Response by Energia to Single Electricity Market Committee Consultation Paper SEM-12-029

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

19 June 2012

1. General Comments

Energia welcomes this opportunity to respond to the Single Electricity Market (SEM) Committee consultation paper SEM-12-029 and its accompanying appendices on the fixed cost of a Best New Entrant (BNE) peaking plant and capacity requirement for calendar year 2013.

This is a fundamental consultation in the context of the function of capacity payments in the SEM and the role of the capacity mechanism for attracting new investment. This year it is especially important because it follows the Capacity Payments Mechanism (CPM) medium term review and forms the basis for the BNE price that will apply for at least the next 3 years.

Energia's response to the CPM medium term review favoured stabilising the BNE calculation providing that it was done on a realistic and sustainable basis given established market design principles and objectives. Energia had particular concerns regarding the:

- Proposed IMR deduction (based on a formula instead of Plexos modeling) being contrived, theoretically and practically flawed and very damaging to the effective functioning of the CPM.
- Proposed forced outage probability target of 5.91% being artificially low and unattainable in light of the historic evidence and increased plant cycling going forward associated with high wind penetration.
- RA's minded to position of increasing the flattening power factor from 0.35 to 0.5, we considered this poorly justified, contrary to the direction of change required for enhanced market integration, and primarily of benefit to large portfolio players.
- Need for the WACC calculation to reflect that any rational investor locating in Northern Ireland will factor in risk associated with the SEM, and consequently the RoI. We argued that the anomaly in current practice which effectively disregards the all-island nature of the SEM can no longer be ignored, and can be easily and appropriately addressed in the BNE calculation for 2013.

Energia's strong views have not changed in relation to the above, but particularly relevant in the context of the current consultation is the need to:

1. Correctly calculate the WACC reflecting the all island nature of the SEM and the reality of current financing conditions applicable to a forward-looking green-field investment in generation.
2. Correctly calculate the proposed IMR deduction based on a bid price that appropriately incorporates start-up costs, the effects of the carbon price floor and revenues that are TLAF-adjusted.

Before we comment further on these and other specific aspects of the current consultation it is worth briefly considering the context.

The CPM is well understood by banks and investors and is relied upon as a fundamental aspect of the market when evaluating projects[1]. The current turbulent investment climate and ongoing euro-zone crisis (which has even escalated again since July 2011) has depleted the pool of banks active in the single electricity market, North and South, and many of these are increasingly risk-averse. As the overall capacity pot continues to be artificially diminished on an annual basis it becomes increasingly difficult to support any investment (past, present or future) in this market. Based upon existing capacity payments in the SEM we could not justify a peaking investment. We, like others, are having great difficulty in getting investors to believe in the CPM. A key concern is that it is open to subjective and ill-justified annual change by the regulatory authorities (RAs) and is not therefore a practicable vehicle for investment. A related and equally important concern they have is that the capacity pot is calculated based upon some clearly unrealistic assumptions that do not reflect prevailing market structures and conditions.

This is the context in which Energia has consistently stressed the need to calculate the BNE price and capacity requirement on a realistic and plausible basis. The mechanism will only work as intended if payments reflect reality in line with current market conditions. This should not be forgotten despite pressures to suppress the size of the capacity pot during these times of economic hardship when it might appear, on the face of it at least, that there is a relatively generous capacity margin. It is important to note in this respect that:

a) The CPM is vital for cost recovery in tandem with the energy-only market governed by SRMC bidding principles and the BCoP

b) Capacity margin is an imperfect indicator of security of supply, as evidenced by the amber alert in RoI earlier this month. There are also known security of supply issues for Northern Ireland which has experienced amber alerts in the recent past[2].

c) If the BNE is not correctly (realistically and plausibly) calculated now this will invariably increase the enduring perception of regulatory risk associated with the electricity market on the island of Ireland (irrespective of market design post 2016 or reform of ancillary services) and this will raise the cost of capital for new investments on a long term basis (for the next 10 to 15 years), years after the euro crisis has dissipated and economic conditions improve. This would be a very false economy that would not be in the best interests of the consumer.

In the above context the remainder of this response provides detailed comments regarding: (1) weighted average cost of capital (WACC); (2) the carbon price floor; (3) infra-marginal rent (IMR) deduction; and (4) the capacity requirement. We

[1] It is recognised that the CPM plays a vital role in the context of SEM design as the primary source of revenue for generators to recover their fixed costs.

[2] We note that the SEM Committee recently discussed concerns raised in the All Island Capacity Statement 2012-2021 regarding security of supply for Northern Ireland by 2016 and suggested that a Project Team be set up to look at this in more detail (Meeting 52, 29 March 2012 SEMC Minutes, published AIP website).

strongly suggest the need for CEPA and the RAs to use up-to-date information and to validate their assumptions and interpretations of the evidence to provide a realistic and plausible calculation of the BNE price and capacity requirement and thus safeguard the effectiveness and credibility of the capacity mechanism and the regulatory process more generally. Our key conclusions are as follows:

1.1 Key conclusions

WACC:

- The anomaly in current practice which effectively disregards the all-island nature of the SEM can no longer be ignored, and can be easily and suitably addressed in the BNE calculation for 2013 by using a blended mid-range WACC for calculating the BNE price.
- The proposed UK WACC is significantly understated primarily because the cost of debt does not reflect current spreads seen by UK utilities, and the sector risk associated with Northern Ireland, as distinct from the rest of the UK, has not been appropriately accounted for in the debt premium, as supported by evidence in our detailed comments. Nor does the debt premium reflect the increased risk associated with a BNE compared to a regulated network.
- The proposed RoI WACC is significantly understated primarily because it does not reflect properly the country risk premium of European and Irish spreads and does not reflect the increased risk associated with a BNE compared to a regulated network.

