Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Parameters Consultation Paper

SEM-16-073

8 November 2016

EXECUTIVE SUMMARY

The European Union (EU) is building an internal market for electricity and gas, to help deliver energy supplies that are affordable, secure and sustainable. This is underpinned by the implementation of the European Electricity Target Model (EU Target Model) arising from the EU's Third Energy Package. Specifically, the EU Target Model is a set of harmonised arrangements for the cross-border trading of wholesale energy and balancing services across Europe. In this context, the SEM Committee committed to implementing the Integrated Single Electricity Market (I-SEM) that will go-live in Q4 2017, replacing the current Single Electricity Market (SEM) arrangements.

Following extensive consultation over 2014, (including an Impact Assessment) the SEM Committee published the Decision Paper on the High Level Design (HLD) for the I-SEM in keeping with its statutory objectives. Namely, the SEM Committee HLD Decision seeks to maximise benefits for consumers in the short-term and long-term, while ensuring security of supply and meeting environmental requirements. Subsequently, the Detailed Design Phase of the I-SEM commenced and a number of workstreams were established including the Capacity Remuneration Mechanism (CRM) workstream. The detailed design of the I-SEM CRM policy has been set out in three decision papers, CRM Decision 1 (SEM-15-103), CRM Decision 2 (SEM-16-022) and CRM Decision 3 (SEM-16-039). In addition, the SEM Committee issued a supplementary consultation paper CRM Consultation 3a (SEM-16-052) in September 2016, and will publish CRM Decision 3a in December 2016.

These detailed design papers have established a number of CRM parameters which need to be defined in order for the I-SEM CRM to become operational. Some of these parameters relate to the general operation of the I-SEM CRM, whilst others relate specifically to the first transitional auction. The key parameters are:

- **Administrative Scarcity Price (ASP) parameters** to apply in addition to the value of the Full ASP specified in CRM decision 2. The additional parameters are required to define the piece-wise linear pricing function specified in CRM Decision 1 which will apply when scarcity has been triggered;
- **Supplier Charging Base**- which determines the hours in which CRM costs will be recovered. The document sets out three options. An economically efficient solution would allocate charges to those hours with highest Loss of Load Probability (LoLP) is most needed. However, the recent historical evidence on LoLP patterns is inconclusive- LoLP is generally low throughout as installed capacity currently exceeds the Capacity Requirement, and patterns have not been particularly stable. This document sets out the historical evidence, set out three options for the Charging Base and analyses how the different options will differentially affect residential customer and business customers.
- Reliability Option parameters:
    - The **DSU floor price** in the Reliability Option Strike Price, following the decision in CRM Decision 2 to set a floor to the Reliability Option Strike Price, unrelated to the cost of fuel, to reflect the non-fuel opportunity costs of DSUs;
    - **Carbon Intensity Factors** for the Reliability Strike Price. These factors will depend on the fuel indices to be recommended to the SEM Committee by the

CRM Delivery Body, but this consultation explains how they will be treated and gives indicative values based on the current Directed Contract process;

- Value of **transport adders** for the Reliability Option Strike Price. These factors will also depend on the fuel indices, but this consultation explains how they will be treated and also gives indicative values based on the current directed Contract process;
- **Stop-loss limits** for Reliability Options. The annual stop-loss limit was set in CRM Decision 2 as 1.5 x the annual option fee. This consultation discusses the more granular billing period (i.e. weekly) stop-loss limit and re-affirms the CRM Decision 2 minded-to position to set the billing period stop-loss limit at 0.5 x the annual stop-loss limit.

- Parameters for new build and performance bonds and termination fees for new and existing capacity:
  - The financial threshold which meets the definition of **Substantial Financial Commitment** for new build capacity (and hence allows a bidder to bid for a Reliability Option of up to 10 years). This parameter is now termed the **New Capacity Investment Rate Threshold** in the Capacity Market Code draft. The SEM Committee is considering setting the New Capacity Investment Rate Threshold at 50% of the BNE gross investment cost, about €310/kW;
  - **Termination fees and Performance Bonds.** We suggest that an appropriate balance between objectives might be achieved by setting termination fees for new build capacity in the range of €10/kW to €40/kW, with the fee higher for new investment which is terminated close to, or after the start of the Capacity Year. We also review whether termination fees should be applicable to any other classes of bidder, including minor upgrades to existing capacity which do not meet the New Capacity Investment Rate Threshold, Unproven DSUs or any/all existing capacity. We are also consulting on the level of Performance Bond, and start from the position that any bidder should be required to lodge a Performance bond which cover 100% of any Termination Fees they may be subject to at any given time.

- **First transitional auction parameters**. This consultation paper contains a range of indicative numbers for the auction parameters for the first transitional auction. The SEM Committee is consulting further on the detailed approach to setting the parameters, but the actual parameter values will be subject to updates to account for forecasting, inflation, etc. The key auction parameters are:
  - The **Auction Price Cap.** The SEM Committee is considering setting the auction Price Cap at 1.5 x Net CONE, at the lower end of the range set out in CRM Decision 3. However, some adjustments to Net CONE may be necessary as a result of the move to the de-rating approach, the implementation ASP and Reliability Option difference payments which cap infra-marginal rent. Indicatively, based on 2017 Net CONE, these changes would result in an increase in Net CONE from €71.45 / kW of capacity to €77.81/kW of *de-rated* capacity and an Auction Price Cap of €116.71/kW of *de-rated* capacity;

- The **Uniform Price-taker Offer Cap,** now called the Existing Capacity Price Cap within the Capacity Market Code. The SEM Committee is considering setting this value at 0.5 x Net CONE, indicatively €38.90/kW of *de-rated* capacity;
- The **demand curve parameters.** This paper sets out three options for the form of the demand curve. Key elements of the curve design include the zero-crossing point as a function of the Capacity Requirement (options between 10 and 20%), and where to include a point of inflection. The actual values of the curve will be subject to the outcome of the Capacity Requirement consultation decision (consultation SEM-16-051) and to re-forecasting;
- **Locational parameters**, if required. The SEM Committee has not yet made a decision on whether to incorporate locational constraints within the CRM (consultation SEM-16-052), and if so, precisely which constraints and how. Nevertheless, if the SEM Committee decides to incorporate such constraints, locational parameters will be required, and this document discusses the format of those parameters**.**

- **Load following for secondary trading**. In CRM Decision 2 (SEM-16-022), the SEM Committee confirmed that plant should be able to physically back secondary trades using, the margin between its de-rated capacity and load following obligation within certain parameters. This document proposes a historically based approach to determining those parameters, with these parameters to be estimated by the TSOs, for approval by the SEM Committee.

We plan to publish the CRM parameters decision paper in Quarter 1 2017 and prior to this publication we expect to host a stakeholder workshop to present our emerging thing positions. Details of this workshop will be published on the SEM Committee's website[1] in due course.

Responses to this consultation paper should be sent to Mary O'Kane (mary.okane@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on 21 December 2016. Please note that we intend to publish all responses unless marked confidential.

[1] https://www.semcommittee.com/

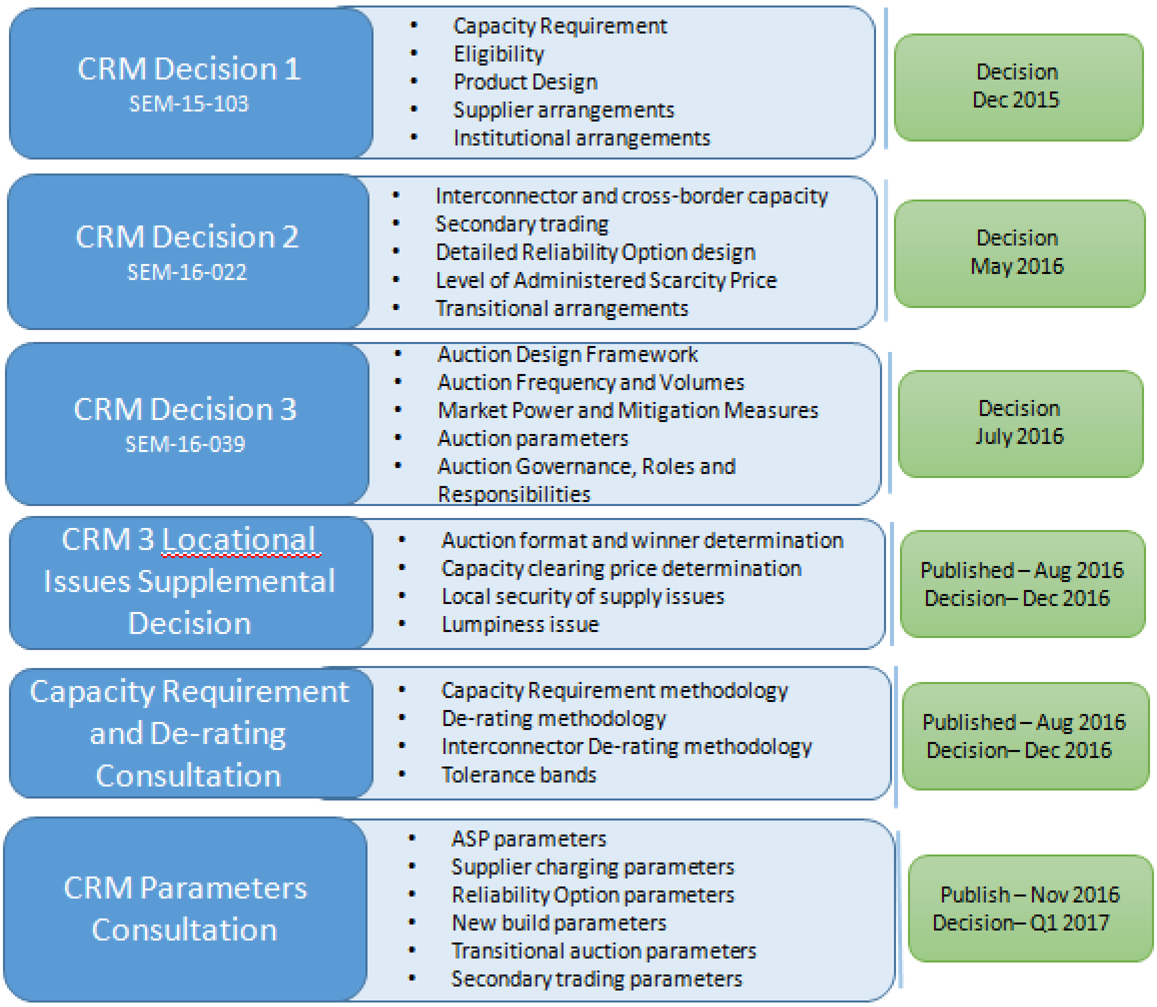
Contents

1. INTRODUCTION

1.1 OVERVIEW

1.1.1 The CRM Detailed Design is currently being finalised with the specific design features of the new capacity mechanism having been considered through a series of public consultations. These detailed design papers have established a number of CRM parameters which need to be defined in order for the I-SEM CRM to become operational. Some of these parameters relate to the general operation of the I-SEM CRM, whilst others relate specifically to the first transitional auction. An overview of this process is illustrated below.

