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REVIEW OF CONSULTATION ON PROPOSED ANNUAL CAPACITY PAYMENT SUM FOR 2016

A note from Pöyry Management Consulting to Electricity Association of Ireland FOR INCLUSION IN EAI CONSULTATION RESPONSE

June 2015

1. BACKGROUND AND SUMMARY

Pöyry Management Consulting (UK) Ltd ("Pöyry") has been commissioned by the Electricity Association of Ireland ("EAI") to provide a view on the propositions within the Single Electricity Market Committee ("SEM-C") consultation on the Proposed Annual Capacity Payment Sum For 2016[1] ("the consultation").

The Capacity Payment Mechanism (CPM) currently implemented in the Single Electricity Market (SEM) is a price based mechanism determined by the fixed cost of a Best New Entrant (BNE) peaking plant. Under this mechanism, the total annual payment sum (known as the Annual Capacity Payment Sum or ACPS) is a product of the capacity requirement for a given year and the fixed costs of a BNE peaking plant. Payments are therefore designed to be targeted at a level that allows full recovery of the fixed costs of the BNE plant in line with the original intention of the CPM as:

"a fixed revenue CPM that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments[1]".

The review conducted by Pöyry has assessed both the overall methodology for setting the ACPS as well as the individual terms within the equations. The ACPS formula contains numerous terms and due to its forward looking nature many assumptions are required, many of which are well justified by the SEM-C. However, in this note we summarise our key area of concern in the calculation – that is:

The formulation of the Infra-Marginal Rent (IMR) discount is potentially inconsistent in a number of areas, each of which would lead to systematic under-payment to generators against the stated intention of the CPM:

1. **the current approach of fixing the IMR term each year appears inconsistent with the stated intention when viewed in conjunction with the spreading of money in the ACPS across all generators during periods of over-supply;**
2. **the IMR value calculated is out-of-line with recent SEM experience although the consultation claims to represent a "ground-up review"; and**

[1] SEM-15-032: Fixed cost of Best New Entrant Peaking Plant, Capacity requirement and Annual Capacity Payment Sum for the Trading Year 2016; Consultation Paper; May 2015.

3. **the LOLE used in the IMR calculation itself appears to be an unrealistic expectation of an equilibrium market position based on recent System Operator actions.**

This remainder of this assessment note presents our analysis of the IMR term and outlines in more detail our reasons for concern.

2. INFRA-MARGINAL RENT EARNED BY BNE PLANT

The Capacity Payment Mechanism (CPM) currently implemented in the SEM is a price based mechanism determined by the fixed cost of a Best New Entrant (BNE) peaking plant. Under this mechanism, the total annual payment sum is a product of the capacity requirement for a given year and the fixed costs of a BNE peaking plant. Payments are therefore designed to be targeted at a level that allows full recovery of the fixed costs of the BNE plant. The fixed costs of the BNE plant are determined in the consultation as the annualised investment costs less the infra-marginal rent (IMR) earned and ancillary service payments.

The formula used to determine the IMR deduction in the BNE calculation is outlined below:

$$IMR = \left(\frac{PCAP - BID}{1000}\right) * Outage\ Time * (1 - FOP)$$

where:

IMR = Infra-Marginal Rent (€/kW)
PCAP = SEM Price Cap (€1000/MWh)
BID = Bid price of BNE plant
FOP = Forced Outage Probability
Outage time = Loss of load under security standard

The loss of load under security standard referred to is the all island Generation Security Standard (GSS) of 8 hours Loss of Load Expectation (LOLE). The LOLE is defined as the number of hours in a year that the available generation is unable to meet the expected demand, i.e. when there could be load-shedding[2]. It is also noted that it is an unconstrained LOLE such that the load loss does not take into account any limitations from the transmission system or reserve requirements.

LOLE is calculated on a probabilistic basis, recognising that load loss each year would vary depending on the out-turn demand and supply situation. Even in an equilibrium position with a LOLE of 8 hours, the actual Outage Time would vary in each year.