Carbon price floor:

- In addition to adjusting the bid price of NI generators in the IMR calculation it is vital that the carbon price floor is incorporated into the cost of fuel stocks for NI generators, and this needs to reflect the rising cost of the carbon price floor from 2013 through 2015 given that the BNE will be fixed for 3 years.

IMR deduction:

- The bid price of the BNE in the IMR calculation does not include start-up costs or the effects of the carbon price floor on the bid costs of NI generators. Nor does it reflect the fact that generator output must be multiplied by the relevant TLAF to calculate energy revenues.
- It is inappropriate not to include start-up costs, especially when such units would not be expected to run in the market earning material infra marginal rents for consecutive trading periods. Start-costs for each trading period should be included in the calculation.
- Given that the carbon price floor will apply to NI generators from April 2013 their bid price should be adjusted accordingly in the calculation, based on the average carbon price floor for 2013, 2014 and 2015 as published on the HRMC website.

- The revenue figures should have the relevant TLAF applied to each unit since the output is multiplied by the TLAF to calculate energy revenues.

Capacity requirement:

- It is unrealistic, as evidenced and acknowledged by the TSOs, to assume in the capacity requirement calculation that generator forced outages are completely independent events. Thus the calculated capacity requirement is systematically understated. We therefore recommend that the RAs ensure this is corrected in the probabilistic analysis carried out by EirGrid for calculating the capacity requirement this year and going forward.
- Historic extreme cold weather events should not be understated. Last year's BNE decision paper seems to suggest that extreme weather events are treated as discountable outliers in the capacity requirement calculation. If this is correct and given the influence of cold weather on peak demand this approach would be inappropriate and would understate the capacity requirement.
- The assumed forced outage probability (FOP) of 5.91% is unrealistic and inappropriate as a target value based on the historic evidence and given increased plant cycling going forward associated with high wind penetration. In light of this we would recommend the RAs consider a more realistic FOP value in the range 8 - 9%.

2. Detailed Comments

The previous section gave a broad overview of Energia's response to SEM-12-029 and its accompanying appendices. In this section we elaborate with detailed comments and relevant evidence to substantiate our views. We have endeavoured to be as comprehensive, comprehensible and constructive as possible but given the complexity and nuanced nature of the issues discussed a meeting with the RAs, CEPA, Energia, and our senior banking contacts would be considerably beneficial to supplement this response and we should be grateful if this can be facilitated.

2.1 Weighted average cost of capital (WACC)

It is fair to say that the factual information provided by CEPA in respect of the cost of capital observables is largely correct, albeit slightly out-of-date; it accords with our own information and that of our banking contacts. However it is the interpretation of this information that really matters for deriving a realistic and plausible cost of capital relevant to a green-field peaking plant investment in the SEM. Setting aside our strong views for the moment that a Single Electricity Market (SEM) WACC is necessary and consistent with the overall design of the SEM, we have a fundamental issue with the *interpretation* of the facts and consistency of approach implied in the consultation paper and in the CEPA report, and this view is shared by our senior banking contacts which are utility specialists with recent significant experience in the Irish market.

Having carefully considered the proposed interpretation of UK and Ireland WACC parameters in the consultation paper we strongly submit that it does not reflect the reality of today's financing world in the relevant context of a forward looking green-field investment in a peaking generator subject to competitive and market constraints. It also deviates without convincing or valid justification from the previous approach adopted by the RAs of using the mid-point of the ranges recommended by CEPA. In addition it is overly reliant upon draft cost of capital determinations for regulated network utilities which themselves have yet to be finalised and are currently open for consultation[3]. This is inappropriate, adds considerable uncertainty to what is actually being consulted upon, and also undermines the CEPA analysis and even questions CEPA's role in the BNE calculation process.

We discuss below key interpretative shortcomings, contradictions and irrelevancies that we have identified in the consultation paper and in the CEPA report and conclude that both UK and RoI WACC calculations are significantly understated as a result. Following this conclusion we strongly urge both CEPA and the RAs to engage with relevant banking contacts and re-assess their interpretation of the facts on that

[3] The proposed WACC parameters for NI directly benchmark the draft NIE price control determination. Furthermore, Page 31 of the CEPA report states that "evidence from the BGN and NIE price reviews may require an update to the BNE WACC parameter ranges". This is despite acknowledgement on page 41 of the CEPA report "that regulators' decisions on the allowed WACC for regulated networks are not direct comparisons".

basis. We also comment in detail on the critical need to recognise and reflect the all island nature of the SEM in the BNE calculation. It is widely recognised, accepted and frankly undeniable that the all island nature of the SEM should be reflected in the cost of capital applied to a BNE peaking plant, regardless of its physical location in NI or RoI. It is also relatively straight forward to appropriately modify the existing approach to accommodate this requirement whilst retaining the established building-block approach to WACC and the CAPM formulation method for ascertaining the cost of equity. In the light of this we strongly suggest the existing anomaly of disregarding the all island nature of the SEM in the BNE cost of capital calculation be addressed now in order to correctly calculate the BNE price, preserve confidence in the CPM and the regulatory process more generally, and to attract much needed future investment in generation at a reasonable cost of capital.

2.1.1 A single electricity market WACC

We note that the consultation paper was inexplicably silent on the question of a single electricity market WACC despite featuring in Annex 3 of the accompanying CEPA report and being acknowledged as an issue to be given further consideration in the CPM Medium Term Review Final Decision (SEM-12-016). We therefore welcome clarification from the recent workshop on 6th June that the RAs are open to the principle of a single electricity market WACC and how it might be implemented. Given its importance it is nonetheless disconcerting that this issue was not covered explicitly in the RA's consultation paper. This omission might naturally give the impression that the SEM Committee is strongly predisposed towards the status quo approach of implementing a jurisdictional specific WACC that effectively disregards the all island nature of the SEM. We strongly submit that the status quo in this regard is patently incorrect and cannot be allowed to continue (for another 3 years+) in light of the evidence and CEPA's assessment that:

- *"…the circumstances of investing in a market that operates across two jurisdictions has relevance as it is the cash-flow risk of the investment which investors will in reality consider"* (p. 69, Annex 3 of CEPA report).

