Response by Energia to Single Electricity Market Committee Consultation Paper SEM/15/032

Fixed Cost of Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Trading Year 2016

22nd June 2015

The calculation of the Annual Capacity Payment Sum (ACPS) is fundamental to the correct operation of the SEM. Its design, in conjunction with the Bidding Code of Practice is to reduce price volatility and ensure the appropriate remuneration of generators. This year's consultation has great significance as *"the value for 2016 has been re-opened for ground- up calculation"*[1] and will form the basis for the BNE price that will apply until the inception of ISEM. This gives the RAs the opportunity to correct previous errors which have led to a consistent underestimation of the ACPS.

During previous consultations on ACPS Energia has advocated the merits of a stable and consistent approach to the BNE calculation and highlighted the damage that regulatory uncertainty associated with inaccurate and unjustifiable assumptions can have in a market where all generator revenues are subject to far reaching regulation.

The current consultation results in an unstable reduction in the ACPS by cherry picking inappropriate benchmarks and persisting with flawed calculations. This appears to have been conducted without due consideration to the implications that such actions will have on the sector which conflicts with the CER's statutory duty to have regard to the need to ensure that licence holders are capable of financing their undertakings.

In analysing the consultation and preparing this response, Energia have been supported by Viridian Group[2], RBS's Preliminary Ratings considerations for a new BNE peaking plant, Frontier Economics and Poyry. Below is a synopsis of the most glaring inaccuracies noted in the CEPA analysis:

- The use of an unrealistic and discriminatory WACC calculated using low metrics
- The assumption that the electricity system will be operated to an 8 hour LOLE does not reflect actual practices of TSOs or regulators
- The 7,070MW capacity requirement determined represents a very small plant margin of only 399MW relative to the median TER Peak for 2016. This is equivalent to a single CCGT and would not be acceptable to RAs, TSOs and politicians.
- Concerns that CEPA may have been heavily influenced by the SEMC in writing its report. This is clearly evidenced where CEPA state "based on guidance from the SEM Committee, we have retained a gearing assumption of 60%..."[3]. It is vital for the sector that CEPA should be permitted to make conclusions on an entirely independent basis.

The ACPS proposed in this paper constitutes a 19% drop on the 2015 figure and is 16% below the average (since 2007). The most significant contributory factor of this is an unfathomably low WACC for a BNE peaking plant located in NI of 4.46% (ROI: 4.52%) this represents c32% (ROI: c50%) reduction from the WACC applied in the 2013 BNE decision. Our analysis, in conjunction with Frontier Economics shows a myriad of incorrect assumptions and deviations from best practice in calculating the WACC. A summary of our main findings on WACC are as follows:

- The dramatic downturn in generation markets since the parameters (WACC) of the 2013 calculation were set has resulted in an increased risk premium.

[1] SEM-15-032, page 3
[2] Viridian Group provide services to Energia in respect of Corporate Finance and Treasury.
[3] 5.2.1 of CEPA report

- The assumption that an investor will be investment grade vertically integrated utility effectively precludes entities with a lower credit rating from investing
- The proposed WACC levels are significantly below those recently proposed for SONI Ltd in April '15 of 5.42% pre-tax real (CEPA 4.46%). This was proposed by NIAUR for a 100% NI regulated business with lower market and finical risks than a BNE peaker
- The cost of debt analysis and proposal presented by CEPA is manifestly biased towards network regulated assets
- In its calculation of WACC CEPA incorrectly use the inflation metric RPI instead of CPI. This has a material effect in determining the real cost of debt.
- The debt yield information used is now out of date. Debt yields are cyclical and are influenced by many ongoing economic and political factors
- Gearing at 60% is inappropriate. (Moody's gearing of 20-35% is the indicative level to meet BBB)
- As outlined in Frontier Economics report, a Total Market Return of 7.1% for NI and 6.8% for ROI is more appropriate based on recent regulatory evidence

Energia's observation's on the inappropriate nature of the benchmarks used in the CEPA analysis are confirmed by RBS's Preliminary Ratings considerations for a new BNE peaking plant]. RBS's views are based on real world experience of financing utilities.

> *"Without the scale, geographical diversification and substantial EBITDA contribution from regulated networks, a generation & supply utility operating solely in the Island of Ireland market is unlikely to be rated "investment grade" with the gearing levels / capital structure proposed by CEPA / the Regulatory Authorities*
>
> - *Utilities referred to in the paper (p.53) and rated investment grade in EMEA benefit from scale, diversification and regulated network cash flow advantages which largely drive their investment grade rating. None of these characteristics would benefit the credit profile of the assumed benchmark greenfield plant*
>
> - *All of the referenced integrated utilities maintain gearing significantly below 60%; their ratings are based on the actual leverage rather than an "optimised" capital structure as referred to in the paper.*
>
> *As such, the capital structure and rating assumptions put forward in the CEPA paper would appropriately remunerate a hypothetical integrated utility group rather than the assumed benchmark greenfield plant's risk profile at the asset level*
>
> - *When making an investment decision, an integrated utility investor would themselves likely consider the risk profile of the stand-alone project – rather than the group's risk profile – to determine an appropriate return / remuneration on their capital."*

Capacity Requirement

The capacity requirement has been materially and systematically understated now and in previous ACPS decisions. The Capacity Requirement determined (7,070MW) represents a very small margin of only 399MW[4] relative to the median TER Peak for 2016 and 538MW against the median Transmission Peak.

[4] See Section 2 for detailed calculation

The inadequacy of the margin resulting from a Capacity Requirement of 7,070MW is stark when one considers that it represents the capacity of a single CCGT. In contrast Eirgrid's most recent Generator Capacity Standard (GCS) indicates the capacity needed to meet the required security standard is in excess of 8000W.

Analysis of the last three years of the CPM reveals that a far higher security standard has been maintained with the consequence that the capacity requirement has been underestimated and IMR earned by a theoretical BNE investor has been considerably over estimated. Any 'ground up calculation' must address this inconsistency to ensure confidence in the regulatory regime.

Poyry carried out a review of the historical GCS against Capacity interventions made by the TSOs. It is clear that interventions have been made to target average security standard greater than the Generation Security Standard (GSS), the most recent intervention being made in relation to the Ballylumford units. Poyry concluded that recent and historical evidence of the approach taken to generation adequacy implied that, the stated unconstrained load loss level for Ireland and NI is not reflective of the actual target of the System Operators and is significantly more cautious. Should the SEMC choose not to review the LOLE being used in the calculation of ACPS, it will further call into question the analysis and basis on which the Ballylumford contract was awarded to AES in 2014.