SEM-C has used a forced outage probability of 5.91% and a bid price of 189.7 based on the average bid of distillate peakers on 31 March 2015. These assumptions lead to a final IMR reduction of €6.10/kW as shown below:

$$IMR = [(1000 - 189.7) \div 1000] * 8 * (1 - 5.91\%) = €6.10/kW$$ [3]

IMR calculation is therefore predicated on the idea that a BNE plant would expect to earn the IMR in the market over its lifetime in order to receive the necessary revenue to incentivise new entry. The remainder of this section is structured into three key questions as follows:

- In Section 2.1 we examine the formulation of the IMR term within the context of the whole ACPS formula to test the 'top-down' consistency of the approach;

2 EirGrid/SONI: All-Island Generation Capacity Statement; 2015-2024

3 SEM-15-032: Fixed cost of Best New Entrant Peaking Plant, Capacity requirement and Annual Capacity Payment Sum for the Trading Year 2016; Consultation Paper; May 2015.

- We then test whether or not the IMR approach is reflective of the recent historical market experience in Section 2.2; and
- Finally, Section 2.3 discusses whether the theoretical concept of the IMR is in-line with other elements of SEM market design and operation from a 'bottom-up' perspective as currently implemented.

2.1 Is the IMR term consistent with wider ACPS formula and approach?

Reviewing the theory of the CPM as reported in the 2011 Medium Term Review we note that the CPM is designed to reflect the equilibrium situation:

"a key point in the selected design of the CPM within the broader theory of remunerating generators in the SEM is to consider the circumstance in which the market is at equilibrium"[4]

Under such a situation we may expect plants to be rewarded as if they are in equilibrium ignoring the influence of the under- or over-supply.

Original IMR methodology

Under the original methodology for the calculation of IMR, a forecast of 'realistic' revenue was used for IMR, such that the IMR discount was variable in each year. This IMR discount would fall in over-supply periods (working to bring overall payments up) and rise in under-supply periods (bringing payments down). As an example the IMR term in 2007 was €14.19/kW, but fell to zero in the years 2008 to 2012.

In the original methodology in place from 2007 until 2012, the variation in the IMR term would tend to be counteracted by the spreading of payments from the ACPS across all plant in the system. In an over-supply situation this spreading would bring payments to each plant back down, but bring them back up in an under-supply situation. The two terms were working to, at least partially, counter-balance each other in periods of under- and over-supply, bringing payments back towards a more stable, equilibrium level.

Current IMR methodology

The current formulation of the IMR-term, introduced in the 2011 CPM mid-term review, is specifically designed to ensure that the IMR term itself stays stable at the level expected in equilibrium. That is, the IMR term reflects expected average payment flows assuming an equilibrium LOLE. However the interaction with the spreading of the ACPS across all plants now leads to a potential inconsistency– specifically that in periods of under- or over-supply, payments to each plant will actually be further from the equilibrium as the IMR term no longer moves in counter-balance to the spreading term. In the currently over-supplied market this means that the money received by plant is reduced by the spreading of the ACPS across all plant, but there is no counter-acting movement in the IMR term. The further dilution of the CPM price when there is over-capacity is therefore inconsistent with the stated intent.

To understand the materiality of the difference in approaches we note that, using the previous methodology for the IMR calculation it appears likely that the IMR term would have continued at zero, increasing payments to generators by €6.10/kW. Alternatively, if

[4] SEM-11-088 CPM Medium Term Review

the current IMR formulation is preferred but stable payments are required, the ACPS could be based on the total installed capacity rather than the required capacity to satisfy an 8 hour LOLE. Both of these alternative approaches would lead to a materially higher ACPS for 2016 which would, we consider, be more consistent with the stated intention of the CRM.