- "*As capacity payments (the BNE's principle revenue stream) are funded on an all-island basis and covered by all-island credit cover arrangements, 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)"* (p. 68, Annex 3 of CEPA report).

Given the inseparable cross-jurisdictional (all-island) cash flows associated with a peaking investment in the SEM, CEPA recommends that a single (blended) WACC approach for calculating the BNE WACC "should be considered further by the RAs", and note their understanding that a "blended all-island WACC will be presented to the SEM Committee as an option for the final consultation paper".

Given the above, and despite the consultation paper being strangely silent on the need for a single electricity market WACC and how this should be implemented, Energia reasonably expects that the SEM Committee will duly consider and implement a single electricity market WACC for the 2013 BNE calculation. The reasons for doing so are compelling:

(1) A single electricity market WACC is wholly consistent with SEM design and the stated fundamental premise of the BNE methodology that the rate of return earned by a new entrant must be sufficient to cover the risk of entering the SEM[4]. The BNE peaking plant derives its revenues from an all island market. The capacity pot is based on an annual calculation of the capacity requirement of the island of Ireland which is inherently impacted by the economic drivers in both NI and RoI. The jurisdictional location of a peaking plant would be irrelevant.

(2) CEPA confirmed that they have not been in discussions with banks as part of their analysis. Financing of a peaker in NI would not be seen as a pure UK benchmark risk. A single electricity market WACC is therefore necessary for the effective functioning of the CPM, and to preserve required confidence in the integrity of the regulatory process to attract capacity at a reasonable cost of capital when needed.

(3) Implementing a single electricity market WACC in the BNE calculation can be easily and suitably achieved by means of the blended WACC approach, as suggested by CEPA. Whether or not this is a methodological change to the way the capacity payment mechanism has historically been set is entirely irrelevant[5]. It is the correct thing to do in light of the evidence and the all island nature of the SEM. This issue was communicated to the RAs and CEPA in the context of last year's BNE calculation. There has been sufficient opportunity to consider it since then which has clearly been done by CEPA as evidenced by Annex 3 of their report.

(4) In terms of implementation it is unclear why a particular question has been raised by CEPA on selecting a point estimate in the context of a blended WACC. It is suggested by CEPA that the RA precedent of adopting the mid-point of the WACC range in previous BNE decisions may no longer be appropriate in this context and that the RAs should instead consider adopting the lower end of the RoI WACC range (which coincidentally largely corresponds to the UK WACC proposed in the RAs report). The risks associated with participation in the SEM cannot be disconnected from the risks of the Irish state (or Northern Ireland for that matter). And to choose the lower end of a range whose risk benchmarks German sovereign bonds incredulously implies that risk associated with

[4] The original SEM BNE methodological decision paper SEM-07-14 states on page 20 that the "[t]he rate of return earned by a new entrant must be sufficient to cover the risk of entering the SEM". This was re-iterated more recently on page 26 of the CPM medium term review consultation paper SEM-10-068.

[5] We do not accept the CEPA view that correcting the existing anomaly by adopting a single WACC approach would constitute "a major methodological change to the way the capacity payment mechanism has historically been set". A single electricity market WACC can be suitably implemented as a simple extension of the existing building-block approach to the WACC. We also do not consider the issue of methodological change even relevant in the context of an error that has persisted since the start of the SEM and that been clearly brought to the attention of the RAs by Energia and other market participants in the context of last year's BNE process and the CPM medium term review.

participation in the SEM should be priced closer to the cost of finance faced by Germany than that of the Irish state.

(5) The blended weighting proposed by CEPA is 70% RoI and 30% NI, based on the 2010 GCS peak capacity in each individual jurisdiction rounded to the nearest 10%. Consideration should be given to the use of demand as a factor for establishing the weightings, (75% RoI / 25% NI). Demand better reflects the revenue contributing to the capacity pot and therefore risk.

2.1.2 UK WACC Parameters

Element	2012	2013 Low	2013 Mid	2013 High	2013 RA Proposed
Risk Free Rate	1.75%	1.50%	1.75%	2.00%	2.00%
Debt Premium	2.00%	1.75%	2.25%	2.75%	1.75%
Cost of Debt	**3.75%**	**3.25%**	**4.00%**	**4.75%**	**3.75%**
Equity Risk Premium	4.75%	4.50%	4.75%	5.00%	4.80%
Equity Beta	1.25	1.20	1.25	1.30	1.25
Post Tax Cost of Equity	**7.70%**	**6.90%**	**7.70%**	**8.50%**	**8.00%**
Taxation	26.00%	24.00%	24.00%	24.00%	24.00%
Pre Tax Cost of Equity	10.41%	9.08%	10.13%	11.18%	10.53%
Gearing	60%	60%	60%	60%	60%
Pre Tax WACC	**6.41%**	**5.58%**	**6.45%**	**7.32%**	**6.46%**

Table 1: CEPA and RA's proposed UK WACC parameters

The RA's have interpreted the analysis provided by CEPA and proposed a cost of debt ranging between 3.25% and 4.75% (incorporating a Risk Free Rate (RFR) of between 1.50% - 2.0% and a Debt Premium (DP) of between 1.75% - 2.75%). Proposing cost of debt at **3.75%** (incorporating a RFR of 2.0% and a debt premium of 1.75%).

The total cost of debt at 3.75% is implausibly low because it reflects a debt premium of only 1.75%, the low end of CEPA's range, benchmarked against NIE's draft determination of 1.2% debt premium. We strongly consider this inappropriate for the reasons outlined below.

