NIE Energy Limited
Power Procurement Business (PPB)

Fixed Cost of a Best New Entrant Peaking Plant
&
Capacity Requirement for the Calendar Year 2012

Consultation Paper

SEM-11-025

Response by NIE Energy (PPB)

10 June 2011.

NIE energy
Power Procurement Business

Introduction

NIE 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 2012.

General Comments

PPB is concerned at the change in the proposed Annual Capacity Payments Sum (ACPS) for 2012 which is approximately 4.6% lower than the amount for 2011 (which was also lower than the 2010 ACPS). The reduction arises from a reduction in the proposed BNE Peaker Cost and again highlights the volatility of the CPM which was to be a more stable element of the market pricing.

It should also be recognised that capacity payments to generators have been greatly diluted in 2011 with the full year operation of the CCGTs at Aghada and Whitegate, and will continue to dilute as additional renewable capacity commissions through the course of 2011 and 2012.

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.

In addition there are three key strategic matters that would indicate the selection and pricing of the BNE plant is flawed and incorrect.

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

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.

We also note the recent comment of Peter Dooley, the Managing Director Debt Capital Markets at RBS Global Banking and Markets, who comments

"UK regulated distribution networks, widely recognised as the most stable across the energy value chain, are currently trading in the region of 140bps - 160bps over the UK Gilt yield.

NIE's unrated 2018 bond is currently bid at Gilts plus 275 bps points, and its recently issued bond (rated BBB+) priced at Gilts plus 250bps. ESB's BBB+ rated sterling bonds are quoted at Gilts plus 420 bps points and it is apparent that bond investors require a substantial premium for regulated distribution credits with an Irish connection.

Given that regulated distribution is viewed as the least risky end of the spectrum, it would be expected that financing of a generation facility would attract a debt premium, potentially significantly, greater than that attracted by regulated utilities."

It is evident from the recent bond issues by NIE that the cost of debt for a "wires" business operating solely in Northern Ireland has been at a premium compared to similar debt raised by regulated distribution networks in GB. This implies the market attaches additional risk to Northern Ireland, even where the organisation is not relying on RoI revenues and the ESB debt attracted an even higher premium. Investment in a Peaking Plant to operate in the SEM clearly carries much more risk than a regulated T&D business such as NIE and therefore the cost of debt and equity for a BNE investor will be higher again, reflecting the additional market risk.

The WACC proposed for a BNE based in Northern Ireland is clearly too low and we believe that the return required by investors to invest in the SEM would be substantially the same regardless of the physical location of their investment (with any difference largely reflecting the different taxation rates).

The evidence from actual investment decisions

For the last few years the BNE plant has been located in Northern Ireland and has been the Alstom GT13E2. However, it is evident that no actual investors have chosen this technology and all the new OCGT plants are locating in RoI (as noted in section 4.2 of the CEPA/PB paper, two new units OCGT units recently commissioned at Edenderry with Cuilleen, Suir and Caulstown scheduled to commission in 2013 and 2014). The profile of actual investment clearly raises concerns about the veracity and integrity of the BNE plant determination and the inconsistency with actual investment decisions in relation to peaking plant.

Location is at odds with the locational signals provided by the indicative Generator TUoS tariffs for 2011/12

The indicative Generator TUoS charges for 2011/12 that were recently published show a large increase in Generator TUoS charges for generators located in Northern Ireland and the average charge for generators in Northern Ireland is higher than for generators located in RoI. The GTUoS signal therefore points new generation towards location in RoI which is at odds with the recommendation for the BNE plant.

Specific Comments

Gas transportation costs

The paper states that in relation to Northern Ireland, the analysis has used the indicative postalised tariff for 2011/12 that was published in August 2010. We understand actual gas consumption has been lower than previously forecast and therefore the estimated gas transportation charges for 2011/12 may be understated. The actual tariff for 2011/12 is scheduled to be published in August 2011.

As we have commented in previous years, it is not clear that basing the gas capacity requirement on 4 hours operation is prudent. This is particularly relevant as gas nominations cannot be profiled and must be provided in a flat 1/24$^{\text{ths}}$ profile. Hence it would be impossible to deliver the gas to operate the plant at short notice without either incurring gas balancing penalty charges or being restricted. There have also been occasions where peaking plant have operated for longer than 4 hours and we would suggest the gas capacity requirement should be based on a 12 hour operational requirement, or where 4 hours are retained, a cost should be included for imbalance charges.

Initial Fuel Working Capital costs

The paper determines the initial working capital requirements to fund the purchase of fuel stocks. However, it is not clear why the cost is the same in Northern Ireland as 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 is 11.14pence/litre which equates to over £133/tonne.

Residual Value of Land & Fuel

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 were 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.

Transmission Use of System Charges

The estimates of Generator TUoS charges are based on the rates that applied in 2010/11. The TSOs recently published indicates rates for 2011/12 which are a significant increase for Northern Ireland based generators. Using the indicative rate quoted for Kilroot as a proxy for a generator connected at the Belfast West site, the annual GTUoS cost would increase to c€1.07m. This change must be reflected in the final determination. The change also highlights the risks of operating in the SEM and should be reflected in the WACC.

WACC proposals

As we noted in our strategic concerns above, 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 market. The overall cost of debt, regardless of location, must reflect the general market conditions. There is also evidence of the market cost of debt following, for example, the recent bond issues by NIE which provides an indicator for the cost to a network business. The rate for an investment in generation would attract a further debt premium. It is therefore clear that the current WACC proposals for an NI based plant are incorrect and should be significantly higher, reflecting the actual market view of investment in Ireland.

Ancillary Service revenues

While the calculation of Replacement reserve (de-synchronised) is easily verifiable, the derivation of the remaining revenues is not set out in either the RAs consultation paper or the CEPA/PB paper and hence it is not possible to comment on the figures. In any event, there is no certainty of being scheduled and hence no revenues for POR, SOR, etc should be included.

Capacity Requirement for 2011

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.

This anomaly is further highlighted by the reference in section 13.3.2 which states that "*the growth in demand is partly offset by the introduction of the new interconnector which has a higher availability than a traditional conventional plant*".

This interconnector is "scheduled" to commission in Autumn 2012 and therefore in the first instance, the risk of delay should mean there should be a much higher risk applied to its potential availability in Quarter 4 2012. It also further highlights the inconsistency of using the physical plant and interconnectors available in the market to determine the capacity requirement but then using aspirational FOPs. If the actual generating units are to be used, then their historic FOP performance should also be used. The hoped for improvements in line with observed improvements following privatisation in Northern Ireland has not materialised in the 4 years since the commencement of the SEM (and the basis of a small improvement in the past year is unproven and may merely be due to lower utilisation of some units, resulting in higher availability because they were not called to operate).

The treatment of wind remains unclear but from our understanding we consider that the determination of the required margin, when wind trace is deducted from demand and then adding back the Wind Capacity Credit, under-estimates the true plant margin required and hence results in an under-stated Capacity Requirement.

Our concerns are further highlighted by the experiences over the last two 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, as noted in the TSOs recent All-Island Generation Capacity Statement 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

There is an inconsistency in the exchange rate used. The RAs consultation paper quotes the exchange rate used in the assessment as £1=€1.1351 (on Page 15) but this is slightly different to the exchange rate used by CEPA/PB which is quoted to be £1=€1.1317 (page 36 of the CEPA/PB paper). The final figure used should be applied consistently.