Figure 1: Overview of CRM Policy Development



1.1.2 This consultation paper contains a range of indicative numbers for the auction parameters for the first transitional auction. This auction will take place in advance of I-SEM go live and will secure capacity for the 2017/18 capacity delivery year. While this auction is currently scheduled for June 2017, the exact timing is under review by the SEM Committee and this will be communicated to stakeholders over the coming months.

1.1.3 Parameters for subsequent auctions will be set (and as appropriate consulted upon) sufficiently in advance of each auction. To allow sufficient time between the first transitional auction and the first T-4 auction to accommodate learning and facilitate pre-qualification timelines, the first T-4 auction will not take place until 2018. More detail on the timing of the T-4 auction will be published over the coming months.

1.1.4 Auctions for each of the remaining transitional years are expected to be held on an annual basis in advance of the relevant delivery year. Once lessons learnt from the first transitional auction have been appropriately reflected, the SEM Committee will consider further the possibility of holding the transitional auctions for the subsequent transitional years in sequence before any further T-4 auctions.

1.1.5 While the SEM Committee is consulting on the detailed approach to setting the parameters in this paper, the actual parameter values will be subject to updates to account for forecasting, inflation, etc.

1.2 KEY PARAMETERS

1.2.1 This consultation considers the following key parameters:

- **Administrative Scarcity Price (ASP) parameters** to apply in addition to the value of the Full ASP specified in CRM decision 2. The additional parameters to apply will define how the piece-wise linear pricing function specified in CRM Decision 1 will apply when scarcity has been triggered, but a demand control event has not occurred.
- **Supplier Charging Base[2].**
- Reliability Option parameters:
  - **DSU floor price** in Strike Price;
  - **Carbon Intensity Factors** for Strike Price;
  - Value of **transport adders** for Strike Price;
  - **Stop-loss limit** for Reliability Options.
- Parameters for new build and performance bonds and termination fees for new and existing capacity
  - The financial threshold which meets the definition of **Substantial Financial Commitment** for new build capacity (and hence allows a bidder to bid for a Reliability Option of up to 10 years). This parameter is now termed the New Capacity Investment Rate Threshold in the Capacity Market Code draft;
  - **Performance Bond and termination fees.**
- First transitional auction parameters:
  - **Auction Price Cap;**
  - **Uniform Price-taker Offer Cap,** now called the Existing Capacity Price Cap within the Capacity Market Code;
  - **Demand curve parameters;**

[2] The Supplier Charging Base discussed in this consultation paper is separate to the issues consulted on in I-SEM ETA Basis for Supplier Charging Consultation (SEM-016-060)

  - **Locational parameters.**

- Load following for secondary trading

1.3 CRITERIA FOR ASSESSING

1.3.1 The assessment criteria for the parameter values of the CRM are based on the same principles as those applied to the I-SEM High Level Design and as agreed with the Departments in the Next Steps Decision Paper March 2013. We have developed detailed descriptions of these criteria to focus on issues that are relevant to procuring capacity and tailored to the detailed design elements of the capacity remuneration mechanism.

1.3.2 These assessment criteria are set out below:

- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.
- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Competition**: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system.
- **Practicality/Cost**: the cost of implementing and participating in the CRM should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

1.3.3 Fundamental to the SEM Committee's consideration of the overall CRM design is the European Commission State Aid Guidelines. We are actively engaged with the Departments (DCCAE and DfE) and the European Commission as we develop the capacity market design as ultimately EC approval is required for the CRM auctions to commence.

2. ADMINISTRATIVE SCARCITY PRICING PARAMETERS

2.1 INTRODUCTION

2.1.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decide that:

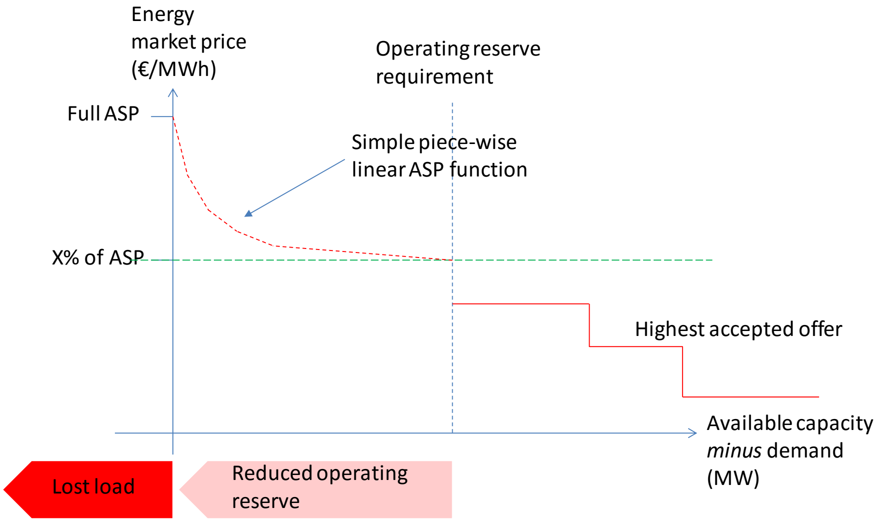
- **Administrative Scarcity Pricing will be introduced into the energy imbalance price**.
- **Scarcity (for the purposes of Administrative Scarcity Pricing) will apply when there is insufficient available capacity to cover the combination of demand and the target level of operating reserve**. Administrative Scarcity will not apply where operating reserve is reduced below target levels because the TSO uses reserve which has already been deployed (for instance to cover a forced outage), but additional capacity is available to replenish reserve.
- **A simplified piece-wise linear approximation will be applied to calculate the ASP during a period where there is insufficient capacity to maintain target operating reserve, but load is not being shed**. The BM price in any such Settlement Period will be the higher of the simplified piece-wise linear function, or the BM price as otherwise determined by the I-SEM ETA Markets Paper (SEM-15-064).

2.1.2 Subsequent related decisions made in CRM Decision 2 (SEM-16-022) are outlined below:

- Administered Scarcity will be triggered when an event corresponding to any of Customer Voltage Reduction, Planned or Emergency Manual Disconnection or Automatic Load Shedding either as defined in the SONI Grid Code or a direct equivalent event defined in the Eirgrid Grid Code is declared.
- Target Operating Reserve will be deemed to have been depleted if operating reserve (i.e. POR, SOR, TOR1 and TOR2) cannot be replaced from replacement reserve or ramping within one hour.
- The value of Full ASP will be set at the Euphemia day ahead price cap of €3,000/MWh. This will exist throughout the transition period, after which it will be based on VoLL. The exact percentage of VoLL used will be defined at a later point in time, but will be no greater than 100%. To ensure suitability, the VoLL calculation will be reviewed on a regular basis.
- The piece-wise linear function will be static, with MW of operating reserve used as the basis for its definition. The price from which the function begins will be the Reliability Option Strike Price.

2.1.3 The piece-wise linear function was illustrated in CRM Decision 2 by Figure 2, and to aid the systems specification we instructed the TSOs that the piece-wise linear function would have no more than 5 line segments.

Figure 2: Piece-wise linear ASP function



2.1.4 This CRM parameters consultation seeks to determine the values of the partial ASP, that will apply when ASP has been triggered, but full load shedding has not yet occurred, i.e. defining the values of the dotted red line in Figure 2.

2.1.5 The policies set out in CRM Decisions 1 and 2, are being implemented in Trading and Settlement Code (TSC) drafting, which will be consulted upon separately. Key points to note contained within the TSC drafting to be consulted upon are:

- The trigger for the application of the ASP is when qSTR (the quantity of Short Term Operating Reserve) is less than qROR (the quantity of Required Operating Reserve). qSTR is defined to include primary, secondary and tertiary operating reserve (POR, SOR, TOR1 and TOR2) plus RRS (synchronised replacement reserve) and RRD (De-synchronised replacement reserve[3])[4]. *The implication of these definitions for this consultation on the partial ASP is that stakeholders should be aware that the units on the x axis of the partial ASP function are MWs of qSTR*, assuming the TSC proposals are accepted following consultation;
- The quantity of Required Operating Reserve is based on the TSOs operating reserve, which is set out in the Grid Codes. The current operating reserve requirement is governed by a number of factors, but which typically requires them to have sufficient operating reserve to cover the largest in-feed. The largest potential in-feed of current capacity market units is typically Whitegate at 444MW, with the East-West Interconnector (EWIC), (which has an import capacity of 504 MW) rarely operating at full capacity. However, with the move to market coupling, including in balancing timeframes, this may change. *This means that whilst the partial ASP function will be defined from 504MW, it will not apply if qSTR, is, say 500MW and qROR is 444MW because the largest single infeed on the system is Whitegate.*

[3] which can be made available within 1 hour
[4] Units of POR, SOR, TOR1, TOR2 are not necessarily additive, as unit of capacity may be providing both POR and SOR at a given time

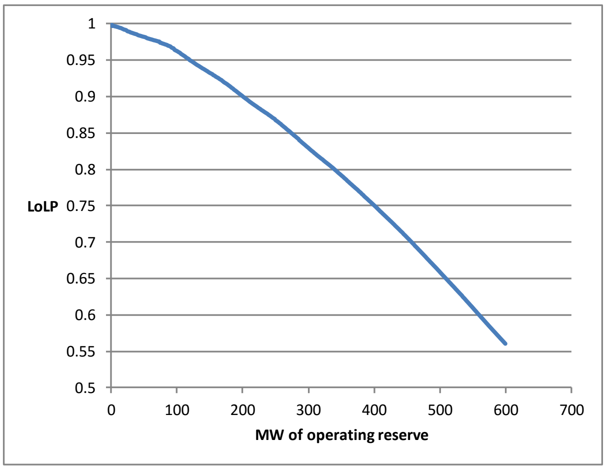
2.1.6 Stakeholders should also be aware that in practice, it is the TSOs' policy to begin involuntary load shedding at a point when short term operating reserve hits a minimum level (which is greater than zero), in accordance with the Grid Codes and its requirement to operate Prudent Utility Practice. The rationale for this policy is that if LoLP is close to 100%, it makes sense to have a controlled programme of load shedding, rather than risking system collapse. Therefore, whilst we will define the value of the partial ASP function all the way down to qSTR the likelihood is that the TSOs will undertake demand control events before qSTR reaches zero, and the value of ASP will default to FASP (currently €3,000/MWh) at that point.

