capacity commissions and as plant returns from long term outages (e.g. Moyle for part of 2011/12 and Turlough Hill) and with the commissioning of the East-West Interconnector expected later this year.

While it is difficult for us to challenge many of the individual elements of the determination of the BNE price without procuring a report to challenge the CEPA /PB paper, there are a number of elements that we believe serve to understate the BNE price that we comment on in the Specific Comments section below.

Specific Comments

Electrical connection costs

The CEPA/PB paper notes that the electrical connection costs have been updated to 2012 costs by assuming a 2% increase in metal costs. However, no change has been included to reflect the change in exchange rates when converting the cost from £ to € .

Gas connection costs

The paper assumes the cost of gas connection has not increased in the last year notwithstanding that there has been a general increase in fuel, labour and material costs over the period. We would have expected some cost increase.

Similar to our earlier comment on the electrical connection costs, the exchange rate has changed and hence the cost of the gas connection for the NI unit should reflect the change in the €/£ rate between 2011 and 2012.

Gas transportation costs

The consultation paper states that in relation to Northern Ireland, the analysis has used the indicative postalised tariff for 2012/13 that was published as a forecast alongside the 2010/11 tariffs. This is an old forecast and the estimate for 2012/13 was updated when the 2011/12 tariff was published in August 2011. This estimate of £0.36782/kWh/d is c4.6% higher than that used by CEPA/PB and at the very least, this latest figure should be used. In addition, actual gas consumption in 2011/12 has been lower than previously forecast and therefore the estimated gas transportation charges for 2012/13 may be understated. The actual tariff for 2012/13 is scheduled to be published in August 2012.

Initial Fuel Working Capital costs

As we have stated in response to the consultations in previous years and as we highlighted at the workshop on 6 June 2012, it is not correct for the cost of the initial working capital requirements to fund the purchase of fuel stocks to be the same in Northern Ireland as it is in RoI. Distillate in Northern Ireland attracts Excise Duty that is payable when purchased although it can be reclaimed when consumed to generate electricity. Hence the Duty is a cost that initially must be funded. The current rate of 11.14pence/litre is scheduled to increase to 11.72pence/litre (which equates to over £140/tonne) from August 2012[1].

The Carbon Price Floor is also to be implemented for liquid fuels by means of Hydrocabon Oil Duties and hence the costs arising from the arrangements must be reflected in the BNE working capital costs.

[1] http://www.hmrc.gov.uk/tiin/tiin866.pdf

Residual Value of Land & Fuel

As we also highlighted last year, it is not clear why the residual value of Land and Fuel is significantly higher for an NI based peaker compared to one based in RoI. The initial fuel costs are similar and hence the variance must be due to the residual land value. However, the Belfast West site is subject to a Fee Farm Grant from the Belfast Harbour Commissioners that restricts the use of the site to electricity generation. Any lease of the site from the NIE Landbank must reflect this restriction and we would expect that, as in the past, the lease would be structured to terminate once generation ceases on the site such that the site reverts back into the Landbank. Hence we would expect the residual value of the site to be negligible.

WACC proposals

Our understanding is that the market data presented by CEPA broadly reflects the ranges witnessed in the market. Our concern is therefore not with the fundamentals but with the interpretation and use of the information garnered which we consider results in the individual WACCs determined for NI and RoI being understated.

In relation to the proposed UK WACC, the cost of debt proposed is low and the debt premium (1.75%) used is the lowest figure from the CEPA range. It is also unclear why the 50bp uplift has only been added to the top end of the debt range premium to account for a premium on UK utility debt and surely this premium should apply across the range. The rates proposed is also strongly linked to proposals for the NIE T&D price control proposals for 2012-2017. However these are merely proposals and in any event reflect a very different business to that of a peaking generator with very different risks.

In relation to the proposed RoI WACC, it is very difficult to fathom why the cost of debt proposed is lower than that used for the 2012 BNE calculation and the figure of 3.5% used as the low cost seems to be under-stated and to be out of line even with the current cost of RoI gilts.

We note the exchange at the 6 June workshop which confirmed that unlike in 2009, CEPA has not held direct discussions with the banking community to assess the current costs experienced by projects investing in the UK and Ireland. As it is proposed to fix the BNE for three years, it is even more critical for the correct WACC figures to be utilised and we believe that such discussions should be conducted with the banking community to obtain the evidence of actual investment experience before making any final decision on the WACC parameters and the WACC to be adopted in the final BNE decision.