Infra-Marginal Rent Deduction

The IMR calculation is predicated on the idea that a BNE plant would expect to earn revenues to contribute to the recovery of its fixed costs when the market is at equilibrium. In reality, the calculation is flawed as the IMR is assumed to be at the equilibrium whereas the available capacity in the market is not. The result is a calculation that is divorced from reality in a market where PCAP has been reached only once since 2007 with a BNE unlikely to receive any IMR. As Poyry note:

> *"Over time this over-estimation of the IMR reduction means that generators will be systematically under-paid by the CPM compared the stated intention – i.e. that annual capacity payments should be targeted at a level that allows full recovery of the fixed costs of the BNE plant."*

Poyry then continue to make the most critical commentary on the IMR and capacity requirement:

> *"This combination of an over-estimation of the IMR by the RAs and the targeting of a higher security standard by the SOs means that, in effect, the SOs are achieving a higher level of system security than the RAs are prepared to pay for."*

Recommendations

This response provides evidence that the consultation paper is flawed and inaccurate in many material respects. The only rational solution is a genuine re-opening of the ACPS for ground–up calculation of the BNE, the capacity requirement and WACC, as we have evidenced in this report. If this is not possible in the time available, the 2016 ACPS should be set equal to the 2015 ACPS, whilst a full and accurate re-calculation is made for 2017.

1. Introduction

Energia welcomes this opportunity to respond to the Single Electricity Market (SEM) Committee consultation paper and its accompanying appendices on the 'Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum for the Trading Year 2016'.

This consultation is fundamental to the correct operation of the market and the appropriate remuneration of generators in the SEM. This year's consultation has great significance as *"the value for 2016 has been re-opened for ground- up calculation"*[9] and will form the basis for the Best New Entrant (BNE) price that will apply until the inception of ISEM.

The RAs should focus on the accurate and appropriate application of methods to determine the capacity requirement and the cost of a BNE, as opposed to the result of the calculations. Re-opening the process for a ground-up calculation gives the RAs the opportunity to correct previous errors which have led to a consistent underestimation of the Annual Capacity Payment Sum (ACPS).

The current consultation gives a drastic reduction in the ACPS by cherry picking inappropriate benchmarks and persists with clearly flawed methods for the calculation of costs, revenues and the capacity requirement. This appears to have been conducted without due consideration to the wider implications that such actions will have on the sector.

Energia also endorses the response of the Electricity Association of Ireland (EAI) to this consultation, including the appended independent reports of Frontier Economics and Poyry.

Capacity Payment Mechanism

Tight capacity margins and a foreseen deterioration in this situation characterised the SEM at its inception. Historical underinvestment in capacity and infrastructure coupled with a growing economy meant new capacity was required and in an energy only market, such capacity would need to be incentivised through a capacity market. The preferred design was a capacity payment mechanism based on the fixed cost of a best new entrant peaking plant and capacity requirement determining the Annual Capacity Payment Sum (ACPS). The role of such a mechanism is to incentivise investment in new peaking capacity but also serves to remunerate base load and mid-merit capacity for a proportion of fixed costs not recovered through a SRMC energy only market controlled by the Bidding Code of Practice (BCoP).

It is important to remain cognisant of one of the objectives of a capacity market in a market such as the SEM, it is to ensure adequacy of capacity and to reward generator availability. From the midterm review consultation, it was clear that the SEM Committee are fully aware of these conditions stating, "*it is mindful that the*

[9] SEM-15-032, page 3

CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance"[10].

A key role of the CPM is to compensate generators, of all types, for investments that are not fully recoverable through a SRMC energy only market. To best achieve this and to ensure existing investors are not penalised for their investments to date, it is important that the CPM delivers a clear signal to investors in relation to future payments. In addition to this, a lack of regulatory certainty brought on by unjustified changes or inaccuracies in the application of the mechanism, its parameters, or data inputs will similarly penalise investors, jeopardising current and future investment in the SEM and ISEM.

During previous responses to the CPM we raised concerns about the lack of stability in the mechanism. This seemed to be addressed by the 2013 decision and subsequent indexing for 2014 and 2015. Given this recent stability, and given the uncertainty surrounding I-SEM, it is unclear why the RAs are introducing such uncertainty to the CPM at a time when the market is already facing significant change. The RAs must avoid the perception that they manipulate the BNE calculation parameters to obtain the lowest outcome.

The Capacity Payment Mechanism (CPM) is well understood by banks and investors and is relied upon as a fundamental aspect of the market when evaluating projects. The current turbulent investment climate is a combination of the legacy of the Eurozone crisis and the regulatory instability being introduced by the transition to the ISEM. This results in a depleted pool of banks active in the SEM, North and South, with many of these continuing to be risk adverse. A sudden and drastic 19% decrease in the pot further compounds this problem. As a result it becomes increasingly difficult to support any investment in the sector. Based on the proposed 2016 payment we do not believe any party could justify a peaking investment. Of major concern is that this significant reduction has been reached using demonstrably unrealistic assumptions in the ACPS calculations which increases perceptions of regulatory risk in the SEM and ultimately leads to higher costs for investors and therefore consumers.

We urge the RAs to review their analysis and decisions in relation to the ACPS. The current perception of regulatory risk in the SEM is a result of a number of changes to the ACPS calculation enacted by the RAs. Persisting with the current analysis will exacerbate the current situation by discouraging investment, increasing the risk weighting associated with generation investment and undermine confidence in the sector as a whole. Re-opening the process for a ground up calculation gives the RAs the opportunity to correct previous errors which have led to a consistent underestimation of the ACPS, as previously highlighted by Energia, other industry participants and the EAI.

[10] SEMC CPM Medium Term Review SEM-12-016 ,

2. Financial Parameters

2.1 Weighted Average Cost of Capital (WACC)

The proposed WACC for a BNE peaking plant located in NI of 4.46% (ROI: 4.52%) represents a c32% (ROI: c50%) reduction from the WACC applied in the 2013 BNE decision. The reduced WACC is the fundamental driver behind the proposed BNE peaker cost reduction of 19% to €65.5/KWh. Such a significant reduction merits and requires comprehensive review of all elements of the WACC determination including a re-evaluation of the validity of the building block assumptions for today's market. In particular, we would highlight the following key areas:

a) The generation markets across Europe have seen a dramatic downturn since the parameters, and in particular the WACC, were last set in August 2012 for the BNE peaker. As per Ernst & Young's "Benchmarking European power and utility asset impairments[11]" report, there was €32 billion of generation asset impairments across Europe in 2013 compared to a €10 billion on average 2010 - 2012. The coal/gas switch only started to take effect in 2012, spark spreads had not diminished to the levels seen today, and only recently have we experienced a dramatic reduction in oil and in turn gas prices. All these factors have substantially increased the market risks associated with investment in generation. In particular they no longer support the assumption that the cost of capital to be applied to a BNE peaker should be that of a vertically integrated utility presuming that such an investor would be prepared to apply a hurdle rate for investment in generation equivalent to its corporate WACC based on its entire business portfolio.

b) The realities of the increased risk profile associated with investment in generation in today's market have been disregarded by CEPA.

c) Further, setting the WACC on the basis that the investor in a BNE peaker will be an investment grade vertically integrated utility that has the ability to raise debt at a corporate level is discriminatory against a number of both current and new entrant participants in the Irish energy markets. In the SEM HLD Proposal paper (AIP/SEM/53/05), one of the specific criteria listed for the selection of an explicit CPM was that "The CPM should not unfairly discriminate between participants"

d) By way of (c), the proposed WACC is uneconomic for potential investment from entities with a lower credit rating (and therefore higher WACC) which otherwise would have been considered to be likely investors in BNE peaking plant; This proposal also has the potential impact of threatening investments

[11] Benchmarking European power and utility asset impairments 2012, http://www.ey.com/Publication/vwLUAssets/Benchmarking_European_power_utility_asset_impairments/$File/Benchmarking_European_PU_21_June%202013_DX0192.pdf

already made in the SEM, giving rise to further and potentially significant adverse consequences arising from this paper.

e) The proposed WACC levels are significantly below recently published regulatory benchmarks;

f) In certain areas, such as the approach to gearing, it is clear that CEPA have been influenced by the SEM Committee, notwithstanding the underlying data. CEPA should be permitted to make conclusions on an entirely independent basis; and

g) There are several inaccuracies and inconsistencies in the methodology and calculations used by CEPA.