2.1.7 It is also worth clarifying how scarcity will be defined within the context of the proposed TSC drafting. Reliability Options will be settled on the basis of PIMB, the price in the half hourly Imbalance Settlement Period (ISP). However, scarcity will be defined on an Imbalance Pricing Period (IPP), where the IPP is proposed to be a 5-minute period, with 6 IPPs within an ISP. Thus it is possible for the ASP function to apply in one of six IPPs within an ISP. Suppose for instance, that in the first IPP the partial ASP function is triggered, and the value of the partial ASP function is €2,000/MWh. Suppose that in the remaining five IPPs the reserve is replaced, and ASP is not triggered, with the highest accepted BM offer accepted being €400/MWh. In this scenario PIMB would reflect the time-weighted average of the price in the six IPPs and PIMB = 1/6 x 2000 + 5/6 x 400 = €666.66/MWh.

2.2 SHAPE AND SLOPE OF ASP FUNCTION

2.2.1 The TSOs have provided us with modelled estimates of LoLP as a function of operating reserve, based upon the current plant portfolio. These estimates are depicted in Figure 3. LoLP[5] is around 65%, when operating reserve is at 504MW, the size of the largest single infeed. It increases to about 75% at around 400MW and 90% at around 200MW.

Figure 3: TSO estimates of unflattened LoLP curve, as function of operating reserve

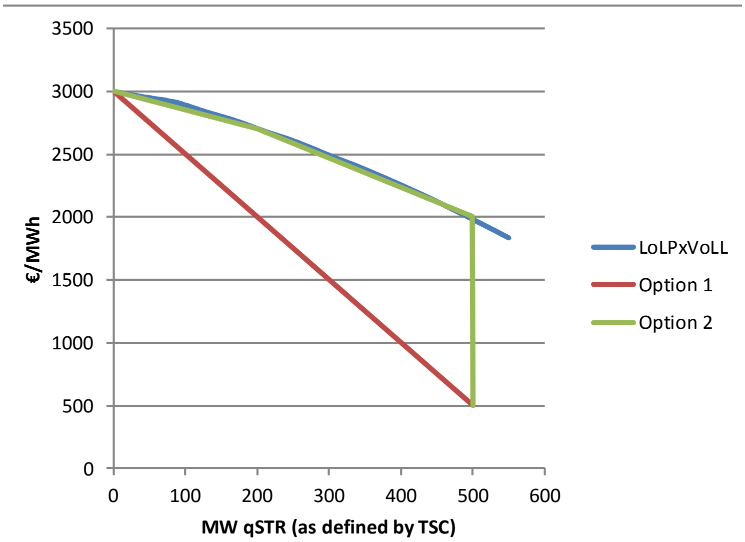


2.2.2 In this consultation paper, the SEM Committee presents two options for the partial ASP function, which are both simple piece-wise linear approximations to the LoLP curve multiplied by the Value of Lost Load (VoLL). The two options, which are depicted in Figure 4 are:

[5] We have used "unflattened" LoLP, i.e. pure LoLP figures. Figures quoted in the SEM are sometime adjusted by flattening factors.

- Option 1: Simple linear function. This option would introduce the ASP at a relatively low level, consistent with a transitional approach to implementing ASP, but as illustrated in Figure 2, does not generate prices which reflect the fact that once qSTR falls as low as 504MW there is a 65% chance that load will be lost and prices will rise to €3,000/MWh.
- Option 2: A LoLP x VoLL approximation. In this option, the ASP would be a simple two-piece linear function, which would be a reasonable approximation of the value of the product of the Loss of load Probability and the FASP, as a function of the remaining available operating reserve. This way, the ASP will be a good approximation to probability of lost load x price of lost load[6].

Figure 4: Partial ASP function options



2.2.3 Clearly a continuum of options is possible, and in presenting these two options, we do not preclude selecting an option in between Options 1 and 2.

2.2.4 Figure 4 indicates that a fairly good piece-wise linear approximation to the LoLP x VoLL curve can be gained by the simple two-piece linear function which consists of a line segment between 0 and 200MW and another line segment between 200MW and 504MW. Therefore, for the moment, we do not see significant additional benefit from using a five-piece linear function – the maximum specified in CRM Decision 2, although the functionality should be retained in systems.

2.2.5 Under Option 2, the ASP function would:

- Rise immediately at 504MW of remaining operating reserve, from €500/MWh to €2,000/MWh;
- Between 503.9MW and 0MW of qSTR the ASP function will be two-piece linear, with the two straight-line segments:

[6] The SEM Committee considered the alternative of making the function an approximation of LoLP x VoLL but capping the price at FASP. However, if this option was pursued, the ASP would hit the FASP cap, as soon the as LoLP reached around 25% (3,000 FASP / 11,000+ VoLL), and the FASP would likely apply over a range of occasions where operating reserve was reduced below target, short of full load shedding

- From €2,000/MWh when there is 503.9MW of qSTR to €2,700/MWh when there is only 200MW of qSTR; and
- From €2,700/MWh at 200MW of qSTR to the FASP of €3,000/MWh at zero qSTR.

2.2.6 Option 1 reduces the risk of volatile administered prices to market participants, by having lower ASP values than Option 2.

2.2.7 Option 2 is more cost reflective than Option 1.

2.2.8 The SEM Committee seeks feedback on whether stakeholders prefer Option 1, Option 2 or some intermediate option, and their rationale.

2.3 SUMMARY OF QUESTIONS:

2.3.1 The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why?

3. COST RECOVERY AND CHARGING

3.1 INTRODUCTION

3.1.1 CRM Decisions 1, 2 and 3 determined that:

- There will be at least two elements of the charge to Suppliers:
  - **Recovery of cost of Reliability Option Fee payments to capacity providers**. The cost of Reliability Option fee payments to generators will be recovered from charges to Suppliers. The Reliability Option fee payments in respect of Capacity Year 2017/18 will not be known until the results of the first transitional auction are published;
  - **Socialisation fund contributions.** The Supplier Charge will also need to include an element to cover any shortfall between the difference payments received from capacity providers and the difference payments due to Suppliers caused by the potential "hole-in-the-hedge". The size of the socialisation fund element of the Supplier Charge to apply in Capacity Year 2017/18 will depend upon the extent to which the initial capitalisation of the fund will be provided by the TSOs, and the extent to which additional funding will need to be provided by Suppliers;
- The charge to Suppliers will be recovered as a fixed €/MWh charge across demand in a pre-defined set of half hours that are judged to be those most likely to have high LoLP values. The specification of which half hours are used for this charging (the "Supplier Charging Base[7]") is to be consulted on in this parameter setting paper.

3.1.2 The CRM Delivery Body needs to recover the costs it reasonably incurs in setting-up and operating the I-SEM capacity market. The level of these costs will be determined as part of the TSO Price Control process. The Capacity Market Code allows for the recovery of some of these costs from Capacity Providers via a combination of Participant-based Accession Fees to the Code and unit-based Participation Fees under the Code. Either of these fees could be set to zero. The remaining costs of the CRM Delivery Body will be recovered as a charge on Suppliers under the capacity settlement arrangements of the Trading and Settlement Code. The basis of this recovery will be considered as part of the broader consultation on the Trading and Settlement Code which will start in November 2016.

3.1.3 The drafting of the TSC also has interest rate parameters, with interest to be paid on Socialisation fund balances. These parameters are considered in Section 3.3.

[7] In the latest draft of the TSC being developed by the Rules Working Group, the Supplier Charging Base is not explicitly referred to. The TSC gives effect to the Supplier Charging Base through the use of a Capacity Charge Metered Quantity Factor (FQMCCy). Effect will be given to the Supplier Charging Base by assigning the value 1 to FQMCCy in settlement periods which form part of the Supplier Charging Base, and the value 0 to hours which do not form part of the Supplier Charging Base.

3.2 SUPPLIER CHARGING BASE

3.2.1 In CRM Decision 1 (SEM-15-103) the SEM Committee decided to adopt a focused approach to defining the Supplier Charging Base, with charges to be recovered from Suppliers focused on a limited number of hours when LoLP is expected to be higher. This contrasts with the current approach, whereby capacity costs are recovered from Suppliers in the form of a capacity charge which is recovered across all hours, but with charges in each hour varying based on a series of profiling factors, which are less variable than LoLP from settlement period to settlement period.

3.2.1 The TSOs have provided us with historical estimates of LoLP from the start of the SEM until the present time. These values are summarised in Figure 16 of Appendix A. Figure 16 illustrates that the overall level, pattern of LoLP was significantly different in the early years of the SEM to now[8]. Therefore, in Figure 5, we focus on the more recent period since the start of 2013, and show a LoLP ratio, by quarter and by time-of-day. The LoLP values have been turned into a ratio by dividing the average LoLP in the relevant period by the average LoLP in the whole period since the start of 2013.

Figure 5: LoLP as ratio of average LoLP by 2013- 2016Q2, by season and time of day

	Peak (5pm to 9pm)	Mid-merit (7am to 11pm)	Night time (11pm to 7am)	All hours		Peak/ mid-merit	Peak/ Night time
2013							
Qtr1	31.1949	9.2196	0.0046	6.3396		3.4	6,714.5
Qtr2	0.0561	0.0943	0.0001	0.0649		0.6	421.8
Qtr3	1.1152	0.4266	0.0002	0.2933		2.6	5,248.9
Qtr4	2.1031	0.5513	0.0000	0.3790		3.8	71,405.1
2014							
Qtr1	5.7326	1.4456	0.0000	0.9939		4.0	152,163.8
Qtr2	0.0866	0.2477	0.0011	0.1706		0.3	79.2
Qtr3	3.9336	1.5259	0.0040	1.0499		2.6	984.4
Qtr4	0.9655	0.2588	0.0001	0.1780		3.7	14,077.8
2015							
Qtr1	0.1410	0.0363	0.0000	0.0249		3.9	10,085.9
Qtr2	0.0005	0.0012	0.0001	0.0009		0.4	3.6
Qtr3	3.6707	2.1951	0.0271	1.5160		1.7	135.7
Qtr4	13.8366	3.4988	0.0080	2.4077		4.0	1,739.8
2016							
Qtr1	0.0724	0.0231	0.0029	0.0160		3.1	25.3
Qtr2	3.8722	2.1110	0.2724	1.5228		1.8	14.2
All	4.4576	1.4464	0.0219	1.0000		3.1	203.9
All Q1s	9.2852	2.6811	0.0019	1.8436		3.5	4,912.5
All Q2s	1.0038	0.6136	0.0685	0.4398		1.6	14.7
All Q3s	2.2008	1.0520	0.0096	0.7254		2.1	228.6
All Q4s	5.6350	1.4363	0.0027	0.9882		3.9	2,099.7

[8] The average LoLP was significantly higher in 2007/8, than in subsequent years. In Q4 2007, before the recession impacted demand, and before the growth of wind capacity reduced the level of LoLP, at the Winter peak (around 17:30) LoLP was as high as 0.076, i.e. 7.6%, i.e. around 10,000 times higher than between 00:00 and 00:30 in the same quarter. However, in 2015, whilst the half hour starting 17:30 in Q4 still had the highest average LoLP of the year, even in that period the LoLP was lower than at 00:00 to 00:30 in 2007/8.

