SEM-11-025: Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2012

Endesa Ireland welcomes the opportunity to respond to the consultation paper on the Fixed Cost of a Best New Entrant Peaking Plant and Capacity Requirement for the Calendar Year 2012. The revenue certainty provided by the capacity payment is a pillar of the SEM. As generators are required to offer in to the market at their SRMC, we are dependent on the capacity payment for recovery of fixed costs. Greater transparency is needed in the inputs to the BNE calculation to provide greater certainty and to allow market participants to predict changes to the capacity pot. We appreciate that the SEMC has initiated a consultation process in relation to this, however, we would have hoped for this transparency to have been in place for the 2012 Capacity Requirement consultation paper.

In particular, Endesa Ireland questions the proposed WACC used in the calculation of the BNE FC for 2012. Given the current economic climate and our experience with the markets, we consider that the proposed WACC is significantly lower that the WACC a rational investor would need to take into account. Endesa Ireland requests that the RAs identify a source for the inputs to the WACC calculation that will be utilised in future BNE calculations. In addition, we consider that an investor in the all-island market would take into account the all-island economic situation when calculating a WACC and a blended WACC would be more appropriate for the BNE.

Endesa Ireland also considers that greater clarity is needed in the calculation of Ancillary Service Revenues and the GPIs that will be attributable to the BNE. The lack of detail surrounding these calculations makes it difficult to properly assess the proposals set out in the consultation paper. While we appreciate the response to queries relating to this that we submitted to the RAs, we consider that this detail should be included in the consultation paper so that all market participants would have the opportunity to analyse the proposals.

Technology Options

Endesa Ireland recognises that the RAs select the least-cost generator for the BNE plant, as the intention is to mimic the selection of a rational investor. A rational investor must take into account the additional environmental costs of any generation unit. There will be additional fixed costs for less environmentally-friendly plant, including the carbon levy (in Ireland) additional costs for obtaining an IPC licence and planning permission (in both jurisdictions) and an additional contribution to "community gain" funds as the investment will have a more significant impact on the community living in the area of the new unit.

Any new generation to be commissioned in the SEM must be Grid Code compliant or significant penalties will be imposed upon the generator. The proposed BNE is not Grid Code compliant in respect of Reactive Power, as discussed below in more detail. Given the current focus of the TSOs on generator Grid Code compliance, Endesa Ireland would expect that the RAs would select a BNE that is able to meet all Grid Code requirements. If a non-compliant technology is chosen, GPI provisions for non-compliance must be included in the BNE calculation.

It is also submitted that the installed capacity of the proposed BNE is too large. Given the expected increase in the penetration of renewables needed to meet the 2020 targets, it would be more advantageous from a system point of view for smaller units be constructed in areas near windfarms. This would help to ensure voltage stability, a local problem with potentially wide-spread impacts, as outlined in the All Island TSO Facilitation of Renewables Studies Report. The experience in the SEM is for smaller peaking units to be installed. In particular, the latest peaking units installed on the island (Edenderry) are 55MW each. The planned peaking units in Cahir and Cuilleen[1] are both 98MW. This suggests that a rational investor would choose to construct a significantly smaller unit that the proposed 180MW unit.

Endesa Ireland questions the reasoning the Interconnector was deemed an unsuitable technology choice (Section 5.3). The consultation paper states that it was deemed unsuitable as there is a level of uncertainty as to whether it could supply the last MW of load in all situations. It is unclear what ‘all situations’ means, but if given its literal meaning, it seems to suggest that the BNE must be able to provide black-start capacity. If this is the case, this should therefore be a criterion of the technology selection and the additional costs should be included in the calculation of BNE fixed costs.

Investment Costs

Endesa Ireland proposes that, rather than choosing a theoretical site, as in Section 6.2, the RAs should base cost estimates on actual consented sites on the island. An average of individual cost components associated with these plants, rather than estimations could then be used. It is also submitted that the costs of obtaining planning permission and environmental permits, including environmental studies (e.g., EIS or Appropriate Assessment), should be included with site procurement costs, to fully reflect costs incurred.