The analysis outlined below also draws on the findings of Frontier Economics who were commissioned by the Electricity Association of Ireland (EAI) to review the appropriate WACC for a BNE peaker in 2016 and a copy of their report entitled "Benchmarking the BNE WACC for 2016" is appended to this response. Some of the key issues pertaining to the SEM Committee's proposed WACC are outlined in the remainder of this section under thematic headings.[12]

2.2 Cost of debt analysis and proposal

The cost of debt analysis and proposal presented by CEPA:

1) Is manifestly biased towards network regulated assets despite CEPA acknowledging that "regulated networks are not direct comparisons, as these will be typically lower risk than the BNE". Of the 18 benchmark bonds shown for the NI cost of debt analysis, 16 of the bonds are for pure regulated network assets in respect of electricity, gas or water and therefore do not have any vertically integrated utility features despite the key assumption underpinning the proposed WACC is that the BNE peaker is financed by a vertically integrated utility. A key feature of price controls being set for regulated network assets is that the WACC determined by the Regulators is set relevant to the risk profile of the network businesses and specifically disregards the risk profile of the wider organisation. Therefore any business comprising or including network assets materially distorts the benchmark analysis undertaken by CEPA.

2) For the RoI, the only benchmark bonds shown are for ESB for which c65% of ESB's business (including NIE, 59% excluding NIE) is underpinned by regulated network assets, is state owned, which taken together, materially distort the cost of debt of that business. Other vertically integrated utilities across the UK and Europe have not been considered such as SSE, Iberdrola, EON, RWE and EDF. Though despite their higher cost of capital illustrated in Appendix 4, the merits of such large scale organisations is further questioned below.[13]

[12] It should be noted that the issues discussed herein are not exhaustive and the issues and evidence outlined in Frontier Economics report should also be considered together with detailed evidence considered later in our assessment.

[13] More detailed analysis in respect of the bond benchmarks provided by CEPA is presented in Appendix 4 together with our views on the appropriate benchmarks to be applied.

3) Is predicated on the assumption that a BNE investor has an investment grade credit rating with market data for BBB rating employed. This assumption is not appropriate, it is anticompetitive in that it can inhibit new entrants from entering the market, impeding the further development of competition, and discriminates against a number of investors in the Irish energy market which:

    - either will not be of sufficient scale to achieve investment grade, for example; Moody's ratings agency methodology for unregulated utilities applies minimum threshold of total assets of greater than €9 billion for investment grade assessment of the relevant grid category ; or
    - Do not have sufficient mix of operations to achieve investment grade, for example; Moody's rating agency methodology for unregulated utilities effectively requires businesses to have operations across various markets to enable investment grade assessment of the relevant grid category

    As there is significant indigenously owned Irish generation currently in the market, it is clearly anticompetitive, in that it can inhibit new entrants from entering the market, impeding the further development of competition, and is discriminatory to generically assume the next BNE investor will have an investment grade rating and if so will apply the benefit of that rating and in turn cost of capital to any investment in the Irish generation market.

    The detailed analysis outlined in the appendix shows that the investment grade credit ratings of the utilities outlined by CEPA arise due to the regulated network asset backing of the utilities quoted together with the scale and breadth of operations of those utilities.

    The fundamental fact that a market participant would make a BNE investment decision on a standalone basis and entirely on the merits of the individual investment case at that point in time has been ignored. Hurdle rates for generation investments particularly considering the dramatic downturn in the generation market seen since 2012, will be considerably higher than the consolidated WACC of a vertically integrated utility. An investor, even if it were a vertically integrated utility, will not apply a blended WACC to individual investment decisions. Cross subsidising asset investments would ultimately impact the company's overall credit profile and rating which would reflect the investment in a riskier asset class leading to higher cost of debt and in turn a higher cost of capital. Cross subsidising is not the manner in which vertically integrated utilities operate and individual hurdle rates would be applied to each investment depending on the risk profile of the investment.

    The assumed BNE investor as a minimum should allow for a non-investment grade rating of BB and in reality single B rating is appropriate if the analysis is to be wholly non-discriminatory. As is highlighted by Frontier Economics, the benchmark yields for a non-investment grade are significantly higher than those presented in the CEPA report.

RBS have carried out an illustrative ratings assessment of how a BNE investment would be treated (see Appendix 3). Their assessment also indicates that a BNE peaker would not have investment grade characteristics and therefore even if a vertically integrated utility were to invest in such an asset, the WACC to be applied to such a peaker should bear the ratings characteristics of such an asset. Therefore a non-investment grade rating of B to BB is more appropriate and the cost of debt should be applied accordingly.

RBS observe in their analysis that:

> *"Without the scale, geographical diversification and substantial EBITDA contribution from regulated networks, a generation & supply utility operating solely in the Island of Ireland market is unlikely to be rated "investment grade" with the gearing levels / capital structure proposed by CEPA / the Regulatory Authorities*
>
> - *Utilities referred to in the CEPA/Ramboll "Cost of a best new entrant peaking plant for the calendar year 2016" paper (p.53) and rated "investment grade" in EMEA benefit from scale, diversification and regulated network cash flow advantages which largely drive their investment grade rating. None of these characteristics would benefit the credit profile of the assumed benchmark greenfield plant*
> - *All of the referenced integrated utilities maintain gearing significantly below 60%; their ratings are based on the actual leverage rather than an "optimised" capital structure as referred to in the paper.*
>
> *As such, the capital structure and rating assumptions put forward in the CEPA paper would appropriately remunerate a hypothetical integrated utility group rather than the assumed benchmark greenfield plant's risk profile at the asset level*
>
> - *When making an investment decision, an integrated utility investor would themselves likely consider the risk profile of the stand-alone project – rather than the group's risk profile – to determine an appropriate return / remuneration on their capital."*

4) Has been incorrectly calculated applying RPI as the inflation factor as opposed to CPI for the calculation of the real risk free rate for the NI WACC which is a clear methodological error by CEPA that has a material effect in determining the real cost of debt.[14]
5) Departs from the more clearly defined approach applied previously in that an "all in cost of debt" has been determined as opposed to the setting of the risk free rate and debt premium separately. Whilst CEPA's analysis references the "all in cost of debt" assumed taking account of factors such as country risk premium, debt issuance costs etc, it is difficult to ascertain the bottom up basis for the "all in

[14] See Frontier Economics Report, page 17.

cost of debt" determined and departs from the more clearly defined approach taken in 2013 and in recent regulatory benchmarks discussed further below.