3.2.2 The values in Figure 5 are presented aggregated into peak and mid-merit hours as currently used in the SEM[9], which is broadly supported by the wider LoLP analysis presented in Appendix A. Using these periods may yield other advantages in terms of position management and liquidity of CfDs, although we would not use this approach unless also supported by LoLP data[10].

3.2.3 Certain patterns are notable in the data, and by comparison with LoLP patterns typically found in other electricity systems:

- As might be expected, LoLP is generally higher during day-time hours than at night time. Since 2013, LoLPs have on average between 3 times higher during the peak of the day (5pm to 9pm) than mid-merit hours (7am to 11pm), and 200 times higher than the average night time (11pm to 7am) LoLP[11].
- In recent years, whilst LoLP is higher on average in Winter quarters (Q1 and Q4), particularly in Winter peaks than in Summer quarters (Q2 and Q3), this effect is less pronounced than might be expected, less pronounced than in earlier years- see Appendix A. In particular, in 2015 and 2016, LoLP has been on average relatively low in Q1 peak hours, when one might expect LoLP to be highest;

3.2.4 We present three options for consultation:

- Option 1: A highly focused Supplier Charging Base focusing Supplier charges on the peak period (5pm to 9pm) in Winter quarters;
- Option 2: A focussed Supplier Charging Base, with Supplier charges focused on the period 5pm to 9pm throughout the year; and
- Option 3: A broader based Supplier Charge, with Supplier charges focused on a broader day-time period from 7am to 11pm in all quarters.

3.2.5 Option 1 focuses charges on what might conventionally be thought of as peak periods, and hence be thought to be consistent with a key capacity cost driver, peak demand. However, it may be that as penetration of intermittent generation grows, peak demand will be less of a driver of scarcity.

3.2.6 However, Option 1 may create some cash flow issues for Suppliers, particularly in the first year, if the new I-SEM CRM starts in winter and Supplier charges are front-loaded in the Capacity Year, with Suppliers having to pay the charges in the first six months and recover the costs through flatter charges to customers over the 12 months.

3.2.7 Under Options 1 and 2, residential customers, who consume proportionately more of their electricity during peak hours, will bear a proportionately bigger share of the capacity charge than their share of consumption. As illustrated in Table 1, residential customers consume approximately 14% of their energy in Option 1 hours, which is 1.28 times as much as consumers as a whole (also including business consumers), who consume only 10% of their

[9] But without the business day/non-business day distinction
[10] Since the Reliability Options provide Suppliers with a price hedge similar to a one-way CfD
[11] We note that the common definition of peak used in SEM CfDs does not include any Summer hours, but here we use peak to mean 5pm to 9pm on any day. Similarly, the definition of mid-merit hours used in SEM CfDs excludes non-business days, but here we include non-business days in the averaging.

energy during Option 1 hours[12]. Option 2, which includes summer hours would load a slightly smaller proportion of the charge on residential customers, but would still represent a significant change to the current allocation of capacity costs between customer classes. Option 3, which has the broadest Supplier Charging Base hours would result in the smallest share of the capacity costs being borne by residential customers- residential customers consume 76% of their energy between 7am and 11pm, which is fairly similar to the 74% consumed by customers as a whole.

3.2.8 The current SEM allocates capacity costs to all hours of the year, based upon a series of profiling factors. Whilst Suppliers are charged in all hours (unlike in any of the Options 1 to 3), the charge is variable in each hour. We have estimated that under the SEM CPM in 2015, the result of the allocations was that for each €/MWh of charged attracted by consumption of customers as a whole, the residential customer consumption attracted a charge of €1.02/MWh. Therefore, Option 3 is significantly closer to the way in which the SEM allocates charges between residential and non-residential customers.

Table 1: Impact of Supplier Base options on residential customers

Approach	Allocation basis	Share of consumption during Supplier Base		Relative incidence on residential customers
		Residential customers	All customers	
SEM approach	Allocated across all hours in differing proportions according to ex ante and ex post profiling factors	100%	100%	1.02
Option 1	5pm to 9pm in Winter quarters	14%	11%	1.28
Option 2	5pm to 9pm throughout the year	24%	20%	1.23
Option 3	7am to 11pm in all quarters	76%	74%	1.03

3.2.9 Based on the above analysis, the SEM Committee favours applying Option 3 for the foreseeable future, but plans to keep the Supplier Charging Base under review. The key reasons for favouring option 3 are:

- The LoLP analysis is not entirely conclusive, with patterns not entirely consistent across recent years (other than LoLP is low from 11pm to 7am), which favours a broader base of hours for charging;
- Given that there is no clear seasonal pattern or pattern within daytime hours, there does not seem to be adequate justification for implementing options such as 1 and 2 which would have a significant impact on the allocation of charges between customer classes.

3.2.10 Regardless of which option is chosen for the first Capacity Year, the Supplier Charging Base should be kept under review by the SEM Committee, acknowledging that the pattern of LoLP may change over time in response to the growth of intermittent generation, and as capacity provider respond to entry and exit signals provided by I-SEM CRM.

[12] Calculation based on 2015 consumption patterns. Customer classes DG1-1, DG1-2, DG2-1 and DG2-2 in Ireland used a proxy for customer in both Ireland and Northern Ireland

3.3 INTEREST RATES ON SOCIALISATION FUND BALANCES

3.3.1 The CRM Settlement Rules contained within the TSC include a provision for interest rates to be paid on balances in the Socialisation fund. The rules developed within the TSC provide for:

- A Base Interest Rate (BIR). The current draft of the TSC, states that "the Base Interest Rate (BIR) shall be LIBOR, but should reflect rate which TSOs can borrow at/receive on customers' money, and will be consulted on further"; and
- A surplus premium interest rate (SPR), to apply when the fund is in surplus. The SPR is the premium over BIR that is applied when difference payment receipts from Capacity Providers exceed payments to be made to Suppliers. Its value shall be determined by the Regulatory Authorities; and
- A Deficit Premium Rate (DPR), to apply when the fund is in deficit. DPR is the premium over BIR that is applied when difference payment receipts from Capacity Providers are insufficient to cover payments to Suppliers. Its value shall be determined by the Regulatory Authorities.

3.3.2 We note that LIBOR, is quoted for five curencies, including Sterling and Euros, and seven maturities from the overnight rate to the 12 month rate[13]. We seek feedback on which LIBOR (or other such reference rate) should be used as the BIR, and on values of the SPR and DPR.

3.4 SUMMARY OF QUESTIONS

3.4.1 The SEM Committee welcomes views on all aspects of this section, including:

A. Which of Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you chose and why?

B. Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?

[13] See https://www.theice.com/iba/libor

4. RELIABILITY OPTION PARAMETERS

4.1 INTRODUCTION

4.1.1 There are a number of Reliability Option parameters that need to be defined. These parameters, relate to the Reliability Option Strike Price and the operation of Stop-Loss Limits for difference payments.

4.1.2 In previous decision papers, the SEM Committee developed various elements of the Strike Price formula. In CRM Decision 3 (SEM-16-039), the SEM Committee decided that the Strike Price formula should be of the form:

Strike Price = Max [1/T% x Max [GRP + CIG x CP, ORP + CIO x CP], DSU]

Where:

T% is the reference thermal efficiency for the hypothetical Peak Energy Rent unit, which was set at 15% in CRM Decision 3 (SEM-16-039)

GRP is the gas reference price and ORP is the oil reference price,

DSU is the cost of a reference demand side unit, €/MWh which reflects the cost incurred by demand side in switching off, which may not be related to the cost of energy

CP is the carbon reference price in €/tonne of CO_2;

CIG is a parameter to denote the Carbon Intensity of a reference gas fired plant in tonnes of CO_2 per MWh of fuel content;

CIO is a parameter to denote the Carbon Intensity of a reference oil fired plant in tonnes of CO_2 per MWh of fuel content;

4.1.3 CRM Decision 3 (SEM-16-039) stated that the following elements of the Strike Price calculation will be set subsequently by the SEM Committee:

- The relevant fuel and carbon reference indices, which will be monthly reference price (e.g. an NBP gas/ARA oil reference price plus a transport adder)[14]. The CRM Delivery Body will make a recommendation to the SEM Committee on the precise choice of indices, in accordance with the principles set out in CRM Decision 3;
- DSU floor price. SEM-15-103 stated that to facilitate DSU participation the SEM Committee plans to set the DSU element of the formula around €500/MWh, although the precise value of the DSU element of the formula would be consulted on closer to I-SEM go-live. We are now consulting on it; and
- The value of transport adders[15]. The value of transport adders will depend upon the final choice of reference index (and the delivery point of the chosen index), but the

[14] Converted to the appropriate units

[15] E.g. to adjust from an NBP quote to delivery in Ireland / Northern Ireland

general approach to setting the value of these adders and indicative values are discussed further in this document; and

- Carbon intensity factors. The value of carbon intensity factors will also depend upon the final choice of reference index (for instance, different grades of fuel oil have different carbon intensities), but the general approach to setting the value of these factors and indicative values are discussed further in this document.

4.1.4 The SEM Committee will make and publish decisions on the precise choice of fuel indices and the consequential transport adders and carbon intensity factors in advance of the first transitional auction (not necessarily the CRM Parameters decision document, they may be published alongside the final values of key auction parameters, such as the demand curve in a separate document, such as an auction information memorandum, although the key Strike Price parameters shall apply until further notice, not just to the first transitional auction).

4.1.5 The SEM Committee set the annual stop-loss limit for the Reliability option at 1.5x the annual option fee, but deferred a decision on the limit per billing period. This more granular limit is now being consulted on.

4.2 DSU FLOOR PRICE

4.2.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decided that it may be appropriate to include a fixed floor price element in the Strike Price formula, which captures the cost of most DSUs, set at just over €500/MWh.

4.2.2 The original rationale for potentially setting a DSU floor was that the SEM Committee was concerned, for environmental reasons, does not want to discourage investment in DSUs, and aims to maximise the participation of DSUs in the I-SEM. The SEM Committee was concerned that there may be a disincentive on DSUs to participate in the I-SEM CRM if DSUs have to pay difference payments at a threshold price which is less than the costs of providing the demand side response, and that setting the threshold too low could interfere with the operation of the energy market. However, in CRM Decision 1, the SEM Committee also took another decision, which, at least for an initial period from I-SEM go-live, means that DSUs will not have to make Reliability Option difference payments at all, except when the demand reduction is not delivered[16].