[1] All-Island Generation Capacity Statement 2011-2020

The UR consulted in May 2010 on the question of what should be done with NIE Land Bank sites, including the West Belfast site. In February 2011 the UR published a note which indicated that a request for proposals and criteria for selection will be issued, and directing NIAUR to appoint an agent to act on their behalf.[2] On this basis, the site is not currently available to the market so a generator could not currently develop a BNE on the site – it is thus argued not to be a feasible site for a BNE to enter the SEM in 2012. In addition, the UR's Consultation Paper and Update on the land bank sites proposed that criteria that the UR would consider in deciding whether to accept a proposal from a developer would include 'consistency with energy policy'; it is submitted that this would include developing a low CO_2 and NO_x emissions generator which would mitigate against choosing a distillate plant.[3]

Endesa Ireland argues that the cost of fuel tanks for a distillate plant should be included in the investment costs. This is akin to gas connection costs for a dual fuelled station. Endesa Ireland estimate that this cost would be in the region of €800,000-€1,000,000 but propose that the RAs further research this question. Provision for the construction of the tank and provisions for compliance with the Seveso requirements should also be included in EPC costs.

The electrical connection costs proposed in Section 6.3 seem to be low, given Endesa Ireland's experience, although this is difficult to analyse without greater detail; we have only been told that the connection would be at 110kV. Endesa Ireland requests that greater detail is provided in relation to the connection.

The proposal in Section 6.4, which considers a zero cost of water connection is not reflective of real costs. The water connection cost should be revised to include the costs related to increased capacity of the water system necessary to meet the needs of the new power plant and the cost of inspection and maintenance of the pipes. In Endesa Ireland's experience, even with a plant very close to water, existing pipelines would require inspection and maintenance. Depending on the condition of the pipes, the costs associated with the water connection could exceed €200,000.

[2] http://www.uregni.gov.uk/news/view/update_on_the_consultation_on_vacant_sites_within_the_nie_land_bank/

[3] The UR have included the objective of promoting sustainability and security of supply by working with utility companies to take account of the environmental impact of the services they provide in their 2011/12 Forward Work Plan.

Location

The investors in the new and planned peaking units in the SEM have all chosen to locate their plants in Ireland, as set out in Section 4.2 of CEPA's report[4]. This calls into question the location proposed for the 2012 BNE. A rational investor would take into account the taxation regimes in each potential location prior to selecting a site – including how they would apply to energy and capacity payment income for the life of the unit. Given the more favourable tax rates in Ireland, evidence shows a rational investor would choose to locate their plant in Ireland.

Furthermore, the recently proposed TUoS tariffs for 2011/2012 indicate that generator TUoS in NI is significantly higher than that included in the BNE calculation and that these charges are generally higher in NI than in Ireland. The "locational" signal would indicate that Ireland, not Northern Ireland, is the best location to invest in a new generation unit.

Fuel Security Requirements

Endesa Ireland suggests that if the BNE is to be located in Northern Ireland then the fuel-stocking requirements in that jurisdiction should be assumed. While there is an ongoing consultation on the future fuel stocking requirements, early proposals indicated a 5 day requirement. The current actual requirement is dependent on the station; for some stations it is significantly higher than 5 days. It is not appropriate to use the lower fuel stock requirement in Ireland to assess these costs. An average of the actual fuel stock requirements for all units in Northern Ireland or the indicative 5 day requirement should be utilised in the calculation of the BNE fixed costs.

Economic & Financial Parameters

The assumption that the BNE investor is an integrated utility with an investment grade credit rating in the range BBB to A discriminates against smaller market participants – a rational investor is not necessarily an international utility.

With respect to the WACC, detailed in Section 8.3, it is surprising that the RAs believe BNE WACC has decreased from 2011 to 2012. Endesa Ireland considers that the assumptions that the cost of debt has reduced from last year is flawed and considers that the ERP is too low.