6) Uses current debt yield information that is now out of date. Debt yields are cyclical and are influenced by many ongoing economic and political factors. As highlighted in the Frontier report, underlying debt yields have recently increased to a level significantly above the yields used by CEPA in determining WACC.

Frontier Economics have provided an evidenced based, bottom up approach to the appropriate cost of debt to be applied which more clearly aligns with recent regulatory analysis and takes into consideration the issues outlined above.

2.3 Gearing

Gearing at 60% is inappropriate and CEPA appear to have been guided to disregard the evidence outlined in their own assessment by the SEM Committee. Instead of CEPA using their own analysis, they have applied the gearing level of 60% on the basis of "for regulatory stability purposes and based on guidance from the SEM Committee''.

Even if you were to ignore the clear evidence provided by CEPA that gearing would be in the range of 20-40% for vertically integrated businesses, simply reversing the calculations of the financials proposed by CEPA for the BNE peaker shows that 60% gearing corresponds to an debt/ EBITDA multiple of c8x which is at a level too high to effectively be able to raise financing and clearly cuts right across the assumption that financing is representative of an investment grade standing.

RBS have performed simplified financially assessment of the proposal put forward by CEPA (see Appendix 3) for a BNE peaker and their assessment indicates that applying:

- Gearing of below 35% is the indicative level to meet BBB investment grade status from a financial metric perspective notwithstanding this is then applied against a business risk assessment;
- S&P's methodology debt/ EBITDA multiple of 2-3x (effectively equating to 20-30% leverage) is the indicative level to meet BBB investment grade status from a financial metric perspective notwithstanding this is likewise applied against a business risk assessment.

The evidence from all parties, including CEPA, strongly indicates that a gearing level of 60% is not realistic. An instruction from the SEM Committee to use a 60% gearing figure in face of the evidence provided is manifestly wrong.[15]

2.4 Cost of equity analysis and proposal

Based on the cost of equity and proposal presented by CEPA:

1) the approach taken on the equity beta has changed from the previous approach even though the gearing assumption of 60% has not changed. Previously the

---

[15] See Appendix 5 – Gearing analysis

equity beta ranged from 1.2 to 1.3 whereas even though the gearing is unchanged CEPA have proposed a range of 1.10 to 1.35.

2) as outlined in Frontier Economics report, a Total Market Return of 7.1% for NI and 6.8% for ROI is more appropriate based on recent regulatory evidence whereas CEPA's analysis proposes ranges of 5.5% to 6.5% for NI and 5.5% to 7.0% in ROI which are not deemed appropriate.

As outlined below for the SONI price control proposed by NIAUR in April 2015, 6.5% was proposed as the Total Market Return which whilst at the high end of the range proposed by CEPA is nonetheless inconsistent with the BNE proposal.

2.4.1 Recent benchmarks

The WACC proposed is completely at odds with the WACC proposed for SONI Limited in April 2015 of 5.42% pre-tax real (CEPA 4.46%) by NIAUR for a 100% NI regulated business for which the business, market and financial risks fall considerably short of the risks that a BNE peaker would be exposed to. The SONI proposal also continues to distinctly apply a debt premium to the risk free rate as opposed to the calculation of an "all in debt cost" with a total cost of debt of 3.2% applied with NIAUR concluding that it "considers a cost of debt of 3.2% to be broadly representative". This is 0.95% to 2.45% higher than CEPA's analysis which is completely illogical. As outlined above, the Total Market Revenue (TMR) applied by NIAUR in SONI's price control was also 6.5% which whilst at the high end of the range proposed by CEPA is nonetheless inconsistent with the BNE proposal.

The WACC proposed inconceivably disregards the recent findings in February 2015 of the Competition & Markets Authority (CMA) whereby their report entitled "Energy market investigation, Analysis of cost of capital of energy firms" sets out the CMA's assessment of the WACC appropriate to vertically integrated and standalone generation businesses where the WACCs pre-tax real range from 4.87% to 6.73%, midpoint 5.8%. The evidence supporting the CMA's assessment is primarily information gathered from the 'Big 6' utilities in GB which as detailed below benefit from large scale operations primarily underpinned by network assets and therefore a premium would be expected over and above the position set forth by the CMA for an investor in Ireland if it is to be non-discriminatory. The CMA assessment also distinctly applies a debt premium to the risk free rate as opposed to the calculation of an "all in debt cost".

2.4.2 Other observations

- Whist CEPA's report makes reference to the recent acquisitions by Centrica and SSE of plant previously owned by BGE and Endesa as the basis for the assumption of an integrated utility being the appropriate investor, it should be noted that in relation to these acquisitions:
  - The Whitegate plant acquired by Centrica as part of the BGE acquisition was valued at £30m/ £67k/MW and falls considerably short of the cost of a new BNE peaker of £470k/MW. The Whitegate plant was commissioned in November 2010 and within 3 years of its life, BGE took a €232m impairment

on the asset. This illustrates the reality of the value of generation assets and the inherent market risks associated with such generation assets in the current SEM market and this will only be further exacerbated with the new ISEM market. It clearly demonstrates that an investor in generation assets will apply a considerably higher cost of capital to a BNE peaker investment to compensate for such risks and to invest at a cost 7 times the value of a CCGT such as Whitegate.

  - Endesa also took an impairment of €200m to sell its Irish assets to SSE in order to exit the Irish generation market. Like Centrica, SSE acquired Irish assets at low cost.

- Whilst CEPA acknowledge the Energia Group as a vertically integrated utility in the Irish market, nowhere in its report does it reflect the reality of such an investor which does not have the benefit of regulated network assets or the scale of operations like the Big 6 UK utilities. The Viridian Group has a non-investment grade rating of B (despite having c25% of its business from regulated activities) and in February 2015 issued a bond at 3.8x leverage at a coupon of 7.5% and as outlined by Frontier Economics more typifies the cost of debt for utilities which do not have either network assets or the benefit of scale like the Big 6 UK utilities.

- The use of Centrica and SSE to justify the assumption that an integrated entity is the appropriate investor and therefore apply a low WACC does not match the reality we have seen in Ireland. Both Centrica and SSE have acquired assets from vendors who have had to sell. They have been purchased at a price which reflects the risk profile such integrated utilities apply to the Irish market.