4.2.3 This decision reflects the fact that for the time being, the energy value of the demand reduction accrues to the Supplier, not the DSU, and that it was not practical in the shorter term to make changes to energy settlement systems to credit the value of the energy saving to the DSU. However, CRM Decision 1 stated that "*on the medium to long term, the SEM Committee considers that there may be merit in further exploring Option 2* [making DSU make difference payments like generators] *and as such may review this decision post I-SEM Go-live*".

[16] In CRM Decision 1 the SEM Committee decided that The SEM Committee is of the view that a hybrid version of Options 1 and 3 from the Consultation Paper is the most appropriate treatment of DSUs for introduction from I-SEM Go-live. This hybrid option:

- Does not credit DSUs with the energy value of the demand reduction;
- Does not apply RO difference payments to DSUs when the contracted demand reduction is delivered;
- Applies an RO difference payment, only when the demand reduction is not delivered when the Strike Price is exceeded by the MRP.

4.2.4 Despite that fact that in the short term, DSUs will not be subject to difference payments (except in the event of failure to deliver the response), the SEM Committee still sees advantages in setting a DSU floor price to:

- Send appropriate longer term price signalling to DSU providers; and
- Provide a degree of simplification to the Reliability Option hedge if the Strike Price is constant most of the time (except when there is a fuel price spike).

4.2.5 Notwithstanding the fact that in the short term, DSUs will not generally be making difference payments, the level at which the floor price element should be set needs to balance a number of objectives, including:

- System security, and maximising the potential contribution of DSUs - which would favour a higher floor; and
- Limiting the incentive for generators to exercise market power in the energy market and providing a hedge to Supplier price risk, which would favour a lower floor.

4.2.6 The key complexity in setting a DSU price floor is how to treat shutdown costs- a problem which is analogous to how to treat start-up costs for generators. The shut-down issue and shut-down costs of existing DSUs is discussed in more detail in Appendix A. This analysis shows that:

- The incremental cost of all existing DSUs is less than €500/MWh; and
- If required to shut down and provide demand side response for one hour, 266MW of the 320MW of existing DSUs would have a total cost (including shutdown costs) of less than €500/MWh.

Indicative value

4.2.7 On the basis of the above analysis, the SEM Committee sees a DSU floor value of €500/MWh as striking an appropriate balance between objectives.

4.3 CARBON INTENSITY FACTORS

4.3.1 In CRM Decision 3 the SEM Committee decided to incorporate carbon intensity parameters, CIG and CIO into the Strike Price formula to recognise the existence of carbon pricing in European markets. CIG and CIO will be incorporated into the Strike Price formula as follows:

Strike Price = Max [1/T% x Max [GRP + CIG x CP, ORP + CIO x CP], DSU]

Where:

- CP is the carbon reference price in €/tonne of CO_2;
- CIG is a parameter to denote the Carbon Intensity of gas per unit of fuel input;
- CIO is a parameter to denote the Carbon Intensity of the reference oil type per unit of fuel input;

4.3.2 The Carbon Intensity parameters should be aligned with the carbon intensity of the reference fuel in the reference fuel index which will be proposed by the CRM Delivery Body for approval by the SEM Committee. In the case of natural gas, it is highly likely that the natural gas price index will be a GB NBP reference, and the value of CIG should reflect the carbon content of natural gas in the GB National Transmission system- the source of most gas burned in power stations in Ireland/Northern Ireland.

4.3.3 The Directed Contract process uses a Low Sulphur Fuel Oil 1.0% FOB North West Europe Swap as the reference fuel index for Fuel Oil. However, there is no requirement on the RAs to publish the values of the index as part of the Directed Contracts process, and commercial considerations could lead to a different reference index being chosen. The choice of index is being reviewed by the CRM Delivery Body and they will make a proposal for approval by the SEM Committee.

Indicative values

4.3.4 Assuming an NBP reference price is used, it is likely that the same assumption used by the Directed Contract Strike Price modelling process will be used, which assumes natural gas to have a carbon content of 0.0558195 tCO2/GJ = 0.2009502 tCO2/MWh of fuel input[17].

4.3.5 As discussed above, there may be more uncertainty about the physical fuel referenced in the oil index, and the value will depend upon the index chosen. However, by way of example the Directed Contracted process assumes the reference low sulphur fuel oil to have a carbon content of 0.0770130tCO2/GJ of fuel input[18].

4.3.6 The SEM Committee intends to make the final decision on CIG and CIO alongside the decision on the reference fuel index.

4.4 TRANSPORT ADDERS

4.4.1 CRM Decision 3 (SEM-16-039) confirmed that the CRM Delivery Body will calculate the fuel transport adders periodically, and submit them to SEM Committee for approval. The transport adders should be consistent with the delivery point for the relevant fuel index. For instance, if the delivery point for the chosen fuel index is ARA (Amsterdam-Rotterdam-Antwerp), a commonly quoted delivery point for North West Europe, the oil transport adders should reflect a difference in cost of delivery to a representative generation location in Ireland/Northern Ireland relative to ARA. Assuming that the quoted delivery point for the chosen natural gas index is NBP, the gas transport adder should include an adjustment for the cost of transporting gas from NBP to a representative generation location in Ireland / Northern Ireland. It does not make sense to define the adders until the reference indices have been chosen.

[17] 0.0558195 tCO2/GJ of fuel input means an OCGT with the reference 15% efficiency would output 0.0558195/3.6/15% = 1.339668 tCO2/MWh of electricity generated so the impact on the RO strike price would be 1.339668 x carbon price since 3.6GJ=1MWh

[18] 0.077013tCO2/GJ of fuel input means an OCGT with the reference 15% efficiency would output 0.077013/3.6/15% = tCO2/GJ of electricity generated so the impact on the RO strike price would be 1.848312 x carbon price

4.4.2 The SEM Committee will review the CRM Delivery Body's choice of data sources prior to Qualification for the first transitional auction, and publish the choice of indices and transport adders prior to the start of the Auction Qualification window.

Indicative values

4.4.3 As discussed above, the adders will depend upon the delivery point relevant to the indices chosen. However, by way of example, the transport adders used in the Directed Contract process for natural gas and low sulphur gas oil at the moment are shown in Table 2.

Table 2: Fuel adders in existing DC process (for Q4 2016)

Commodity	Ireland	Northern Ireland
Natural gas (from NBP)	0.00918 GBP / therm plus 0.026058279 EUR/therm	0.04240 GBP / therm (NI Commodity Element of Tx and UK Tx
Low Sulphur Fuel Oil (from ARA)	50 EUR/tonne	12 USD/ tonne to cover difference between FOB and CIF plus 6 USD/tonne to cover delivery

4.4.4 As illustrated in Table 1, transport adders can differ between Ireland and Northern Ireland, and we would propose to use whichever was higher to set the Strike Price.

4.5 BILLING PERIOD STOP-LOSS LIMIT

4.5.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decided that stop-loss limits would apply for difference payments. These stop loss limits limit a capacity provider's exposure to uncovered difference payments (difference payments that occur when the capacity provider is unavailable, so, absent the stop-loss limit, it would have to make difference payments without receiving commensurate revenues from the energy or ancillary service market) in the I-SEM.

4.5.2 In CRM Decision 2 (SEM-16-022) the SEM Committee further decided that:

- For the start of the CRM, an annual[19] and a per billing period stop-loss limit will be used[20], where the billing period was defined as the period between the physical delivery of electricity and the time at which I-SEM payments will occur;
- The annual stop-loss limit will be set to 1.5x the annual option fee for a capacity provider;
- It was minded to set the billing period stop-loss limit to 0.5x the annual stop loss limit, but that final value of the Billing Period Stop-Loss Limit will be determined as part of

[19] Per Capacity Year

[20] There are benefits to aligning the stop-loss limit with the billing period used for energy settlement. This will increase the possibilities for netting of payments and charges in settlement and will help to manage the credit risk from participants and improve the efficiency of the market. In consequence, the SEM Committee decided to use a stop-loss limit aligned with the settlement billing period, rather than use a monthly stop-loss limit

the parameters consultation process. At the time of CRM Decision 2, the billing period had not been decided, so the decision on the stop-loss limit was deferred.

4.5.3 This CRM parameters consultation focuses on the Billing Period Stop-Loss Limit.

4.5.4 Since SEM-16-022 work has progressed in the Rules Working Group (RWG) on the definition of billing/settlement periods to be included in the Trading & Settlement Code. Whilst the Trading & Settlement Code has not been finalised (approved by the SEM Committee), the current drafting is proposing that:

- A Billing Period is defined as a week and is used for imbalance and difference payment settlement; and
- A Capacity Period is defined as a month and is used for capacity payment/charge settlement.

4.5.5 In line with SEM-16-022, it is the Billing Period, rather than the Capacity Period, to which the shorter stop-loss limit will apply. This is logical, because Reliability Option difference payments are intended to provide Suppliers with a hedge against energy prices in excess of the Reliability Option Strike Price.

Key factors determining parameter value

4.5.6 CRM Decision 2 (SEM-16-022) stated that the SEM Committee is minded to set the billing period multiplier so that the stop-loss limit equals half of the annual stop-loss limit (i.e. 0.75x the annual option fee). However, it noted that if scarcity events affect more than two Billing Periods, there will be limited CRM incentive to perform after the second Billing Period. Assuming that the Billing Period will be confirmed as one week, it is more likely that a single event will span two Billing Periods than if the Billing Period was set to one month. However, since the Billing Period commences during a weekend, when demand is typically lower, the probability is reduced.

4.5.7 As noted in Section 2, if the volume of Reliability Options is equal to the 8-hour capacity LOLE capacity standard we might expect 8 hours of FASP, and 4 other hours of scarcity with reduced operating reserve, but without load shedding. However, further analysis would be necessary to understand the extent to which these 12 hours are likely to span more than 2 weeks.

4.5.8 We note that at the start of the I-SEM CRM, it is likely that there will be significantly more capacity available than the Capacity Requirement for a number of reasons. Firstly, there is currently significantly more operational capacity than Capacity Requirement and most of this capacity has to give 36-months' notice of its intention to close. Secondly, in the 2017/18 Capacity Year we will be setting the demand curve based on the 2020/21 Capacity Requirement. Thirdly, the deployment of a sloping demand curve could lead to the volume of Reliability Options exceeding the 2020/21 Capacity Requirement by up to 20% (see Section 6.4). All of these factors reduce the probability of any incidence of scarcity, let alone three different incidents in three different weeks.