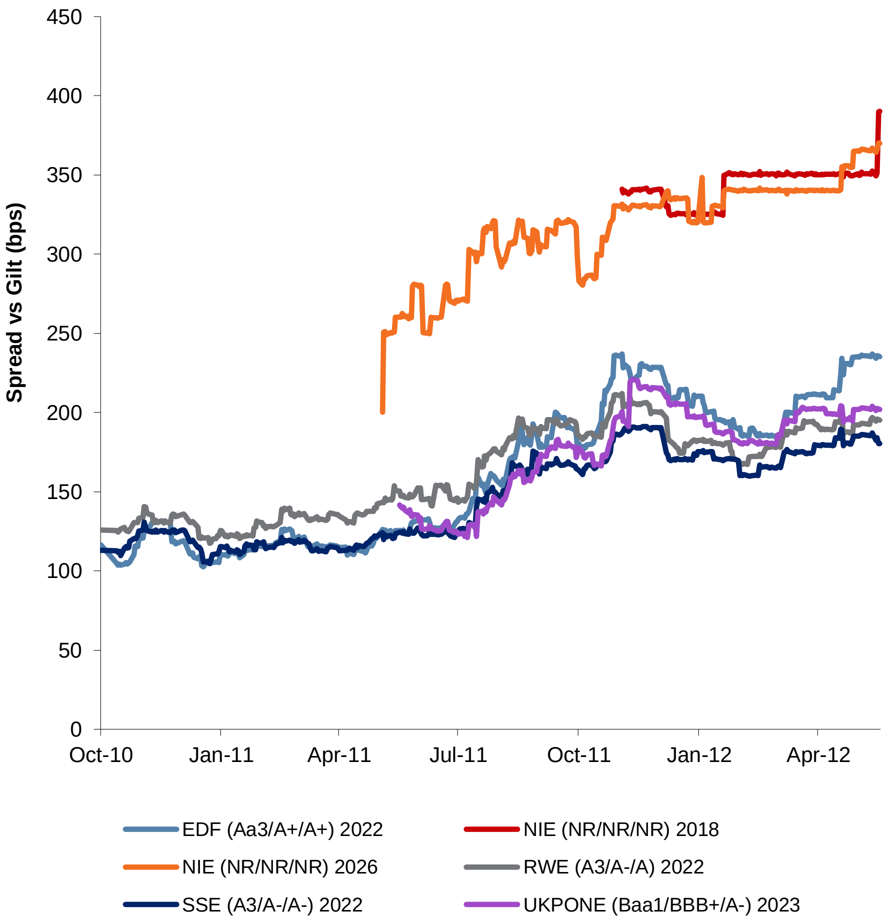
The consultation states that the peaking investment should reflect a forward looking cost of debt: "The notional BNE will be financed by entirely new debt and equity taken out at current costs" (page 41 of CEPA report). NIE's cost of debt in the draft determination reflects historic debt secured at relatively favourable fixed rates completely unachievable in today's environment.

It is acknowledged on page 33 of the consultation paper with reference to the debt premium assumed in the NIE Draft Determination of 1.2% that the lower end of CEPA's range i.e. 1.75% is appropriate for a BNE given that "…the T&D business is regulated and therefore the BNE would be unable to obtain such a low debt premium". The stated uplift of 50bps versus T&D therefore reflects only the higher risk associated with a peaker versus that of a regulated network utility, rather than that the drivers should include the current cost of new debt including an NI premium and a peaking plant premium.

One can see from the analysis of spreads below that the range for partially regulated UK vertically intergraded utilities is 1.64% – 1.89%, over the last twelve months (1.8% - 2.35% at 16th June 2012) and does not incorporate any additional NI risk or the risk of a peaking asset. The midpoint of the UK spreads is 1.78% for the twelve month average and 2.03% at 16th June 2012.

Further to this there is a NI risk premium; this is clearly evidenced through the trading spreads of NI utility bonds. One can see from the Bloomberg analysis in Figure 1 below that the NIE Bond and PNG bond both trade at a premium of on average 1.30% over the last twelve months if one considers the midpoint of UK utilities as a fair comparison with average spreads of 1.78% as identified in the analysis.

Figure 1: Trading spreads of utility bonds (source: Bloomberg)



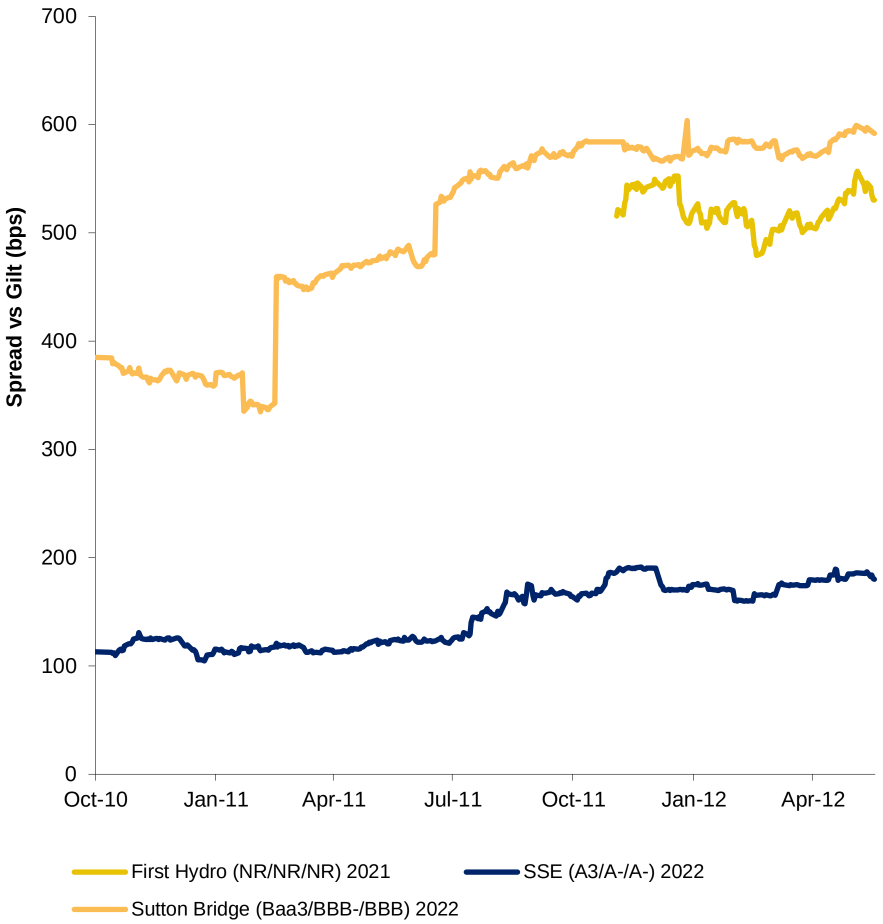
	UK / NI Corporate Bond Spreads vs. Gilt				
	Apr - Jun 12	**Apr - Jun 11**	**Change**	**12 Mths - Jun 12**	**16th June 12**
EDF	223	118	105	189	**235**
SSE	181	118	63	164	**180**
RWE	192	139	53	181	**195**
UKPONE	201	141	60	177	**202**
Average UK	**199**	**129**	**70**	**178**	**203**
NIE	351	250	101	319	**370**
PNG	308	236	73	297	**320**
Average NI	**330**	**243**	**87**	**308**	**345**
Variance	131	114	17	**130**	**142**