2.5 Energia Group proposal in conjunction with Frontier Economics

As a result of the shortcomings of the WACC proposal outlined in summary above, the Energia Group recommend that the appropriate WACC to be applied for the 2016 BNE determination should be as ascertained by Frontier Economics, summarised as follows:

	Republic of Ireland		**Northern Ireland**	
	Low	**High**	**Low**	**High**
Gearing	30.0%	30.0%	30.0%	30.0%
Cost of equity (post-tax, real)	**5.91%**	**5.91%**	**6.07%**	**6.07%**
Risk free rate	2.00%	2.00%	2.00%	2.00%
Equity risk premium	4.80%	4.80%	5.00%	5.00%
Asset beta	0.6	0.6	0.6	0.6
Equity beta	0.81	0.81	0.81	0.81
Cost of debt	**1.98%**	**4.44%**	**2.60%**	**4.96%**
WACC (vanilla , real)	4.73%	5.47%	5.03%	5.74%
WACC (pre-tax, real)	**5.32%**	**6.06%**	**6.09%**	**6.80%**
Midpoint (pre-tax, real)	**5.69%**		**6.45%**	

The above results in a WACC of 6.45% for a BNE peaker in Northern Ireland and 5.69% for ROI. More importantly the WACC is better aligned with:

- the WACC recently determined by NIAUR in April 2015 for SONI which was proposed at 5.42% real pre-tax for a 100% regulated business with a much lower business risk profile where a 1% differential would intuitively be expected;
- The WACC recently determined by CMA for a either a vertically integrated business or generation only business in the range of 4.87% – 6.73%. Whilst the WACC proposed above is at the top end of the range for the CMA proposal this reflects the reality that:
    - there will be a premium attached for investment in the Irish SEM where the only mechanism for recovering fixed costs is through the capacity payment mechanism. The benchmarks applied in the CMA review is primarily based on the data from the Big 6 utilities with operations across the UK and Europe (and with the exception of Centrica all have network asset backing);
    - investors will be cognisant of the new market rules due to come into effect from 2017 and the inherent risk that naturally applies.

2.6 Additional costs

2.6.1 Technology options

The plant selected here is a 200MW Altsom GT13E2. Given the slow growth of demand in the sector, building such an incremental size would automatically result in overcapacity and reduced revenues, even in the “theoretical” world. Hence the tendency would be to go for a smaller sized unit with a higher WACC to compensate for the lost revenue caused by it entering the market. The entry of a 200MW plant into the market would immediately render it unviable

Since the commencement of the SEM a distillate fired unit has not been built or even proposed. This could be seen as a strong indication that the choice of plant is not reflected in real life commercial decisions.

2.6.2 Investment costs

It cannot be assumed that a plant setting up would be able to purchase land at the referenced rate. The cost of the land is influenced by the nature of the business setting up. As the figure here does not take this into account it is likely that the cost of land here is being underestimated. The recent upturn in the economy is also likely to have a bearing on the cost of land. In addition, the current strength of the £ vs € should inflate the NI cost by 16% (1.3863 vs 1.1958).

2.6.3 Utility connection costs

The CEPA analysis of electrical connection costs for NI shows costs to be €10.5m, this is higher due to the 2015 site being in a rural location. Table A2.1 indicates that there has been an increase in cost of €2.66m. However, the actual cost used in 2013 was €12.1m which is €2.1m more than the figure used for this calculation. Similar to the general investment cost the significant gains Sterling has made in the last year has not been reflected in the calculation.

The estimates used for gas and water connection costs are based on the 2010 BNE calculation. Given that 6 years has passed the assumption would be that these costs have gone up. Similarly there is no rational reason why the water connection costs in NI will be the same as ROI.

2.6.4 Recurring costs

Costs such as O&M, insurance and rates seem to only have increased in line with general market changes and have ignored the exchange rate. It would be expected that units based in NI would have increased more in euro terms due to the substantial increase in the value of Sterling. Any estimation of these costs should reflect the exchange rate and market increases.

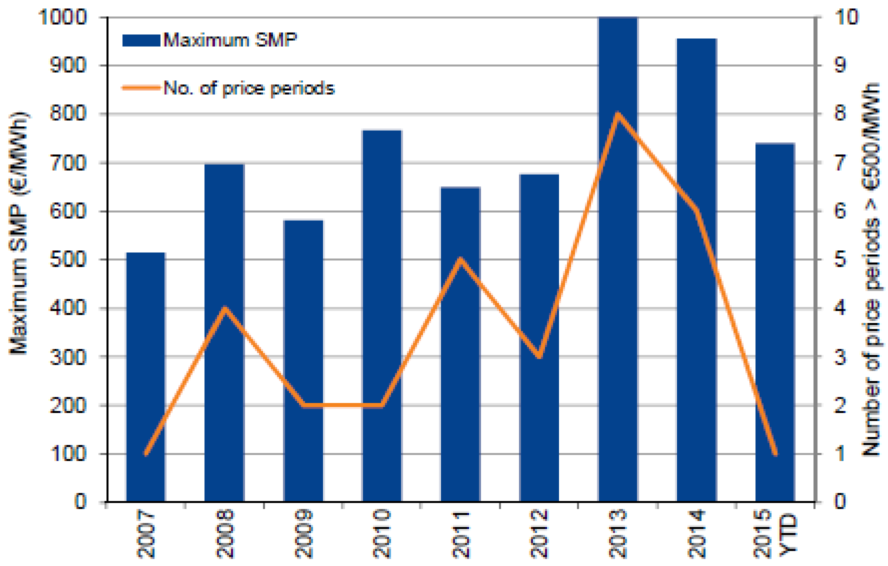
Gas fired generators in NI are also unable to include gas capacity costs in their market bids as there is no short term product available. This is an additional layer of cost that has not being factored in.

3. Infra-Marginal Rent, Ancillary Services & Capacity Requirement

3.1 IMR

The IMR calculation is predicated on the idea that a BNE plant would expect to earn the IMR to contribute to the recovery of its fixed costs when the market is at equilibrium. This assumption that a peaker plant will earn IMR is ill-founded and not supported by the realities of the market over any timeframe. As was the case previously, the IMR calculation should be based on a genuine expectation of the IMR that could be earned by the BNE as opposed to using an IMR derived from a set of circumstances (8 hour LOLE) that have not, and will not occur in reality. Since 2007 the SEM price cap has only been reached on one occasion, this was a single occurrence in 2013 (Fig.1).

Figure 1 – Historical maximum SMP and frequency of high price periods (>€500/MWh) observed in SEM (€/MWh, nominal)



Source: SEMO, restricted to assessment of EP2 runs over relevant period

*2015 YTD: Prices until 12th June

As Poyry note in their report, originally the IMR calculation was a forecast of expected revenue. The IMR deduction in 2007 was €14.19/kW, but fell to zero in the years 2008 to 2012 reflecting the greater availability of plant relative to demand.

This change in IMR acted to offset the spreading of payments from the ACPS across a greater number of plant. The two terms (IMR and the spreading of payment) were a counter-balance in periods of under- and over-supply, bringing payments back towards a more stable, equilibrium level – as is a stated objective of the RAs.

However, change was introduced in the CPM Medium Term Review to ensure that the IMR remained stable at the level expected in equilibrium (assuming the LOLE assumption is correct which it is not), without applying similar methodology to the spreading of the ACPS across plants. This change has led to an inconsistency as in years of greater plant availability, payments to each plant will be further from the equilibrium as the IMR term no longer moves in counter-balance to the spreading term. This is inconsistent with the stated intention of the CPM.

To re-align the practise with the intent and either the IMR should (as it was previously) be based on a forecast or the ACPS should be based on the total installed capacity rather than the required capacity to satisfy an 8 hour LOLE.