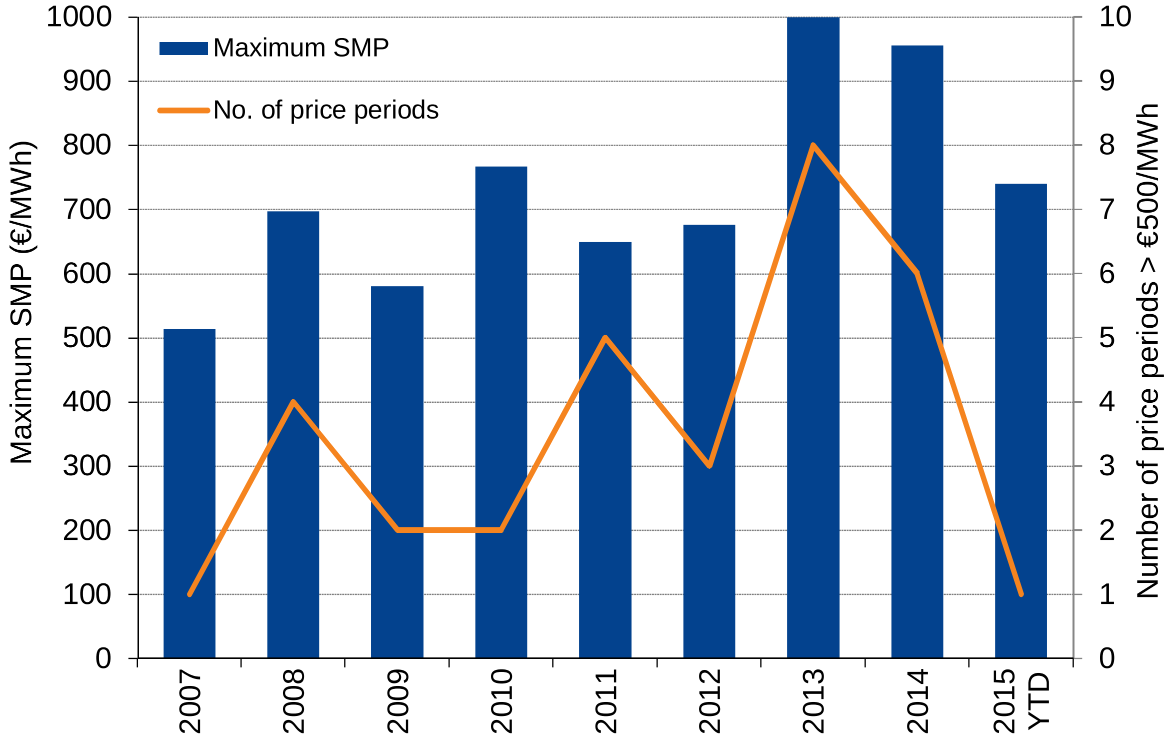
2.2 Is the IMR assumption reflective of historical market experience?

The consultation document states that *"the value for 2016 has been re-opened for ground-up calculation"*. Such a ground-up review would ordinarily be expected to take at least some account of historic market experience, with particular reference given to actual outturn in the three years since the previous consultation.

To date in the SEM, there is little historical evidence to support the economic theory that PCAP is reflective of expected market outcome under load loss.

Figure 1 below, shows the historical maximum price observed in the SEM between 2007 and 12 June 2015 and the frequency of market prices above €500/MWh (i.e. half PCAP). The SEM price cap has only been reached on one occasion since 2007 which was a single occurrence in 2013.

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



*2015 YTD: Prices until 12th June

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

It would be expected that if we were to see an average out-turn year of 8 hours of load loss, years with less than 8 hours load loss (or none at all) would be offset by years with more than 8 hours load loss. However, during that same period there have been no periods of lost load according to the market schedule algorithm. This is part evidenced by the historical minimum capacity margin per year never being less than zero since 2011 as shown in Table 1 below.

Table 1 – Historical minimum capacity margin and peak demand observed in SEM (MW)

Year	Minimum Margin (MW)	Peak Demand (MW)	Minimum Margin as % of Peak Demand
2011	1,988.3	6365.6	31.2%
2012	2,318.7	6124.1	37.9%
2013	2,521.8	6133.2	41.1%
2014	2,476.1	6201.3	39.9%
2015 YTD	3,407.4	6219.6	54.8%

* 2015 YTD covers period until 12th June
Source: SEMO, restricted to assessment of EP2 runs over relevant period. Historical data available from 2011 only

If the IMR were to be regarded as reflective of the market situation, it follows that we should see evidence of numerous periods where the price moves to PCAP, during periods of load loss. A simple review of the history of the SEM pricing indicates that assuming an average unconstrained LOLE of 8 hours leading to 8 hours per year of PCAP is not reflective of the recent historical operation of the market.

2.3 Would the IMR be reflective of the market outcome in a long-run equilibrium?

Notwithstanding the above, we note that from Section 2.1 that the stated aim of the IMR deduction is to reflect a long-run equilibrium and this may differ from recent SEM market outcomes. This does not necessarily mean that practical market experience to date should be disregarded; indeed, the use of an equilibrium market outcome as an assumption of average revenues suggests that we would expect the market to tend towards that point on average. However, it does lead us to examine whether or not we could theoretically expect revenues to correspond with the IMR under such equilibrium conditions.