Table 2: Trading spreads of utility bonds (source: Bloomberg)

In addition to the NI country premium, there is an asset type premium that a peaker would attract for new debt which can be evidenced by comparison of similar assets in the UK against UK infrastructural asset spreads.

An example of such a spread differential has been extrapolated from analysis of SSE (A-rated partially regulated) bond spreads against the spreads of Sutton Bridge (BBB rated) and First Hydro (NR). In Figure 2 below SSE trades at circa 1.64% over the past twelve months above the gilt with both First Hydro and Sutton Bridge trading on average for the same period at 5.43%. The asset type risk and rating strength can therefore be extrapolated at **3.79%.** This represents comparable assets in the UK with the exception that a peaker in Ireland would be receiving the vast majority of its income from a wholly regulated revenue stream whereas the UK utilities identified receive only part of their revenues from a regulated base, and in the case of First Hydro from a contracted source. For this reason it would be fair to assume that a proportion of this debt premium uplift may not apply. Energia propose a reduction in the range of 25% - 50% adding a debt premium for the asset type of **1.90%** Low and **2.84%** High.

Figure 2: UK corporate bond spreads (source: Bloomberg)



	UK Corporate Bond Spreads				
	Apr - Jun 12	Apr - Jun 11	Change	12 Mths - Jun 12	16th June 12
First Hydro	524	N/A	N/A	522	530
Sutton Bridge	584	471	113	564	592
Average	554	471	83	543	561
SSE	181	118	63	164	180
Variance	373	353	20	379	381

Table 3: UK corporate bond spreads (source: Bloomberg)

In summary the Debt Premium according to Energia's analysis for a new peaking plant in NI with new debt and a parent of BBB investment rating would range between **4.84% - 6.03%** (UK partly regulated utilities range 1.64% - 1.89% + NI premium 1.30% + peaker premium 1.94% - 2.84%). Applying this premium to the RFR range of 1.50% - 2.00% proposed by the RA's gives a total cost of debt range of **6.34% - 8.03%.** Applying the same methodology as previous consultations and applying a midpoint calculation, the midpoint of the debt range would be **7.19%.** We next consider the cost of equity.

Table 4: Current equity expectations in the UK (source: Bloomberg)

	Cost of Equity	Risk free rate	Equity risk premium
SSE	7.60%	1.70%	6.00%
Centrica	8.50%	1.70%	6.80%

Table 4 above outlines the current equity expectations in the UK. One can see that the post-tax cost of equity ranges between 7.60% and 8.50%, with an ERP ranging from 6.0% - 6.8%. The midpoint on the cost of equity results in a post-tax cost of equity for NI of 9.75%, 1.75% higher than the proposed cost of equity outlined by CEPA and proposed by the RA's.

In summary the updated proposed Energia pre-tax WACC applicable for the RoI should range between 8.54% and 10.35% with a mid-point of **9.44%** adopted.

Element	2012	2013 RA Proposed	2013 Energia Proposed	2013 Low	2013 High
Risk Free Rate	1.75%	2.00%	1.75%	1.50%	2.00%
Country Risk Premium			1.30%	1.30%	1.30%
Debt Premium UK	2.00%	1.75%	1.77%	1.64%	1.89%
Debt Premium Peaker			2.37%	1.90%	2.84%
Cost of Debt	**3.75%**	**3.75%**	**7.19%**	**6.34%**	**8.03%**
Equity Risk Premium	4.75%	4.80%	6.40%	6.00%	6.80%
Equity Beta	1.25	1.25	1.25	1.25	1.25
Post Tax Cost of Equity	**7.70%**	**8.00%**	**9.75%**	**9.00%**	**10.50%**
Taxation	26.00%	24.00%	24.00%	24.00%	24.00%
Pre Tax Cost of Equity	10.41%	10.53%	12.83%	11.85%	13.82%
Gearing	60.00%	60.00%	60.00%	60.00%	60.00%
Pre Tax WACC	**6.41%**	**6.46%**	**9.44%**	**8.54%**	**10.35%**