4.5.9 As discussed in SEM-16-022, in theory, concerns about reducing incentives in subsequent weeks could be tackled by reducing the stop-loss limit progressively after each Billing Period in which it binds, e.g. if the limit binds in Billing Period B, then in Billing Period B+1 the limit could reduce to half its previous value (i.e. 0.375x the annual option fee) and if the limit again binds then for Billing Period B+2 it could halve again. Such an approach would maintain a degree of difference payment related incentive on capacity providers to perform throughout each Capacity Year- albeit at the expense of blunting incentives in the first and second week in which scarcity occurs. We note, however, that incentives to be available and earn scarcity prices in the energy market remain on de-rated volumes, no matter what the Reliability Option stop-loss regime. Another alternative to set the multiple for the limit at 0.75 of the annual stop-loss limit in the first relevant Billing Period, 0.5 in the second relevant Billing Period, and 0.25 third relevant Billing Period. Such an approach would be simpler, but would confine the difference payment incentive to a maximum of three relevant Billing Periods.

4.5.10 We note that there may be certain practical limitations on how we implement the Billing Period stop-loss limits for the start of the I-SEM. The settlement systems development is in progress, and we would need to assess the cost and deliverability implications of trying to implement the solutions, particularly given the implications for tracking the stop-loss limit in the context of secondary trading.

Minded to position

4.5.11 On balance, the SEM Committee remains minded to set the Billing Period multiple as 0.5 x the annual stop-loss limit (i.e. 0.75 times the Annual Option fee), but seeks further feedback on this minded-to position.

4.6 SUMMARY OF QUESTIONS

4.6.1 The SEM Committee welcomes views on all aspects of this section, including:

A) Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?

B) On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comments on the approach to setting the gas or oil carbon intensity factors?

C) Do you agree with the approach to setting transport adders set out in section4.4?

D) Do you that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?

5. NEW BUILD, TERMINATION FEES AND PERFORMANCE BONDS

5.1 INTRODUCTION

5.1.1 In this section we consulting on the following new build parameters to apply in the first transitional auction, and to subsequent transitional auctions and T-4 auctions until further notice:

- New Capacity Investment Rate Threshold: The €/MW financial threshold which a bidder must be investing to qualify as New Build, and hence allow a bidder to bid for a Reliability Option of up to 10 years. In previous CRM consultation and decision documents, we have referred to this parameter as the New Investment Threshold. This parameter is now termed the New Capacity Investment Rate Threshold in the Capacity Market Code (CMC) draft; and
- The Termination Fees and Performance Bonds required for any bidders meeting the criteria for New Build (of which the New Capacity Investment Rate Threshold is one criterion) and/or for new DSUs, which is therefore arguably unproven[21]-.

5.1.2 The CMC will specify the qualifying criteria for what investment counts towards meeting the New Capacity Investment Rate Threshold, but the investment should be for the primary purpose of providing capacity (including demand side response). The CMC will also specify any appropriate processes for validating the level of investment.

5.1.3 Any Capacity Provider must also meet the other relevant criteria to qualify as new investment specified in the Capacity Market Code, in addition to exceeding the New Capacity Investment Rate Threshold in order to be eligible for a Reliability Option of up to 10 years.

5.1.4 In addition, we consider whether it may be appropriate to impose Termination Fees and Performance Bonds on:

- Capacity which is incremental to existing capacity (and hence to a degree is unproven), but which does not meet the New Capacity Investment Rate Threshold or other criteria to qualify as New Build; and
- New DSUs;
- Existing capacity, if it chooses to close before the end of the Capacity Year, having won a capacity auction.

[21] termed New Build DSU in the Capacity Market Code, although this does not imply it has met the New Capacity Investment Rate Threshold and that it is eligible for a multi-year contract

5.2 NEW CAPACITY INVESTMENT RATE THRESHOLD (SUBSTANTIAL FINANCIAL COMMITMENT)

Background

5.2.1 In CRM Decision 2 (SEM-16-022), the SEM Committee decided that:

- New Build capacity will be eligible to bid to fix its Reliability Option fee for up to 10 years; and
- To qualify as New Build, a Capacity Provider must meet a Substantial Financial Commitment threshold in €/MW or £/MW. This threshold has been termed the New Capacity Investment Rate Threshold. Meeting the financial threshold will not be the only criteria, and the expenditure must be qualifying expenditure - superficial expenditure that is not essential for the delivery of capacity will not count.

5.2.2 In this CRM parameters consultation, we consider how we will set the financial threshold (i.e. the parameter) for the New Capacity Investment Rate Threshold. It will be set in €/MW, and will be converted to a £/MW at the prevailing forward exchange rate to be published prior to the start of the Qualifying Window for the relevant auction.

Key factors in setting the New Capacity Investment Rate Threshold

5.2.3 The intention of setting the financial threshold is to ensure that only plant making a substantial financial commitment equivalent to the commitment for a new build plant is able to obtain a Reliability Option of up to 10-years. A Reliability Option of up to 10-years should not be available for plant undertaking minor refurbishment.

Costs of genuine new build capacity

5.2.4 The threshold should serve as a reasonable proxy for the financial commitment incurred for new build capacity, but should not penalise investors who are able to build efficiently at low capital cost, including re-using existing infrastructure.

5.2.5 The SEM Committee is considering setting the financial threshold at a value related to the gross investment cost of the best new entrant, and proposes to use the existing SEM process to determine the Best New Entrant (BNE).

5.2.6 In September 2015, the SEM Committee estimated the investment cost for the best new entrant as €132.7m for a 195.7 nameplate MW plant. This includes an estimated €1m of site procurement costs, €16.5m of electrical connection costs and €0.5m of water connection costs which may not have to be incurred by an investor on an existing site. This would reduce the cost for an investor replacing existing capacity, but still making a substantial financial commitment to €114.7m. This equates to around €586,000 per MW or €586/kW of nameplate capacity. Based on a de-rating factor of 95% for the best new entrant plant, this equates to about €619/kW of de-rated capacity.

5.2.7 The above analysis relates primarily to conventional generation technologies, such as the OCGT technology employed by the current reference BNE plant. Other capacity (e.g. wind, battery storage) which may have different gross investment costs.

International comparisons

5.2.8 We have looked at international comparisons of the financial thresholds used to decide whether a longer-term capacity price guarantee is given in US and GB capacity auctions. Key findings are that:

- A 3-year contract is available to investors spending more than approximately €160-180/kW in GB, but to obtain a 15-year contract, an investor must spend a minimum of around €320-350/kW[22];
- ISO New England allows new capacity resources to guarantee the forward capacity price up to 7 years. Some existing generators can also qualify as new resources if they meet certain criteria[23], some of which are financial. [Up to 7 year contracts] are available for repowering or incremental capacity investing around €270/MW and for investors investing €140/MW for environmental compliance reasons.

Table 3: Required investment to meet financial thresholds in other markets

GB 2015 T-4 Auction (in 2014/15 prices for 2019/20 delivery)

Financial thresholds…	GBP/kW	EUR/kW
Refurbishing capacity	130	179
New build capacity	255	352

ISO NE Current (22/07/2016)

Financial thresholds…	USD/kW	EUR/kW
Repowering capacity	296	269
Incremental capacity	296	269
Environmental compliance	154	140

Indicative value

5.2.9 The above analysis suggests that setting the New Capacity Investment Rate Threshold at around 50% of the BNE gross investment cost would result with a threshold broadly in line with international norms. On this basis, the value would be approximately **€310/kW of de-rated capacity**, if this approach had hypothetically been applied in 2016.

5.2.10 We seek further feedback from stakeholders on the appropriateness of setting the value at this level.

5.3 TERMINATION FEES AND PERFORMANCE BONDS

Termination fees for New Build Capacity

5.3.1 CRM Decision 2 (SEM-16-022) noted that it is important that a new build project be required to pay a Termination Fee, if it fails to deliver capacity, and that it should provide a Performance Bond in advance of the auction as surety that it can cover the Termination Fee. The Termination Fee will be payable if the project:

[22] In GB, the Government defines the following financial thresholds (in 2012 prices) for the December 2014 T-4 auction, i.e. for delivery of Capacity in 2018/19. To qualify as: Refurbishing Capacity, and be eligible for a 3-year contract: an investor needs to meet a minimum financial threshold of £125/kW. This equated to approximately €160/kW at the time of the auction; New Build Capacity, and be eligible for a 15-year contract: an investor needs to meet a minimum financial threshold of £250/kW This equated to €320/kW at the time of the auction. In the 2015, the Government set the thresholds as £130/kW and £255/kW in 2014/15 prices, for both the T-4 auctions for capacity delivery in 2019/20 and the T-1 auctions for capacity delivery in 2016/17. This equated to €180/kW and €350/kW at the time of the T-4 auction respectively.

23 See http://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators

- Fails to achieve the Substantial Financial Completion[24] milestone by the given date; or
- Fails to achieve Substantial Completion[25] by the Long Stop Date; or
- Submits false or misleading information in the pre-qualification process.

5.3.2 In SEM-16-022, the SEM Committee decided that the level of Termination Fee (and hence Performance Bond) should rise progressively over the lifetime of a project to build new capacity. Specifically, it stated that:

- It should start at a low level and increase progressively through the lifecycle of a project. This has the attraction of providing incentives for failing projects to declare their failure early – and so avoid increased Termination Fees and Performance Bonds; and
- It should reach its full level just before the last routine event through which alternative capacity could be procured to replace a failing project. This will be the point at which the capacity requirement is set for the T-1 auction covering the first year in which the relevant plant could (if commissioned) receive option fees.
- The "full level" of the termination fee (and hence Performance Bond) should be set based on analysis of:
  - The cost to consumers of undelivered capacity;
  - The level of liquidated damages available from a typical EPC Contract; and
  - The level of penalties for undelivered capacity to which an existing unit would be exposed.

5.3.3 SEM-16-022 stated that the SEM Committee's initial analysis of these values indicates a value in the range of €47/kW to €55/kW based upon some high level estimates which indicated that:

- Equity: The cost to consumers of failure to deliver a project is approximately €55/kW[26], hence equity consideration would indicate a value of €55/kW.
- Competition and security of supply: Following CRM Consultation 2 (SEM-15-104), respondents argued that the Termination Fee and associated Performance Bond may act as a barrier to entry for new capacity, with a consequential impact on the competition and security of supply criteria. In CRM Decision 2, the SEM Committee stated that it believes this will not occur if Termination Fees are within the liquidated damages for the underlying EPC[27] contract, which the new capacity provider can recover from contractors. The argument is that, the most likely reason for the failure of a project to deliver in time is the failure of the EPC contractors to deliver, and if the capacity provider can pay the Termination Fee out of liquidated damages recoverable from the EPC contractor, the Termination Fee should not be a barrier to entry. In this

24 The definition of Substantial Financial Completion is being developed within the Rules Working Group, but requires all the Major Contracts and financing arrangements are in place and evidence of this is provided, and that the Party has sufficient financial resources available to it to meet the Total Project Spend

25 The definition of Substantial Completion is being developed within the Rules Working Group, but requires that the works are complete, the new capacity has undergone commissioning testing and has achieved Operational Certification (under the relevant Grid Code) that confirms the ability to deliver (after de-rating) 90% of its awarded capacity

26 TSO analysis for the potential change in LOLE standard from 8 hours to 3 hours suggested that losing 200MW of capacity would create an additional 1000MWh of lost load over the course of a year. I.e. roughly speaking for every 1MW of missing capacity there is an additional 5MWh of lost load. Valuing this lost load at VoLL would suggest a cost to consumer of 55€/kW

27 Engineering, Procurement and Construction Management Contract

respect, the SEM Committee notes that the liquidated damages for the assumed 2013 Best New Entrant would be in the range €47/kW to €94/kW[28].