[4] Endesa Ireland would note that this report incorrectly states that Endesa Ireland "plans to commission new plant immediately after the closure of the existing units at Great Island and Tarbert." Endesa Ireland will close the existing units AFTER the commissioning of the new units.

In addition, Endesa Ireland believes that the risk free rate for the UK of 1.75% is very low. With the UK inflation target rate of 2%, this rate is negative in real terms. Endesa Ireland also argues that a debt premium of 1.75% is not achievable, and that 2.75% is more appropriate over a 15 year life.

The economic and regulatory risks on the island of Ireland continue to increase, Electricity demand continues to decrease, capacity payments are being whittled away, the future electricity market structure is uncertain with the requirements of Regional Integration and the UK Electricity Market Reform Consultation's proposals,[5] and the incentives for peaking units are insufficient to incentivise new entry. A rational investor would utilise a risk-premium greater than 6%.

Finally, a rational investor in the SEM would take into account the fact that the economic situation on both sides of the border will have an impact on the market returns. Therefore, it would be more appropriate to use a blended WACC, taking into account the costs in both jurisdictions.

Proposed Best New Entrant Peaker for 2012

Another matter of concern is that the choice of distillate as the chosen fuel type means that gas connection costs are not recoverable in the SEM. This has been a gap in the SEM since its establishment and Endesa Ireland considers that it should be resolved urgently, especially in view of the fact that gas units will be key in catering for the intermittent nature of wind. These costs may be absorbed by baseload CCGTs who have historically benefitted from infra-marginal rent, but this may not continue into the future and certainly will not be the case for peaking units.

Further, the selection of distillate as the preferred fuel will result in additional costs being incurred in planning permission and IPPC licence processes which should be included in the BNE fixed costs. ("As stated previously, NIAUR have indicated that any unit to be constructed on one of the land bank sites must be "consistent with energy policy".)

The 'Initial Working Capital (Including Fuel)' listed in Table 9.1 in the summary of costs is not clearly explained. It is said in CEPA's report in Table 7.1 to include the initial fuel charge plus two months' payables. These payables are not set out.

[5] http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

Infra-Marginal Rent
Section 10 discusses the infra-marginal rent to be earned by the BNE and states that the output of the new Directed Contracts (DC) model will be used in for the BNE Decision Paper. Endesa Ireland believes it is crucial that if the new DC model results in an outcome other than zero infra-marginal rent, any modification to the capacity pot inputs should be consulted upon by the RAs.

Ancillary Services
In relation to Ancillary Services, as discussed in Section 11, there are a number of areas where the assumptions made in the paper are unclear or flawed. All generators are required to comply with the Grid Code. Generators that are unable to comply with the Grid Code will incur penalties. The Grid Code requires that all generators provide Ancillary Services. Generators must enter into an Ancillary Service Agreement (ASA) with the TSO in order to receive payment for Ancillary Services provided. The ASA sets out fixed agreed values for provision of these services. If a generator provides services in excess of the agreed values in the ASA, they do not receive payment for the excess provision. If a generator does not provide the services as per the agreed values, they are penalised.

Endesa Ireland has confirmed with the RAs that the reactive power which the proposed BNE technology is capable of providing is 60MVar of leading and lagging reactive power. This means that the unit is not Grid Code compliant. It is not clear whether the unit can operate at full leading 0.93 at Registered Capacity and similarly, when operating at this range whether it can fault ride through for 200ms, which is the Grid Code requirement. Endesa Ireland requests clarification on these points and argues strongly that the BNE should meet all Grid Code requirements or the costs of the "Incentives" for ensuring Grid Code compliance should be included in the fixed costs.