Table 5: Energia's proposed UK WACC parameters

2.1.3 RoI WACC Parameters

Element	2012	2013 Low	2013 Mid	2013 High	2013 RA Proposed
Risk Free Rate	5.50%				
Debt Premium	2.00%				
Cost of Debt	**7.50%**	**3.50%**	**6.00%**	**8.50%**	**6.00%**
Equity Risk Premium	4.75%	4.50%	4.75%	5.00%	4.75%
Equity Beta	1.25	1.20	1.25	1.30	1.25
Post Tax Cost of Equity	**11.35%**	**7.90%**	**10.70%**	**13.50%**	**10.70%**
Taxation	12.50%	12.50%	12.50%	12.50%	12.50%
Pre Tax Cost of Equity	12.93%	9.03%	12.23%	15.43%	12.23%
Gearing	60%	60%	60%	60%	60%
Pre Tax WACC	**9.67%**	**5.71%**	**8.49%**	**11.27%**	**8.49%**

Table 6: CEPA and RA's proposed RoI WACC parameters

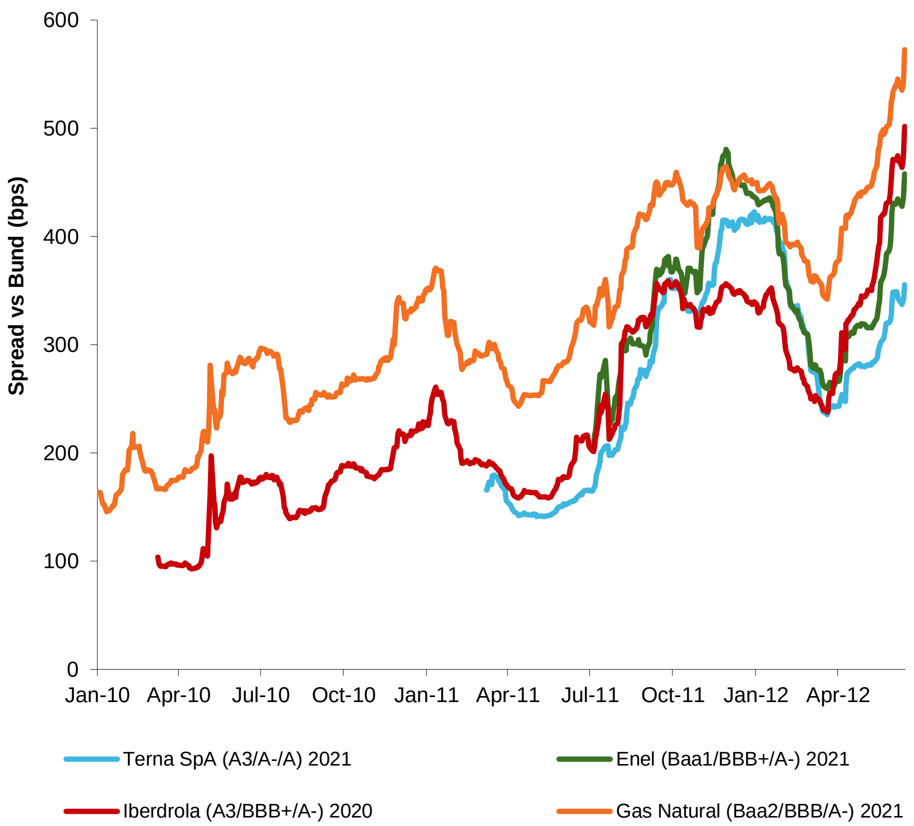
Based on CEPA's interpretation and methodology which deviates from last year, CEPA have proposed a cost of debt ranging between 3.50% and 8.50% (incorporating a Risk Free Rate (RFR) and a Debt Premium (DP)) and the RAs have proposed the midpoint of this range. In arriving at this assumption CEPA and the RA's have used a combination of two methodologies in deriving the cost of debt.

Methodology 1: This proposed approach is in line with last year's BNE determination. CEPA apply an Irish Country Risk Premium (CRP) range of 2.0% - 6.0% and incorporate this into the RFR. This is essentially taking the Euro-zone RFR (0.5% - 1.0%) together with the CRP resulting in an Irish RFR of **2.5% - 7.0%.** In addition to the RFR cost of debt a Debt Premium has been estimated by CEPA at 2.0% - 2.5% resulting in an overall cost of debt of **4.5% - 9.5%.** The midpoint of this range is **7.0%** which is below last year's determination of **7.5%** at a time when market conditions have not improved and such a position would be unachievable as will be discussed later when reviewing the debt premium and up-to-date pricing. This methodology in Energia's opinion better reflects investors views of the Irish market with the country risk premium included within an adjusted Euro-zone risk free rate.

Methodology 2: This proposed approach provides for the Country Risk Premium being incorporated into the Debt Premium only. Using the same Euro-zone RFR of 0.5% - 1.0% (based on German Sovereign Bonds) and adding the previously mentioned debt premium of 2.0% - 2.5% plus a Country Risk Premium of 1.0% - 2.0% (sourced from evidence of Irish and other European utility 'peripheral' debt) resulting in a cost of debt range of **3.5% - 5.5%.** The application of this methodology does not appropriately reflect the Country Risk Premium associated with Irish debt. The midpoint range in this methodology is **4.5%** this is 40% below last year's determination of 7.5% and is completely unrealistic, investors would not see this pricing as an achievable level and would not support such a low level of debt cost.