As noted above, the SEM-C has used the all-island GSS of 8 hours unconstrained LOLE in the BNE methodology, as the expected level of load loss in equilibrium. The generation adequacy software used to evaluate the GSS calculates the probability that in any half hour there will be insufficient capacity to meet demand by assessing forecasted system demand in a given half hour versus the forecast availability of all plants.

The methodology therefore implies that, under equilibrium conditions the market should experience 16 half hour periods of unconstrained load loss (which in turn will lead to 16 half hours of prices equal to PCAP).

We address three main areas of concern for the relationship of current market design and LOLE in equilibrium in turn in Sections 2.3.1 to 2.3.3 below. We then present our overall conclusions in 2.3.4.

2.3.1 Interaction of the all-island GSS with the NI security standard

The security of supply standard of 8 hours referred to in the LOLE is reflective of the GSS on an all-island basis. This 8 hour LOLE is also the standard used in Ireland specific calculations but Northern Ireland (NI) has a tighter security standard of 4.9 hours LOLE.

Due to the interconnection between the two markets, and noting the unconstrained market schedule used to determine whether or not the market experiences load loss in a given period, it is not realistic that the all-island unconstrained GSS could drop below 4.9 hours at equilibrium. This is particularly the case where it is feasible for a System Operator to influence the security standard by structuring payments outside of the capacity payment mechanism. An all-island unconstrained GSS below 4.9 hours at equilibrium could be realistic if there are specific protocols in system operation which effectively mean that - in extremis - customers in Ireland would be disconnected before customers in Northern Ireland. We are unaware of any such protocols.

As a key example of this, the 2014 Generation Adequacy Statement highlights concerns around security of supply in NI, as the second North-South interconnector will not be complete until late 2017 at the earliest. SONI estimated that the capacity margin in NI would reduce to ~200MW from 2016 (where 0MW = a LOLE of 4.9 hours) and therefore began a competitive tender process to ensure greater security of supply. In response, in November 2014 SONI awarded a three-year capacity contract to the AES Corporation to help meet anticipated shortfall in coming years[5]. Provision of this local reserve capacity will involve upgrading two of AES' existing Ballylumford B Station units.

It would appear that SONI has both the desire and tools to acts to raise the security standard, above that required to meet an 8 hour all-island LOLE and no attempt has been made to isolate the effects of this intervention on the energy or capacity market. It is therefore unclear how, under the current market structure and generation adequacy approach, an overall GSS standard of 8 hours LOLE may arise in the future.

2.3.2 Generation adequacy approach implies stated unconstrained load loss level for Ireland and NI is not actual target of the System Operators

The decision noted above makes specific reference for the need to have a tighter security standard due to network constraints both in the North-South interconnector and in the Moyle interconnector. The situation is reflective of a wider issue – additional load loss over and above that expected in an unconstrained schedule can be expected when accounting for constraints in the system. In other words, in order to have an unconstrained LOLE of 8 hours it may be necessary to have either:

1. a largely unconstrained market such that the constrained position is very similar to the unconstrained, with large costs to alleviate all potential constraints; or
2. a constrained LOLE expectation of materially more than 8 hours.

From the Generation Adequacy Report (GAR) 2014[6] Appendix 4 we can see that the basecase generation surplus for NI in 2016 was expected to be 210MW which equates to only 1 hour of lost load, well within the 4.9 hours stated standard. However, the argument is then made that High Impact Low Probability events could cause greater outage in a

5 Security of Electricity Supply in Northern Ireland: An updated information paper from the Utility Regulator and the Department of Enterprise, Trade and Investment; December 2014

6 We reference both the GAR 2014 and the GAR 2015 in this review as both are required to observe the justification and data on recent market interventions.

particular year, and that more capacity can be justifiably contracted. To put it another way, even though the security standard is exceeded by more than 200MW in NI when using the pre-defined probabilistic approach, additional capacity procurement is justified to increase the security standard still further for reasons other than unconstrained load loss.

This approach is borne out in the 2015 capacity statement where Figure 4-1 clearly shows a security standard in NI significantly above the 0 line (equating to 4.9 hours lost load) but then increasing from 2016 to 2018 due to short-term 'local reserve services contract'.