The RAs have stated in response to queries raised by Endesa Ireland that their advising consultants consider that Irish Grid Code Compliance, particularly in terms of leading power factor capability, is expected to be less onerous for smaller units such as the GT 13ET than for larger units. Endesa Ireland requests that the basis for this assumption, and for the requirement actually assumed for this unit be published. Endesa Ireland understands that all units, regardless of size are required to comply with the Grid Code unless they receive derogations, and believes that full Grid Code compliance should be a criterion of selection as BNE. The Irish TSO has indicated they will penalise new builds for non compliance, in particular fault ride through characteristics which also impact on leading power factor capability. Endesa Ireland considers that the inability to meet the reactive power Code Requirements would cost the BNE €181,000 per annum in penalties.

The RAs have also indicated, in response to queries from Endesa Ireland that they have not considered project/site specific elements such as Grid Short-Circuit Power, Grid External Reactance Value and Transformer Reactance Value as it is considered beyond the scope of the BNE calculation to determine any difference in generator costs on account of Grid Code requirements. Endesa Ireland argues, to the contrary, that these elements should be included in the costs of the unit.

The calculation of Ancillary Service payments to the BNE unit is not transparent and seems to neglect the requirement for an ASA. Endesa Ireland has received information from the RAs which seems to suggest that the consultation paper assumes the BNE will be paid for the average of reserve available for every half hour it is running. This is a flawed assumption which overestimates AS income. Endesa Ireland notes that in order to be paid for reserve, a unit must agree a contract with the TSO and will be paid for a fixed agreed value when this value is produced - if a unit provides additional reserve it will not be paid for the extra, and if it does not meet this threshold it will not be paid at all, so the payment received would not be in excess of the agreed fixed value. Endesa Ireland would welcome clarification on this point.

Endesa Ireland has calculated an assumed AS income based on ASA contract values equal to Grid Code requirements (except for Reactive Power for which income is as set out in the Consultation Paper) and, penalties from failure to meet Grid Code Requirements and 4 full MW loss SND events with no notice, which is more appropriate for a newly commissioned peaking unit. This calculation is set out in Appendix A below and estimates that AS income would be €3.05 per kW, rather than €4.41 as assumed in the Consultation Paper – this results in an increase of €9,443,251 in the ACPS. The assumptions used in the calculation and are set out in Appendix A.

There is some ambiguity in the revenue assumption on operating reserve contained in the RAs paper (SEM-11-025) as it seems inconsistent with the CEPA paper. CEPA's paper states that the BNE plant will 'never be used for operating reserve' and that the 'Only AS which therefore appears relevant is the provision of replacement reserve'. However, the RA's paper includes operating reserve and reactive power in Table 11.1 which shows the Ancillary Services payments that the BNE peaker for 2012 would achieve.

Analysis of the assumptions relating to the proposed penalties incurred by the BNE is difficult, as these assumptions are not set out in sufficient detail. For example the number of trips/SND events is not specified in the consultation paper. Follow-up communication with the RAs has clarified that it has been estimated that the BNE has one SND and one Trip Charge. Endesa Ireland's calculations have shown that the current SND charge rate has been assumed, rather than the €70/MW proposed in the 2011/12 consultation on Ancillary Services and Other Systems Charges, as decided in SEM-10-001. In prior BNE decision papers, the RAs have utilised the proposed AS payments. Given this precedent, Endesa Ireland argues that the higher penalty should be included in this calculation.

Capacity Requirement for 2012

It is stated in Section 13.3.2 that the demand forecast will be revisited with TSOs in early Summer 2011. Endesa Ireland requests that if there is to be a change in the demand forecast for the 2012 BNE that the RAs consult with stakeholders.

Conclusion

Endesa Ireland does not consider that all the inputs to the BNE calculation have been accurately assessed in the consultation paper. In particular, we consider that the WACC should be increased to reflect reality, taking into account the all-island situation, fuel storage tank costs should be included, income from Ancillary Services should be reduced and the unit should either be Grid Code Compliant or the resultant penalties should be included in the calculation of fixed costs. We also consider that a rational investor would choose to locate in Ireland, due to the lower TUoS rates and the more favourable taxation regime.