3.2 Ancillary Services

The CEPA paper uses the assumption of 2% running hours for the BNE. However the paper notes that a BNE unit is expected to meet the last MW of demand and therefore is unlikely to run for 2% of the year. This means that the AS revenues are over-estimated.

Additionally the unit is said to have an availability of 95%. If it then runs for 2% of the time, it implies that the period of the year where it is available but not running is 93%. The calculation determines the revenue for de-synchronised replacement reserve using 95% instead of 93% and therefore over-estimates AS revenues.

In addition to this, the proposal to only re-open the ancillary service deduction following any implementation of DS3 introduces a clear bias in the calculation. If the AS deduction is to be re-opened due to DS3, any consequent cost increases for generators should also be included. A simpler approach is to maintain all such elements at the current levels.

3.3 Capacity Requirement

The capacity requirement has been materially and systematically understated now and in previous consultations on the CPM. This shortcoming has a significant impact on the size of the overall capacity pot. The current predicted capacity requirement is 7,070MW. This is a marginal increase on last year but is significantly short of the >8GW that is required according to the GAR. A simple reverse engineering of the figures in the GCS demonstrates a total TER peak of 6,671MW (table A-1) and total NI & RoI dispatchable plant of 9,911MW (tables A-4 and A-5) giving a probabilistically calculated surplus of 2,025MW (table A-16). Even if this suplus was deducted from the dispatchable plant alone (and no credit given to wind or other renewables), it would result in a requirement of 8.7GW.

Again, using data from the GCS, it can be seen that the 7,070MW capacity requirement in the consultation only provides a mere 6% margin on TER peak and 8.2% on transmission peak. A margin of this magnitude has not been accepted anywhere on the island before, where margins have typically been in the 30-40% range. The validity of a 7,070MW capacity or 6% capacity margin is further undermined when this is compared to NI.

The TER peak in NI is 1,738MW. Plants that are available for dispatch equate to 2,167 MW, when the additional capacity contracted from AES is included (250MW), this rises to 2,417 MW. The resulting margin is 25% and 39% respectively. DETI and NIAUR instructed SONI to contract for the additional 250MW when the margin was indicated as being acceptable on an all island basis. The margin proposed in the consultation paper represents one large generation unit which would not be acceptable to RAs, politicians or TSOs.

Analysis of the last three years of the CPM reveal that a far higher security standard has been maintained with the consequence that the capacity payment sum has overestimated the IMR earned by the BNE investor over this period. Any ‘ground up calculation’ must address the inconsistencies in the methodology to ensure confidence in the regulatory regime.

The 8 hour LOLE used in the calculation does not reflect reality as is clearly demonstrated by the recent decision to award a contract to AES but also by previous decision such as that around WPDRS and the APC. In reality, interventions are made to target average security standard greater than the 8 hour LOLE GSS

Should the SEMC choose not to review the LOLE being used in the calculation of ACPS, it will further call into question the analysis and basis on which the Ballylumford contract was awarded to AES.

4. Regulatory Stability & Regulatory Risk

The consultation represents one of the most significant changes to the CPM, since the inception of the SEM. The average ACPS from 2007-2015 was €551,257,000 with an average BNE peaker cost of €80/kW/yr. The proposed 2016 BNE peaker cost is €65.50/KW/yr with the ACPS dropping to €463,103,448. This equates to an 18% drop from the average BNE cost and a 16% drop in ACPS. Such a significant reduction in revenue sends signals to potential investors that revenue streams are incredibly volatile.

The CPM high level design (AIP/SEM/53/05) lists the goals of an effective Capacity mechanism as meeting the following criteria:

- The CPM should be ' transparent and predictable'
- The CPM must encourage both the construction and maintained availability of Capacity in the SEM along with resulting in a more stable and less volatile payment to generators.
- The CPM should not unfairly discriminate between participants.

The core principles of the CPM are designed to deliver a fair and consistent payment to generators and for the system to operate in a clear and transparent manor ensuring that there is sufficient capacity. The current proposal moves away from these principles and presents generators with volatility, instability and an increased debt risk. The process also unfairly discriminates between participants by favouring large utilities with network backing.

Regulatory Risk is an additional layer of risk on top of traditional market factors. In regulated markets such as the SEM it is largely to do with perceptions of regulation and changes to regulated revenue streams, and is a major factor in the availability and cost of finance to a company. Interventions which may be seen as amending specific assumptions to deliver a desired result for consumers but result in volatile revenue streams for generators add significantly to perceptions of regulatory risk with the following consequences:

- Reduced access to capital
- An increase in the cost of capital
- Adversely impacts entities credit ratings

The above was reflected in the Competition Commission's investigation of Phoenix Natural Gas Limited's price control assessment[16]. The UK Competition Commission

[16] CC Phoenix Natural Gas Limited price determination, https://assets.digital.cabinet-office.gov.uk/media/551948b8e5274a142b000186/phoenix_natural_gas_limited_price_determination.pdf

noted that increased regulatory risk was likely to lead to a higher cost of capital, while also affecting the regulated companies' ability to access capital markets (as a result of the adverse impact on the companies' credit ratings). In particular, in its decision, the CC acknowledged the importance of upholding regulatory expectations. As well as the outcomes identified by the Competition Commission, one must also be cognisant of the likely adverse impacts such outcomes are likely to have on customers.

5. Revenue Adequacy

The Electricity Regulation Act 1999, Section 9 states that the CER has a statutory duty to have regard to the need to ensure that licence holders (such as generators) are capable of financing their undertakings. This does not appear to have been done.

If there is a real risk that the changes proposed to the CPM will impact on the ability of licence holders to finance their activities, this must weigh heavily with the CER in its decision-making and must be balanced against other objectives to which the CER is statutorily obliged to have regard.

A summary of generator profitability from the SEMC Generator Financial Performance Assessment for Financial Year 2013 is shown below[17].

Financial Year 2013	Total	Wind	Hydro	Gas	Coal	Peat	Distillate & Oil	Pump St.
Volume of Electricity Sold - MWh	27,317,623	3,858,483	576,483	12,679,734	7,959,179	2,336,645	31,366	(124,268)
Revenue	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**
SEM Pool	€ 1,788,288	€ 221,258	€ 36,836	€ 818,318	€ 538,518	€ 153,000	€ 7,950	12,408
CfD	€ 110,467	€ 17,654	€ 916	€ 84,566	€ 4,505	€ 3,024	€ -	(197)
Capacity	€ 436,840	€ 7,206	€ 6,298	€ 246,179	€ 63,655	€ 19,187	€ 79,007	15,307
Other Revenue	€ 480,919	€ 74,620	€ 1,299	€ 331,612	€ (23,984)	€ 70,637	€ 10,853	15,882
Total Revenue	**€ 2,816,515**	**€ 320,738**	**€ 45,348**	**€ 1,480,675**	**€ 582,695**	**€ 245,849**	**€ 97,810**	**43,400**
Operating Costs	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**	**€,000**
Fuel Related Operating Costs	€ 1,375,369	€ 115	€ -	€ 951,182	€ 290,536	€ 124,852	€ 8,684	-
Non-fuel Operating Costs	€ 576,572	€ 99,444	€ 20,965	€ 248,990	€ 120,767	€ 36,645	€ 32,284	17,475
Total Operating Costs	**€ 1,951,941**	**€ 99,559**	**€ 20,965**	**€ 1,200,172**	**€ 411,303**	**€ 161,497**	**€ 40,968**	**17,475**