Analysis of historical SO Capacity Interventions

A review of historical Generation Adequacy Reports (GAR) against capacity interventions made by the TSOs suggests that there is also some historical evidence that interventions are made to target an average security standard greater than the GSS, beyond the recent intervention made for Ballylumford. Although such evidence is not conclusive, and indeed past behaviour is not necessarily indicative of future intent, we particularly note that:

- the TSO-funded Winter Peak Demand Reduction Scheme (WPDRS), originally introduced in winter 2003/04 was extended to winter 2013/14 despite the large surplus of capacity from 2009 onwards; and
- other specific capacity interventions are introduced between 2003 and 2008 but are generally not justified against the 'median growth, median availability' modelled scenario – instead a variable set of significantly more cautious availability scenarios are utilised each year as 'alternative bases' to justify the intervention.

We therefore conclude that recent and historical evidence of the approach taken to generation adequacy implies that, on balance, the stated unconstrained load loss level for Ireland and NI is not reflective of the actual target of the System Operators. On average a significantly more cautious approach to system security appears preferred such that the average targeted LOLE across years is materially less than the GSS.

2.3.3 'Blocky' nature of power sector investment

Given the 'blocky' nature of power sector investments, periods with much greater than 8 hours LOLE would be needed to balance out the greater levels of security provided by the entry into the market of large generating sets in order to achieve an average of 8 hours LOLE.

Utilising the data from the 2014 Generation Adequacy statement once again, we see from Chapter 5 that 200MW of additional capacity takes the load loss expectation from 4.9 hours to 1 hour. The relationship of surplus and load loss expectation is not linear but it is clear that as:

a) 200MW is the approximate stated assumed size of the BNE peaker; and

b) all-island peak demand is only expected to increase by around 30MW per year; then

c) loss of load expectation would need to be significantly greater than 4.9 hours in some years to counter balance the necessary years of over-capacity once new entry occurs.

In line with the assessment in 2.3.2 above, we find no recent evidence which suggests that years where the LOLE is significantly greater than the target GSS would be acceptable to the System Operators even as part of a strategy to target an 8 hour LOLE over time. Rather, each individual year appears to be assessed individually, with interventions targeted at any year where a deficit is projected. As such years of deficit would most likely be required to deliver an average LOLE of 8 hours, we conclude that the average LOLE across years is likely to be materially less than the GSS.

2.3.4 Conclusion on whether current market design would lead to 16 half hours of unconstrained load loss in equilibrium

Stepping back and looking at the arguments presented above we note that, while the impact and materiality of each individual point is uncertain, there appears to be a strong pattern that the current market approach of the SOs will lead to average levels of system security higher than that stated as the equilibrium GSS LOLE. We therefore conclude that the current market design and approach does not give a fair and balanced likelihood of achieving 16 half hours of load loss and consequent periods of price cap in equilibrium.

2.4 Conclusions on IMR reduction term in the BNE formula

The IMR is based on the assumption that a BNE plant would be expected to earn revenues from sale of electricity at PCAP for 16 half hours in a year. Upon reviewing the methodology applied to determine the IMR discount, Pöyry has drawn the following conclusions that indicate that the IMR reduction may be overestimated as:

1. There is an apparent inconsistency in the aim that the CPM should consider remunerating generators as if the market is at equilibrium – although the IMR term is now kept constant at a perceived equilibrium level, capacity payments will be diluted where the ACPS is paid in an oversupplied market.
2. There is no historical evidence to support the assumption that load loss occurs and the PCAP is reached if we review the current BNE methodology against historical SEM outcomes;
3. The current market design and approach does not give a fair and balanced likelihood of achieving an average of 8 hours of unconstrained load loss in equilibrium as:
   - NI has a higher security standard of 4.9 hours LOLE restricting the ability of the all-island market to move to an 8 hour unconstrained LOLE;
   - the stated 8 hours unconstrained LOLE target does not appear consistent with recent or historical SO actions, in part at least due to their concerns over ongoing system constraints; and
   - the ‘blocky’ nature of power station investment implies that some annual periods should have LOLE materially greater than 8 hours to balance over-supply periods and there is no recent evidence that such periods would be acceptable to the SOs.

Over time this over-estimation of the IMR reduction means that generators will be systematically under-paid by the CPM compared with 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.

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.

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