There is little evidence to support a decrease in the WACC from last year. While the WACC is company-specific, Endesa Ireland considers that the cost of debt and the ERP are not reflective of actual market conditions.

Endesa Ireland would also like to note that there are significant fixed costs that generators continue to be unable to recover from the market, including gas connection costs. We urge the SEMC to include these costs in the capacity payment calculations or devise a means by which generators are able to recover these costs from the market.

Endesa Ireland has serious concern about the proposal to reduce the ACPS by 4.62% in 2011. This results in a significant decrease in the capacity pot, compounding the consistent reduction since 2009, for an overall reduction of approximately 18% since Endesa Ireland entered the market. This sends a very poor signal to new investors, particularly where actual fixed costs for existing generation stations have not reduced in line with the reduction in the capacity pot.

The capacity pot is a self-regulating mechanism. If there is excess capacity on the system, the monies will be spread among a larger number of market participants, reducing their incomes and providing insufficient incentive for entry and no incentive for new investment until that investment is needed. It is therefore quite worrying when the capacity pot is being “adjusted” by unexpected means, such as extending the life of the plant, by increasing the provisions for Ancillary Service income for units without a declared ASA value or by manipulating the WACC that is utilised in the calculations.

Appendix A

BNE Paper
EI estimated

Cost Item	Grid Reserve Requirement	Hours Receiving Payments	Estimated Annual Availability	Annual Availability (BNE Paper)	Annual Hourly Rate	Annual Payment (BNE Paper)	BNE Paper (Including GPI Charges)	GPI Compliant estimated Revenue	GPI Compliant (ex RP) estimated
				Provided in BNE Paper					
	MW or MVaR	Hours	(Half Hour)	(Half Hour)	€/MWh	€	€	€	€
Primary Operating Reserve	10	166	3,204	8,760	2.22	9,724	9,724	3,556	3,556
Secondary Operating Reserve	10	166	3,204	24,002	2.13	25,562	25,562	3,412	3,412
Tertiary Operating Reserve 1	15	166	5,126	26,981	1.76	23,743	23,743	4,511	4,511
Tertiary Operating Reserve 2	19	166	6,408	26,981	0.88	11,872	11,872	2,819	2,819
Replacement Reserve Unit Synchronised	*192.5*	166	64,079	26,981	0.2	2,698	2,698	6,408	6,408
Replacement Reserve Unit De-Synchronised	*192.5*	8156	3,139,891	3,136,518	0.51	799,812	799,812	800,672	800,672
Reactive Power (Leading)	76	166	25,326	21,024	0.13	2,733	2,733	3,292	2,733
Reactive Power (Lagging)	119	166	39,713	21,024	0.13	2,733	2,733	5,163	2,733
Total Revenue						**878,877**	**878,877**	**829,834**	**821,378**
Penalties						**30,544**	**211,548**	**53,900**	**234,904**
Total (after penalties allocation)						**848,333**	**667,330**	**775,934**	**586,475**
€ Cost Per KW						4.41	3.47	4.03	3.05

Notes/Assumptions

1) Unit assumed to meet it's minimum MW output requirement for each category of reserve payment in each hour it is synchronised.
2) For "GPI Compliant estimated Revenue" the unit is assumed to be declared and contracted to its GPI required values
3) AVR is assumed to declared "on" (i.e. double RP payments)
4) Assume the unit never mets the running conditions for AS revenues to be scaled down.
5) The Penalties in the "GPI Compliant estimated Revenue" scenario are based on 4 full MW loss SND events with no notice.
6) The GPI penalties for this unit for declaring to 60 MVaR lagging and leading come to €181,004
7) "GPI Compliant (ex RP) estimated Revenue" ASA contract values equal to Grid Code required value, except for Reactive Power which is 60MVaR; includes penalties set out in 5) and 6).