5.3.4 We note that the indicative numbers provided in SEM-16-022, were broad brush estimates, and based on nameplate MW, whereas the actual Termination Fee and Performance Bond will be levied per MW of de-rated capacity.

5.3.5 The estimate of €47-55/kW was based on the only data available from the TSO at that time. That data estimated the cost to the consumer based on *reduction* in unserved energy from adding a 200MW BNE to the 8 hour LOLE capacity standard, rather than *increase* in unserved energy if a 200MW BNE unit fails to materialise- which would be the impact if a new build generator failed to deliver on its promised capacity.

5.3.6 We now have updated analysis from the TSOs, which allows us to estimate the *increase* in the cost of unserved energy if a 200MW new build unit fails to deliver, and we end up with 200MW of capacity less than the Capacity Requirement. This indicates that a shortfall of 200MW below the Capacity Requirement would be expected to result in an increase in the cost to the consumer (when valued at the VoLL of around €11,000/MWh) of around €27m p.a., i.e. the cost to the consumer is around €135/kW. However, we recognise that if termination fees were set at this level, it would deter investment.

5.3.7 We have looked at international benchmarks to help determine the maximum level of fees that might be consistent with attracting investment.

International benchmarks

5.3.8 SEM-16-022 cited the fact that the GB Termination Fee was originally £5/kW for New Build (approximately €6/kW[29]) at the start of a project rising to £25/kW (approximately €30/kW) later in project delivery. However, following experience where some new build has not delivered, in 2016, the UK Department of Energy and Climate change decided to tighten delivery incentives, and confirmed that it would increase Termination Fees for New Build capacity. Termination fees will now start at £10/kW (approximately €12/kW), and rise in steps to £35/kW (approximately €40/kW) by the Capacity Year in question.

5.3.9 In GB, the termination fees are a function of:

- Timing: the potential timing of the event – i.e. whether the event could occur:
  - Before the T-1 auction (enabling the terminated capacity to be rebought)
  - After the T-1 auction but before the start of the delivery year
  - At any time between the auction and end of the delivery year; and
  - After the delivery year has finished; and

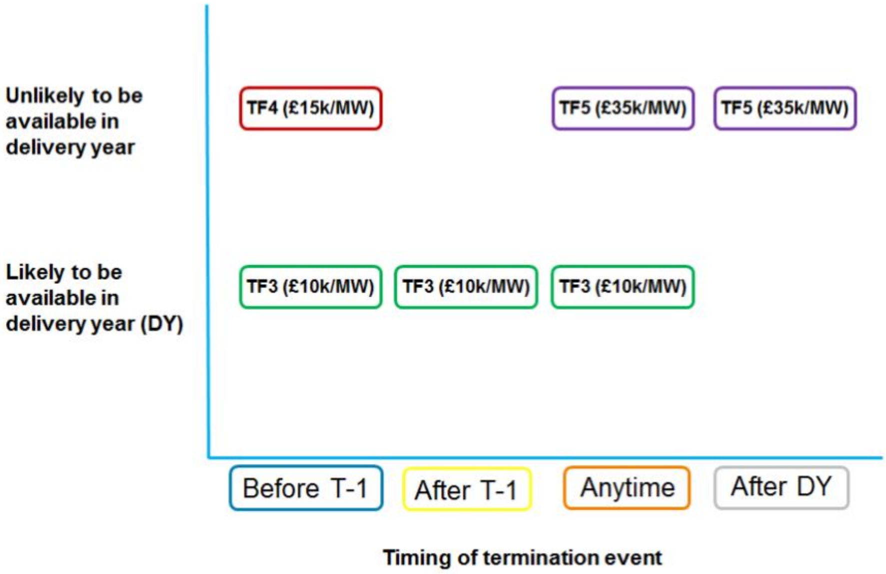
[28] based on EPC liquidated damages being in the order of 10% to 20% of contract value. The 2013 BNE calculation shows an EPC contract cost of €92.5 million for a capacity of 196.5MW., based on a GT13E2 OCGT unit. Using the above percentage range of liquidated damages, a performance bond of 47-94€/kW would be fully covered

[29] At 24/08/2016 exchange rate = £1=€1.172, so £5=€5.86

- The likelihood of the capacity being available in the delivery year despite the termination of their agreement

5.3.10 The new arrangements are summarised in the figure below.

Figure 6: Revised termination fees in GB



5.3.11 The ISO-NE requires sponsors of all new resource projects (demand and supply) to provide financial assurance once they qualify to participate in an upcoming auction. The financial assurance is held until ISO-NE determines that the project has been tested and/ or verified as meeting its full capacity obligation. If the project has met its full obligation on time, the financial assurance obligation is retired. If the project is not delivered in full and on time, the project owner is forced to acquire resources from other parties to compensate for the shortfall. In addition, the financial assurance continues to be offered until the originally bid project is completed. Should the project not be completed by two years after the initial obligated delivery date, the full amount of financial assurance is collected by the ISO-NE (i.e. a termination fee is paid) and the resource is terminated. The current financial assurance requirement is a total of $17.11 per kW not delivered.

5.3.12 PJM also requires that prospective bidders provide financial credit in advance of bidding. The credit requirement is set at the highest expected market clearing price. For the 2016–2017 Base Residential Auction, the pre-clearing credit rate was $36.19 per kW[30]. PJM then imposes a penalty for failing to deliver on capacity commitments. In essence, the bidder does not get paid for the capacity that was not produced and must pay a penalty equal to the greater of (1) 20 percent of the market clearing price; or (2) $20/MW-day, equivalent to $7.30/kW p.a.

Indicative thinking

5.3.13 If the SEM Committee set termination fees at a level which is consistent with consumer detriment resulting from the failure of a new build project to deliver, termination fees would

[30] Note that the credit requirement is adjusted after the market clears, based on the market clearing price, so it is common for credit requirements to be reduced after the auction.

be significantly higher than international norms, and would be highly likely to deter investment. The SEM Committee does not intend to set termination fees this high.

5.3.14 However, it is prudent to learn lessons from other markets, which did not set termination fees high enough initially and suffered as a result of projects failing to deliver. There are advantages in having a termination fee which increases as we approach the start of the delivery year- reflecting the fact that there are fewer and more expensive options to replace capacity closer to real time, and notes that the potential for customer detriment is already high if the new build capacity does not deliver within the first six months of the Capacity Year when the Winter peak occurs.

5.3.15 The SEM Committee sees advantages in a relatively simple formulation of the function, at least initially for the period covered by the transitional auctions when:

- All capacity is likely to be procured in a single T-1 auction (although we have allowed for the potential for 2018/19, 2019/20 and 2020/21 transitional auctions to occur prior to T-1);
- There is limited time for new build to win an auction and build new capacity.

Favoured approach

5.3.16 An appropriate balance between, simplicity, promoting the right incentives and not prohibitively deterring investment is achieved by setting termination fees as follows:

- Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW. A T-1 auction may occur between 2 and 13 months prior to the start of the Capacity Year;
- Termination between 13 months before the start of the Capacity Year and the start of the Capacity Year: €30/kW;
- Termination after the start of the Capacity Year: €40/kW.

5.3.17 For the first transitional auction, given the proposed timings, any New Build winner would immediately be subject to a termination fee of at least €30/kW.

Termination fees for other capacity

5.3.18 There is also a question of whether there should be termination fees for any existing capacity. The rationale for having termination fees for New Build capacity is partly to ensure they have "skin in the game", and partly to ensure that consumers are compensated for the failure of any New Build capacity to deliver.

5.3.19 There may be some capacity that does not meet the criteria to qualify as New Build under the CMC, but has not yet proven its ability to deliver the capacity, any more than a New Build capacity provider who has met the financial criteria by investing more money. For instance, we might be concerned about the capacity delivery risk on:

- Minor upgrades to existing capacity which do not meet the New Capacity Investment Rate Threshold;

- New / unproven DSUs - for instance as cited above, any new supply side bidder in ISO-NE has to provide financial assurance and may lose that financial assurance if it does not deliver on the capacity commitment; and
- Any existing capacity.

5.3.20 Should these classes of bidder be required to pay termination fees, since the risk that they fail to deliver is not necessarily related to the New Build criteria set out in the CMC? Clearly the impact on customers *if* they fail to deliver is the same, but arguably the delivery risk is lower.

5.3.21 In the case of new DSUs, we need to balance the risk to consumers with a desire to promote environmental objectives, and not unduly deter innovative DSU proposals.

5.3.22 There may also be a case for requiring existing capacity to pay termination fees. Clearly, with existing capacity, which has proven its ability to deliver, there is less risk that it could win an auction and then subsequent fail to deliver the capacity for technical reasons. However, there is a risk that if there is no termination fee for existing capacity, an existing capacity provider which is considering closing could regard entering the auction as a free option. This is particularly the case for T-4 auctions, where a bidder may enter a capacity auction and take a gamble on the amount of infra-marginal rent that it is in going to earn in four years. If closer to the time, infra-marginal rent forecast for that plant appear low, it could change its mind, and decide not to honour the Reliability Option that it has signed.

5.3.23 This risk is partially mitigated by the fact that the Grid Code requires Grid connected generators with Registered Capacity greater than 50MW to give 36 months' notice of intention to close, and connected generators with less than 50MW to give 24 months' notice of intention to close. This requirement should have a strong compliance effect in T-1 auctions and the transitional auctions (which may be T-1, but could also be T-2, T-3 for later Capacity Years during the transitional period). However:

- There is still a potential 18-month window between the T-4 auction and 3-year Grid code deadline (T-4 auctions can occur up to 4 years 6 months ahead of the auction);
- The Grid Code requirement does not apply to embedded generation or to DSUs;
- There may be a risk that existing generators with a single plant, have limited other "skin in the game", and the incentives to honour the Reliability Option need to be strengthened.

5.3.24 This risk may also be partially mitigated by the requirement to lodge collateral against difference payments. If the capacity provider has already had to lodge collateral against difference payments, its incentive to exit the market and renege on its Reliability Option may be limited if it still has to make the difference payments from the collateral that it has lodged.