CEPA propose and recommend a cost of debt range of between **3.5% - 8.5%** ***(resulting in an interpreted midpoint of 6.0% proposed by the RA's)*** for the application of the current BNE WACC calculation. CEPA state that the bottom end of the range reflects evidence from recent Euro-zone corporate borrowing costs, including 'periphery' Euro-zone corporate utility debt currently trading at wider spreads than the cost of debt for generic Euro-zone corporate bond utilities. The data below graphed in Figure 3 (sourced from Bloomberg) shows the spread of 'periphery' corporate utility bonds with similar maturity tracked against the German bund. This reflects a debt premium over the bund ranging between 3.55% - 5.73% (as at 16th June 2012) with an average spread over the past twelve months ranging between 3.09% - 4.17% with the range reflecting A-rated utilities. This factually evidences that the low end of the range identified by CEPA is incorrect. The underlying debt premium for 'peripheral' debt should be **3.59% - 5.17%** (assuming a RFR of German bonds ranging between (0.5% - 1.0%) for an **A-rated utility** in the Euro-zone as opposed to a BBB rated utility and an investment in a peaking plant. The average increase over the last 12 months has been circa 2.0% which is reflective of market conditions and should be reflected in the cost of debt assumed by the RA's

Figure 3: Spread of 'periphery' corporate utility bonds vs. German Bund



	EURO-Zone Corporate Bond Spreads vs. Bund				
	Apr - Jun 12	Apr - Jun 11	Change	12 Mths - Jun 12	16th June 12
Enel	360	N/A	N/A	352	458
Gas Natural	482	269	213	417	573
Terna	305	146	159	309	355
Iberdrola	397	168	229	319	502
Average	**386**	**194**	**191**	**349**	**472**

Table 7: Spread of 'periphery' corporate utility bonds vs. German Bund

The real cost of debt in Ireland is further evidenced by the spread on the Irish 10yr government bonds vs. Bund together with the ESB bond. Table 8 below shows the trading spreads of the Irish sovereign bond currently at 5.91% above the bund, with the twelve month average trading at 6.46%, this essentially should be the cheapest level of debt that a utility could raise funds in Ireland. This is further supported by the bond spreads for ESB (infrastructure regulated asset) that align with the Irish government bond at spreads of 7.89% as at the 16th June and on average 6.29% over the past twelve months. When compared to other 'peripheral' Euro-zone utilities with A-rated infrastructural asset credentials, the outcome for Irish utilities is at the high end of the range.

	Govt + Corporate Bond Spreads "Ireland"				
	Apr - Jun 12	Apr - Jun 11	Change	12 Mths - Jun 12	16th June 12
Gov't Bond	565	751	(186)	646	591
ESB Bond	668	389	279	629	789
Average	617	570	47	637	690

Table 8: Government and corporate bond spreads in Ireland (source: Bloomberg)

In Energia's view the debt premium / country risk for RoI should range between the midpoint of Euro-zone 'peripheral' debt and spreads of Irish government and ESB bonds over the historic twelve months **3.63% - 6.37%** *(Low = midpoint of 3.09% - 4.17% = **3.63%**, High = average of ESB and Irish government bond spreads 6.29% - 6.46% = **6.37%**)*.

The above analysis excludes the debt premium associated with a peaking plant rather than partially regulated infrastructure assets, as such the cost to a BNE peaker (new debt) should reflect the realistic cost of debt in Ireland for such an asset.

The premium that a peaker would attract can be evidenced by comparison of similar assets in the UK against UK infrastructural asset spreads as outlined previously for the UK WACC whereby the debt premium associated with a peaking plant is calculated at 1.9% - 2.84%.

In summary as outlined below the cost of debt, according to Energia analysis for a new peaking plant in RoI with new debt and a parent of BBB investment rating would range between **6.03% - 10.21%,** applying the same methodology as last year's BNE process for country risk and applying a debt premium reflective of the asset type. Using a mid-point calculation on this the Energia RoI Cost of debt would be 8.12%**.** This is 0.62% above last year's determination of 7.5% and reflects change in market conditions experienced over the last twelve months. We next consider the RoI cost of equity.

Table 9: Current Euro-zone equity expectations

	Cost of Equity	Risk Free Rate	Equity Risk Premium
Enel	14.20%	5.40%	8.80%
Endesa	14.20%	6.90%	7.30%
Gas Natural	15.10%	6.90%	8.30%
EDP	13.70%	10.50%	3.10%

Source: Bloomberg as of 15th June 2012

Table 9 above outlines the current equity expectations in each of the entities including 'peripheral' Euro-zone countries. One can see that the post-tax cost of equity ranges between 13.70% and 15.10%., this is a combination of ERP ranging from 3.10% - 13.60% and a RFR of 5.40% - 10.50%. For the purposes of the calculation of the cost of Equity the CRP has been included as this better reflects the equity requirement of investors in other Euro-zone countries. The midpoint on the post-tax cost of equity is 15.81%, 4.46% higher than the proposed cost of equity outlined by CEPA and proposed by the RA's. This market information is more relevant in setting the equity costs for an RoI peaking plant.

In summary the updated proposed Energia pre-tax WACC applicable for the RoI should range between 9.68% and 14.52% with a mid-point of **12.10%** adopted.

Element	2012	2013 RA Proposed	2013 Energia Proposed (mid)	2013 Low	2013 High
Risk Free Rate	5.50%		0.75%	0.50%	1.00%
Country Risk Premium			5.00%	3.63%	6.37%
Debt Premium	2.00%		2.37%	1.90%	2.84%
Cost of Debt	**7.50%**	**6.00%**	**8.12%**	**6.03%**	**10.21%**
Equity Risk Premium	4.75%	4.75%	8.05%	7.30%	8.80%
Equity Beta	1.25	1.25	1.25	1.25	1.25
Post Tax Cost of Equity	**11.35%**	**10.70%**	**15.81%**	**13.26%**	**18.37%**
Taxation	12.50%	12.50%	12.50%	12.50%	12.50%
Pre Tax Cost of Equity	12.93%	12.23%	18.07%	15.15%	21.00%
Gearing	60%	60%	60%	60%	60%
Pre Tax WACC	**9.67%**	**8.49%**	**12.10%**	**9.68%**	**14.52%**

Table 10: Energia's proposed RoI WACC parameters

2.1.4 WACC Validation

We note that when CEPA first became involved in the BNE process in 2009 they carried out an extensive investigation of the building blocks of WACC and provided a range within which they believed the appropriate WACC should lie. We also observe that in 2009 the RAs attended a meeting that CEPA held with their banking contacts on the financing costs of similar types of investment in the UK and Ireland. The discussions and information shared at these meetings we understand was a useful cross check to the CEPA analysis and validated the assumptions used. As confirmed during the recent RA workshop on 6th June 2012 this important exercise has not been repeated or updated since. Given the shift change in financial markets and financing conditions in recent years (there has even been a marked escalation of the sovereign debt and euro crisis since July 2011) we would urge the RAs and CEPA to be strongly guided by banking input before concluding this year's BNE determination process, especially when this will form the basis for the BNE price for at least the next three years. We welcome clarification at the recent workshop that the RAs and CEPA are willing to engage with our banking contacts and we will ensure this can be facilitated. We strongly suggest that such a forum also be used to elicit banker views on the need and design of a single electricity market WACC for a peaking investment in the SEM.