These discussions should also seek to obtain views on the sustainability of separate UK and RoI WACCs in the SEM and these discussions may also help to identify or confirm how such a SEM WACC should be determined.

As we have previously noted, our view is that it is not plausible to determine widely different WACCs for generators locating in Northern Ireland and RoI but who are operating in a common single electricity market. We welcome the CEPA analysis of the blended WACC although we do not understand why the blending is based on a 70:30 weighting and consider that a 75:25 weighting would be more appropriate based on the relative jurisdictional demands as shown in Table 14.1 of the consultation paper.

We do not agree with the CEPA suggestion that a point estimate, rather than continuing with the existing practice of adopting the mid-point within ranges, could be adopted to determine a SEM WACC. This opens up concerns over selective regulatory risk and we believe that it is more appropriate to continue to adopt mid-points within the coherent ranges.

IMR deduction

Notwithstanding our general objection to the deduction of IMR from the BNE price, there are a number of significant flaws in the calculation proposed.

The calculation of the IMR is overstated as it ignores the Startup cost of a peaking units which should be included in the formula (copy provided following the 6 June workshop) to determine the weighted average bid price. It is likely that the peaking unit will only be required for one settlement period and hence the full startup cost should be included.

TLAFs are not included in the formula yet any energy revenue received by a generator in the SEM is determined from MSQ * TLAF * SMP and hence the relevant TLAF should be applied to the result. i.e.

IMR Deduction = [(PCAP - BID) / 1000] * Outage Time * (1 - FOP) * TLAF

It is not apparent why the average bid is based on all the peakers in the SEM. As the BNE peaking unit is located in Northern Ireland then it would be logical to use the average bid price of the Northern Ireland distillate fired peaking units.

The proposal is for the IMR to also be effectively fixed for three years as part of the BNE "fixing". However, this is likely to result in a distortion between the actual bid cost of the unit and the "fixed" bid used to determine the IMR deduction. Distillate prices have risen historically and any review of prices shows that the price has trebled over the last ten years. Hence oil price inflation has greatly exceeded general inflation and hence it would be wrong to merely "fix" the bid price at a point in time. Similarly, the bid price also includes the cost of CO_2 permits and while these are currently at a low price, the expectation is that the EU must address the carbon market, e.g. by withholding permits. Locking in the current CO_2 price is likely to overstate the IMR if it is fixed for three years.

Similarly, the UK is introducing a Carbon Price Floor from April 2013 and rates have been published for 2013/14 and 2014/15. The bid price would need to be adjusted to reflect this cost that is to be imposed from April 2013. As the rate varies through the period, an average (or perhaps the mid year 2014/15) rate should be used to adjust the bid price.

Ancillary Service revenues

It appears as though the deduction of AS revenues is also fixed for the three year period. If this is correct then this also creates an artificial exposure and volatility risk for Northern Ireland generators whose actual AS revenues will be exposed to the actual Euro/Sterling exchange rate.

Capacity Requirement for 2013

We note the caveats in relation to the demand forecasts and agree that they should be re-assessed closer to the date of the final decision.

As we have noted in our previous responses, we continue to disagree with the use of “target” forced outage rates and believe that actual rates (averaged over a number of years) should be used which more accurately reflects the risk to security of supply.

PPB has consistently raised concerns about the treatment of wind and we consider that the methodology adopted whereby the wind trace is deducted from demand before determining the conventional capacity requirement to meet that residual non-wind demand curve, and then adding back the Wind Capacity Credit, under-estimates the true plant margin required and hence results in an under-stated Capacity Requirement. This problem is likely to increase as the wind capacity increases and it was clear from Eirgrid’s response at the 6 June workshop that they have not considered the implication of removing such a large and increasing wind trace from the demand curve and excluding that from the probabilistic analysis.

As we also expressed last year, our concerns are further highlighted by the experiences over the last few winters when during the cold spells, high pressure resulted in minimal generation by all the wind generators. With conventional plant, FOPs are normally independent, although, in the All-Island Generation Capacity Statement for 2011-2020, the TSOs state that recent cold spells demonstrated that simultaneous failure of generators does happen and failure is not entirely independent, and is likely to coincide with period of high demand. This is even more evident with wind output during such periods and we agree with the TSOs assertion that treating outages independently will over-estimate system adequacy. This methodology is also used in the determination of the Capacity Requirement and therefore it fails to properly take account of the risk, with the result that the Capacity Requirement is under-stated.

Other comments

We assume that all the cost elements that are associated with the WACC or the underlying cost of debt (e.g. Interest during construction costs) will be modified to reflect the final WACC that is adopted.