	Total	Wind	Hydro	Gas	Coal	Peat	Distillate & Oil	Pump St.
EBITDI	**€ 864,574**	**€ 221,179**	**€ 24,383**	**€ 280,502**	**€ 171,391**	**€ 84,352**	**€ 56,842**	**€ 25,924**
Depreciation & Impairment	€ 371,239	€ 113,932	€ 1,659	€ 160,132	€ 53,613	€ 33,893	€ 8,011	€ 3,697
EBIT	**€ 493,335**	**€ 107,247**	**€ 22,724**	**€ 120,371**	**€ 117,779**	**€ 50,459**	**€ 48,831**	**€ 22,228**
Interest & Tax	€ 147,185	€ 85,939	€ -	€ 52,062	€ 3,473	€ 1,080	€ 4,630	-€ 68
Net Profit	**€ 346,150**	**€ 21,308**	**€ 22,724**	**€ 68,309**	**€ 114,305**	**€ 49,379**	**€ 44,201**	**€ 22,296**
Operating Margin - %	31%	69%	54%	19%	29%	34%	58%	60%
Net Margin - %	12%	7%	50%	5%	20%	20%	45%	51%

It is apparent that the level of capacity payment in the market in 2013 was crucial to ensuring a reasonable level of generator profitability, comprising 16% overall revenue (and 17% of revenue for gas plant). Since 2013, IMR has reduced further, particularly for gas plant, meaning that the proposed reduction in the ACPS for 2016 will cause a genuine risk that gas plant may not be capable of financing their undertakings.

6. Conclusions

As evidenced in this response, reports produced by Poyry and Frontier and the information provided by RBS, the substantial reduction in the ACPS is unjustifiable.

[17] SEM-14-111 SEM Generator Financial Performance; December 2014 – Table 2, p13 (adjusted to remove Whitegate impairment)

Even if this were not the case, the timing of this substantial reduction is questionable. With two years left of the current market arrangements a more consistent approach would be to continue with the existing arrangements of indexing the 2013 decision. The uncertainty created is occurring at a time when other policy shifts and inconsistencies are having major impacts on investment in both thermal and renewable generation in the SEM. The sudden and unwarranted drop in the ACPS damages the sector and will have further implications for investment in both renewable and thermal generation across the UK and Ireland. The increased perceptions of regulatory risk in the SEM will ultimately lead to higher costs for investors and therefore consumers.

The only rational solution available to the RAs is a genuine re-opening of the ACPS for ground–up calculation of the BNE, the capacity requirement and WACC, as we have evidenced in this report. If this is not possible in the time available, the 2016 ACPS should be set equal to the 2015 ACPS whilst a full and accurate re-calculation is made for 2017.

APPENDICES

Appendix 1

Frontier Economics Report

"Benchmarking the BNE WACC for 2016"

Appendix 2

Poyry Consulting Report

"Review of Consultation on Proposed Annual Capacity Payment Sum for 2016"

Appendix 3

RBS analysis enclosed

"Preliminary Ratings consideration for a new BNE peaking plant"

Appendix 4

Bond benchmarks

Bias toward network regulated assets

The cost of debt analysis performed by CEPA is manifestly biased towards network regulated assets despite CEPA acknowledging that “regulated networks are not direct comparisons, as these will be typically lower than the BNE” (pg 49 CEPA report). Of the 18 benchmark bonds shown for the NI cost of debt analysis (pages 58-59 CEPA report) and as depicted below, 16 of the bonds are for pure regulated network assets in respect of electricity, gas or water and therefore do not have any vertically integrated utility features despite the key assumption underpinning the proposed WACC is that the BNE peaker is financed by a vertically integrated utility. It is appropriate and illogical to include these bonds in the analysis. A key feature of price controls being set for regulated network assets is that the WACC determined by the Regulators is set relevant to the risk profile of the network businesses and specifically disregards the risk profile of the wider organisation. Therefore any business with networks assets materially distorts the benchmark analysis undertaken by CEPA.

Company	Maturity	Amount	Credit Rating	All in yield	Spread to Gilt (bps)	Gas Networks Transmission	Gas Networks Distribution	Electricity Networks Transmission	Electricity Networks Distribution	Water Network	Generation & Supply	Other	% Network assets	Suitable comparator
NIE Finance	Jun-26	£400m	BBB+	3.01%	103	x	x	✓	✓	x	x	x	100%	x
Wales and West Utilities	Dec-23	£250m	A-	2.67%	120	x	✓	x	x	x	x	x	100%	x
Wales and West Utilities	Mar-30	£750m	A-	3.22%	107	x	✓	x	x	x	x	x	100%	x
Western Power Distribution	Oct-24	£400m	BBB	2.82%	112	x	x	x	✓	x	x	x	100%	x
Western Power Distribution	Apr-32	£800m	BBB	3.40%	115	x	x	x	✓	x	x	x	100%	x
Scotia Gas Networks	Feb-25	£350m	BBB	2.68%	91	x	✓	x	x	x	x	x	100%	x
National Grid	Jun-27	£525m	A-	2.78%	80	✓	✓	✓	x	x	x	✓	90%+	x
Centrica	Mar-29	£750m	**A-**	3.33%	134	x	x	x	x	x	✓	✓	0%	✓
Centrica	Sep-44	£550m	**A-**	3.86%	138	x	x	x	x	x	✓	✓	0%	✓
Northern Power Grid	Jul-32	£150m	A-	3.34%	109	x	x	x	✓	x	x	x	100%	x
Northern Gas Networks	Mar-40	£200m	BBB+	3.64%	122	x	✓	x	x	x	x	x	100%	x
Kelda Water	Feb-20	£200m	BB-	4.62%	331	x	x	x	x	✓	x	x	100%	x
Wessex Water	Sep-21	£300m	BBB+	2.31%	90	x	x	x	x	✓	x	x	100%	x
United Utilities	Mar-22	£375m	BBB+	2.44%	121	x	x	x	x	✓	x	x	100%	x
Thames Water	Jun-25	£500m	A-	2.79%	102	x	x	x	x	✓	x	x	100%	x
Anglian Water	Feb-26	£200m	BBB	3.38%	160	x	x	x	x	✓	x	x	100%	x
Anglian Water	Oct-27	£250m	A-	3.03%	105	x	x	x	x	✓	x	x	100%	x
Affinity Water	Mar-36	£250m	A-	3.43%	104	x	x	x	x	✓	x	x	100%	x

The only suitable comparator in respect of its business being a vertically integrated utility is with respect to Centrica however it has a credit rating of A- which is notably better than the CEPA basis of BBB.