2.2 Carbon price floor

A carbon price floor will be introduced UK-wide from 1st April 2013. Supplies of fossil fuels used in most forms of electricity generation will become liable either to the climate change levy (CCL) or fuel duty from that date. Such supplies will be charged at the relevant carbon price support rate. Carbon price support rates are now published by HMRC and are available online @ http://www.hmrc.gov.uk/. Rates have been set for 2013/14 and 2014/15 (commencing 1 April each year) which are £4.94/Te and £9.55/Te, and an indicative rate of £12.06 has been set for 2015/16.

The carbon price floor will apply to fuel costs (distillate and gas) of peaking generators located in Northern Ireland. This has not been accounted for in the BNE 2013 consultation, as confirmed at the recent workshop of 6th June and this needs to be corrected in the fuel cost assumptions and bid price, noting that a three year average carbon price floor should be calculated based on published rates for 2013, 2014 and 2015.

2.3 IMR deduction

In the information note published by the RA's on 8th June 2012 it is confirmed that the average bid price of peaking units operating in the SEM (as of 31st March 2012) has been used to proxy the bid price of the BNE, as per the formula below.

$$Weighted\ Av\ Bid\ Price = \frac{No\ Load + P_1Q_1 + P_2(Q_2 - Q_1) + \cdots}{\max capacity}$$

The above bid price formula does not include start-up costs. This is a material omission, especially given the likelihood that a peaking unit will only run for one trading period over which it will have to recover its full start-up costs. In the context of the revised IMR methodology that unrealistically assumes a peaking plant will earn material infra-marginal rents for 8 hours per annum it is inconceivable that this will be accumulated over consecutive trading periods. Thus it must be assumed that such a unit will start up 16 times cumulating the 8 hours assumed running time in the market over which it is assumed to earn infra-marginal rents. The above calculation does not include these start-up costs and we strongly suggest that this needs to be corrected to properly calculate the IMR as conceived by the revised methodology.

It should also be noted that the Carbon Price Floor (applicable to generators in Northern Ireland from April 2013) is not factored into the above calculation, and this needs to be corrected.

Finally, IMR revenues should be TLAF-adjusted. The revenue figures should have the relevant TLAF applied to each unit since the output is multiplied by the TLAF to calculate energy revenues.

2.4 Capacity requirement

In response to last year's BNE consultation Energia contended that the calculated capacity requirement was materially and systematically understated for three main reasons, namely because:

1. It assumes that generator forced outages are completely independent events which is not realistic.
2. Extreme cold weather events seem to be treated as discountable outliers in peak demand projections.
3. Assumed plant availability is inappropriately projected from expected improvements – instead this should be based on historical data on an all-island basis.

Regarding point 1 above last year's BNE decision paper SEM-11-059 did not address the concerns raised or give any recognition to the risk of common mode failure that Energia identified with reference to cold weather events and computer viruses. Perhaps this reflects a misunderstanding that common mode failure is only considered a risk during extreme cold weather events and decision paper SEM-11-059 dismissed such events as being 'atypical'. We note that the TSOs do not seem to share the view that the risk of common mode failure or sympathetic tripping can be written off as being atypical. This is illustrated by the following extract of the harmonised other system charges consultation published by the TSOs on 3rd April 2012: "There were six events during the tariff year 2010-2011 where, following a large drop in load, another unit dropped significant load, causing a further reduction in frequency. These events are of serious concern…" It should also be noted that in the All-Island Generation Capacity Statement for 2011-2020 the TSOs acknowledge that in reality it is not entirely true that forced outage probability is the same at all times and not linked to the outages of other generators, and as a result this may lead to an overestimation of system adequacy. Given the evidence and expressed concerns it would be imprudent to continue assuming (incorrectly) that generator forced outage probability is the same at all times and completely independent from the outage of other generators in the capacity requirement calculation because this invariably understates the capacity requirement. We would recommend that the RAs ensure this is corrected in the probabilistic analysis carried out by EirGrid for calculating the capacity requirement this year and going forward.

In terms of point 2 above, last year's BNE decision paper referenced the average cold spell (ACS) adjustment in the peak demand calculation and stated on page 36 that: "This analysis enables the ACS adjusted winter peaks to be compared on the same level as extreme weather conditions are therefore taken out of the equation". It is not clear what this means but it does seem to suggest that extreme weather events are treated as discountable outliers in the capacity requirement calculation. Given the influence of cold weather on peak demand (nearly all peak demand records are driven by cold weather events rather than economic conditions) this approach would be entirely inappropriate and would imprudently understate the capacity requirement.

In relation to point 3 above Energia welcomes recognition from the RAs that the previous FOP value used in the CPM calculation of 4.23% was overly optimistic. This is recognition that the CPM has been undervalued since the start of the SEM. However we maintain that the proposed 5.91% FOP value to be used in the BNE 2013 calculation is not well founded in practice or justifiable as a target value, based on forced outage rates observable in practice or achievable going forward given increased plant cycling associated with high wind penetration. In light of this we strongly recommend that the RAs consider a more realistic FOP value in the range 8 - 9%.