For the RoI, the only benchmark bonds shown (page 76) is for ESB for which c65% of ESB’s business (including NIE, 59% excluding NIE) is underpinned by regulated network assets and is state owned, which taken together, materially distorts the cost of debt of that business.

Company	Maturity	Amount	Credit Rating	All in yield	Spread to Gilt (bps)	Gas Networks Transmission	Gas Networks Distribution	Electricity Networks Transmission	Electricity Networks Distribution	Water Network	Generation & Supply	Other	% Network assets
ESB	Sep-17	€600m	BBB+	0.36%	53	x	x	✓	✓	x	✓	x	65% (59% exc NIE)
ESB	Nov-19	€500m	BBB+	0.52%	69								
ESB	Jan-24	€300m	BBB+	1.14%	95								
Average per CEPA					72								
Pricing average at 17 June 2015					92								

The bonds quoted for ESB by CEPA are also primarily short dated bonds and thus materially distort the average spreads quoted even though ESB does have a bond in issue with maturity 2027 as outlined further below. It should be further noted that the pricing of such short dated bonds has increased by 20bps to 92bps since CEPA's analysis was performed.

Other vertically integrated utilities across the UK and Europe have also been ignored such as SSE, Iberdrola, EON, RWE and EDF even though the merits of such large scale organisations is to a large extent flawed as outlined further below in respect of the appropriateness of their investment grade standing.

Outlined below is the recent pricing of bonds for the Big 6 utilities with operations across the UK and Europe together with ESB in the RoI. As can be seen the Spread to gilts for GBP bonds are on average 160 bps some 35bps higher than CEPA's analysis for UK bonds above. For the Euro bonds the average spreads are 134 bps some 62bps higher than those quoted for ESB above.

Company	Maturity	Amount	Credit Rating	All in yield	Spread to Gilt (bps)	Gas Networks Transmission	Gas Networks Distribution	Electricity Networks Transmission	Electricity Networks Distribution	Water Network	Generation & Supply	Other	% Network assets
Centrica	Mar-29	£750m	Baa1/A-	3.86%	152	x	x	x	x	x	✓	✓	0%
Centrica	Sep-44	£550m	Baa1/A-	4.36%	158	x	x	x	x	x	✓	✓	0%
EDF	Jul-31	€500m	A+	4.00%	151	x	x	✓	✓	x	✓	✓	Not disclosed will be sizeable
SSE	Nov-28	£500m	A-	3.66%	135	x	✓	✓	✓	x	✓	✓	50%
EON	Jun-32	£975m	BBB+	4.23%	169	x	✓	x	✓	x	✓	✓	30%
RWE	Jun-30	£760m	BBB+	4.56%	212	x	✓	x	✓	x	✓	✓	45%
Iberdrola	Sep-27	£350m	Baa1/BBB	3.68%	145	x	x	✓	✓	x	✓	✓	50%
Average				4.05%	160								

Pricing 17 June 2015 Euro bonds

Company	Maturity	Amount	Credit Rating	All in yield	Spread to Gilt (bps)	Gas Networks Transmission	Gas Networks Distribution	Electricity Networks Transmission	Electricity Networks Distribution	Water Network	Generation & Supply	Other	% Network assets
EDF	Oct-24	€500m	A+	1.76%	102	x	x	✓	✓	x	✓	✓	Not disclosed will be sizeable
ESB	Jun-27	€500m	Baa1/A-	2.31%	137	x	x	✓	✓	x	✓	x	65% (59% exc NIE)
Iberdrola	Jan-23	€600m	Baa1/BBB	1.82%	131	x	x	✓	✓	x	✓	✓	50%
RWE	Feb-43	€150m	BBB+	3.09%	165	x	✓	x	✓	x	✓	✓	45%
Average				2.25%	134								

For Centrica it should be noted that their spreads have increased by c20bps since CEPA's analysis.

The above also highlights how with the exception of Centrica, all the utilities benefit from a large proportion of their business operations (c50%) being regulated network assets and as outlined below this very much underpins their investment grade standing and in turn their low cost of debt. The intrinsic benefit of such underpinnings has not been excluded in CEPA's analysis.

The following benchmark bonds more accurately reflect the cost of debt that is appropriate to generation investment in today's market. Such bonds do not have the benefit of investment grade standing as they reflect the position that the assets being financed do not have the benefit of scale, network assets support or state ownership and therefore are indicative of the cost of debt/hurdle rate that even a vertically integrated utility should apply in its investment decision for a BNE peaker.

Pricing 17 June 2015 non-investment grade generation asset bonds

Company	Maturity	Amount	Credit Rating	All in yield	Spread (bps)
MEIF Renewable Energy	Feb-20	£190m	BB	6.03%	470
Infinis	Feb-19	£350m	BB-	5.54%	434
AES	Oct-19	$200m	BB-/BB	4.85%	337
AES	Mar-24	$750m	BB-	5.79%	356
Intergen	Jun-23	$750m	B+	7.76%	559
Intergen	Jun-21	£175m	B+	8.08%	649
Viridian	Mar-20	€600m	B	7.69%	773
Average				6.53%	511

The above clearly demonstrates the increased cost of debt associated with generation assets which due to the inherent business risk profile of such assets will not benefit from investment grade status and ratings are in the non investment grade range of B to BB. Spreads are on average 511bps, some 350bps wider than the investment grade vertically utility entities above; even for BB rated assets, the average spreads are 400bps some 250bps higher.

As outlined previously, hurdle rates applied by organisations are with respect to the underlying risks of the assets themselves and organisations do not cross subsidise investments. The above demonstrates the additional cost of debt that should be applied to a BNE peaker in the determination of its WACC.

Appendix 5

Gearing assessment

The following is a simple back cast of the financials proposed for the BNE peaker and what that implies in terms of leverage multiples. Applying 60% gearing implies EBITDA/debt leverage of 7.8x which is clearly inconsistent with investment grade ratios and financing at such levels would not be achievable.

BNE consultation 2016 inputs		
Plant capacity	MW	195.7
BNE capacity payment	€/Kw	65.5
Inframarginal rent	€/Kw	6.10
Ancillary service income	€/Kw	4.64
Operating costs	€m	5.187
Capital cost	€m	126.94
Gearing assumed	%	60

Annual EBITDA	
	€m
Capacity revenue	12.8
Inframarginal rent	1.2
Ancillary service income	0.9
	14.9
Operating costs	(5.2)
EBITDA implied	**9.7**

Implied leverage		
	€m	
Capital cost	126.9	
Gearing	**60%**	
Implied level of debt	76.2	
Implied debt/EBITDA	**7.8x**	
Typical leverage for investment grade	2.0x	3.0x
Typical gearing expected	**15%**	**23%**

It should be noted the above is based on a BNE peaker:-

- being able to earn inframarginal rent at the levels outlined by CEPA for which historic evidence outlined previously has proven not to be the case; and

- the demand assumption applied in the calculation of the BNE capacity pot aligning with actual demand. Again we have outlined the issues we have in relation to the calculation of demand.

Both of which will fundamentally result in a BNE peaker not being able to achieve EBTIDA earnings of £9.7m and therefore negates the financing ability of such an asset.