5.3.25 The SEM Committee seeks feedback on whether it is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including:

- Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;
- New / unproven DSUs;

- Any other capacity provider which has not already demonstrated its ability to physically deliver; or even
- All existing capacity.

Performance bonds

5.3.26 Regarding the interaction with Performance Bonds, we welcome views as to whether the performance bond that a bidder is required to put in place should cover 100% of the termination fee payable at any given time? If this approach is followed, for new investment, as the termination fee rises over the course of the project up until delivery, the size of the performance bond should rise commensurately.

5.4 SUMMARY OF QUESTIONS

5.4.1 The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on whether:

A) You agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?

B) You think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.

C) It is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including:
   a. Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;
   b. Unproven DSUs;
   c. Any other capacity provider which has not already demonstrated its ability to physically deliver; or even
   d. All existing capacity

D) Performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?

6. AUCTION PARAMETERS

6.1 INTRODUCTION

6.1.1 In CRM Decision 3 (SEM-16-022), the SEM Committee decide on a number of auction parameters, which need to be set. The key auction parameters and the process for setting them is as follows:

- **Auction Price Cap**. We propose to set the Auction Price Cap as a multiple of Net CONE. The SEM Committee proposes to fix the multiple indefinitely in the February 2017 CRM Parameters decision document, but will re-estimate Net CONE for each transitional auction, and for each subsequent T-4 and T-1 auction, and publish the updated Net CONE value prior to the start of the Qualification Window for each auction;
- Uniform Price-taker Offer Cap, now called the **Existing Capacity Price Cap** within the Capacity Market Code. The Existing Capacity Price Cap will be set in €/kW, and vary by Capacity Year. The SEM Committee will set out its overall methodology for estimating this parameter in the CRM Parameters decision document, but will re-estimate and publish the value of the Existing Capacity Price Cap for each transitional auction, and for each subsequent T-4 and T-1 auction, and publish the updated value prior to the start of the Qualification Window for each auction. The CRM Parameters decision document will set out the value for the first transitional auction Existing Capacity Price Cap, and any existing capacity which considers that its Net Going Forward Costs are greater than the Existing Capacity Price Cap, should apply for a higher unit specific bid limit during auction Qualification Window;
- **Demand curve parameters**. The demand curve parameters refer to the all-island demand curve parameters. As discussed below, there may also be a requirement for locational parameters. The demand curve parameters will be re-estimated for each auction, as they take into account Capacity Year specific factors such as the latest estimate for the Capacity Requirement for the Capacity Year in question, and any multi-year Reliability Options awarded in respect of that Capacity Year in prior auctions. The Capacity Requirement methodology is still being consulted on (see SEM-16-051), and the numbers presented in this document are consistent with the TSOs methodology set out in SEM-16-051a. The CRM parameters decision document will set out the SEM Committee's decision on the methodology for calculating the demand curve parameters, and the provisional demand curve parameters for the 2017/18 transitional auction. However, the actual demand curve to be used in the 2017/18 transitional auction will be published after the completion of the 2017/18 transitional auction Qualification Window, and will be adjusted for the impact of any existing capacity which exercises its discretion not to bid but is still expected to make a capacity contribution[31], and the SEM Committee reserves the right to re-estimate the Capacity Requirement, for instance in response to a materially updated demand

[31] Applies to intermittent generation and non-firm transmission access generation

forecast. The final demand curve parameters for the 2017/18 transitional auction will be published sufficiently prior to the auction date;

6.1.2 **Locational parameters**. In the Local Security of Supply consultation (SEM-16-052), we set out a range of options for how locational constraints would be specified. These included: Option 1, a separate capacity requirement for each constrained capacity area, *measured in MW;* Option 2, a separate capacity requirement for each constrained capacity area, *measured in units;* and Option 3, nested capacity areas. Under any of these options, there are parameters to be set, although as discussed, the form of the parameters may differ depending on the option chosen and the auction design option chosen. SEM Committee may choose not to publish these parameters before the auction if there are concerns that it could increase the ability of bidders to exercise market power. These issues are discussed in section 6.5.

6.2 THE AUCTION PRICE CAP

Background

6.2.1 In CRM Decision 3 (SEM-16-039), the SEM Committee stated that all auctions will employ an Auction Price Cap, which will set a maximum price at which all Qualified Bidders may bid their Qualified Volume. The Auction Price Cap is the maximum price that the auction can clear at.

6.2.1 In practice, since the Existing Capacity Price Cap, or any lower unit specific bid limits will apply to all existing generators and interconnectors, the Auction Price Cap will only be binding on new build capacity and existing DSUs.

6.2.2 In SEM-16-039, the SEM Committee further stated that:

- Responses to CRM Consultation 3 (SEM-16-010) generally favoured an Auction Price Cap based on a multiple of the Net CONE, and their preference for the multiple to be set in the range of 1.5 to 2 times Net CONE;
- The SEM Committee will make a final decision on the level of the Auction Price Cap for the transitional auctions as part of the forthcoming CRM parameters consultation; and
- The SEM Committee notes that the current level of average capacity price (i.e. 1 x Net CONE) has been effective in delivering sufficient capacity in the SEM.

6.2.3 In this Section, we address some generic principles which will apply in setting the Auction Price Cap in all I-SEM CRM auctions, and some specific issues which relate to how the solution will be applied practically for the first transitional auction.

General principles in setting Auction Price Cap parameter

6.2.4 As set out in CRM Consultation 3 (SEM-16-010), in all I-SEM CRM auctions, the Auction Price Cap parameter should be set at a level which balances:

- The risk that the Auction Price Cap is set at too low a level to incentivise new investment when it is needed, jeopardising **system security**; and

- The risk that the Auction Price Cap is set at too high a level, allowing market participants with market power to abuse their market power and drive up the auction clearing price, i.e. have negative effects with respect to **competition** and **efficiency objectives**.

6.2.5 The GB and a number of US capacity auctions set an Auction Price Cap as a function of an administratively estimated Net Cost of New Entry (Net CONE). Net CONE is typically defined as the estimated fixed costs of a Best New Entrant (BNE) Peaking Plant, minus revenues from infra-marginal rent in the energy market and ancillary services.

6.2.6 In practice Net CONE is calculated in the SEM, and in other markets as:

- Gross CONE, which has two key elements:
  - Investment costs, including depreciation, interest financing and return on capital on investment; and
  - Fixed Operating and Maintenance (FOM) costs, including insurance and fixed TUoS costs.
- Net of infra-marginal rent earned by the reference new entry plant from energy income and ancillary service income.

6.2.7 However, there are the following outstanding questions to be resolved in setting the Auction Price Cap. The following issues arise:

- Are any adjustments required to be made to the way in which Net CONE is calculated? There are three potential reasons why it may be appropriate to make changes to the Net CONE calculation. These issues are methodological issues that arise as a result of the move from the SEM to the I-SEM, and apply in general to all I-SEM CRM auctions:
  - An adjustment to outage assumption for infra-marginal rent may be appropriate to align the assumptions with the de-rating decisions;
  - Adjustments to reflect the introduction of ASP, combined with the Reliability Option, which will have a number of effects on the infra-marginal rent (IMR) that a BNE plant can earn;
  - To adjust from nameplate capacity to de-rated capacity. The SEM Net CONE is implicitly expressed in €/kW of nameplate capacity, and Reliability Options will be paid per unit of de-rated capacity;
- What multiple of Net CONE is appropriate? We will set a value for the first transitional auction which we expect to apply for subsequent auctions, but like other elements of this value it will be subject to review, based on the experience of the first auction.

Outage rates

6.2.8 The current BNE calculation assumes a forced outage rate of 5.91% for the BNE reference plant in calculating IMR, and a forced outage rate of 5% for ancillary services. Given the TSOs proposed I-SEM CRM de-rating factor 95.0% for the reference BNE plant, we would propose to standardise on a forced outage rate of 5.0% for all elements of the calculation. We estimate that the reduction in the assumed outage rate would add around €0.06/MWh to IMR to the 2017 BNE estimate of €6.29/MWh.

Impact of Reliability Option difference payments and ASP

6.2.9 If a capacity provider has a Reliability Option it is required to make difference payments, when the relevant energy price exceeds the RO Strike Price. The Reliability Option reduces the IMR that a peaking generator can earn, so should be taken account of in a revised Net CONE calculation. The current Net CONE calculation assumes that a peaking generator earns the Pool Price Cap (currently €1,000/MWh) for 8 hours, and so earns infra-marginal rent equal to the difference between the short run marginal cost of the reference BNE plant and €1,000 for 8 hours in the year.

6.2.10 The Reliability Option Strike Price, which will cap the infra-marginal rent of a generator with a Reliability Option on the proportion of the capacity covered by the Reliability Option, will be a variable price. However, if the DSU floor price is set at €500/MWh as discussed in section 4.2, unless there is a very significant change in fuel prices, the Reliability Option Strike Price will be €500/MWh most of the time. We will use the €500/MWh value in place of the existing €1,000/MWh Pool Price Cap in the revised BNE calculation, to calculate the IMR that the BNE plant can earn on the portion of the capacity covered by the Reliability Option. We will also need to take into account the fact that:

- The BNE plant will be exposed to difference payments on the full ASP when on forced outage; but
- Can earn IMR at the Full ASP on the de-rated component of its capacity.

6.2.11 Introducing the Partial ASP function may mean that there are more hours when prices are lifted to €500/MWh or above.

6.2.12 The introduction of Partial ASP when short term operating reserve falls below the target (see Section 2, but approximately 500MW) means that even if the capacity standard of 8 hours LoLE is met, there may be more than 8 hours when ASP applies and a peaking generator earns infra-marginal rent (IMR) up to the Reliability Option Strike Price. As illustrated in Figure 4 of section 2.2, if short term operating reserve falls as low as 500MW, LoLP is already around 65%. We will assume that that there are likely to be only around 4 hours (35%/65% x 8 hours) in which ASP applies but in which lost load does not. The average value of the Partial ASP will depend on which option for the ASP function described in Section 2 is selected, but for indicative purposes in this document, we will use a value of €1500/MWh (50% of Full ASP). This means the IMR calculation will also assume that there will be 4 hours of Partial ASP at €1500/MWh. These changes result in an indicative value of IMR of €4.03/MWh for the BNE plant, compared to €6.35/MWh[32], without the Reliability Option and ASP.

6.2.13 The calculation of these values is shown in Appendix C.

Converting from nameplate capacity to de-rated capacity

[32] But after the change in Forced Outage Rate to 5% from 5.91%

6.2.14 The current BNE price is implicitly expressed per unit of nameplate MW, with an appropriate adjustment for outages, so that the reference unit can recover its missing money if it is paid at the Net CONE price on 100% of its nameplate capacity for time it is not expected to be on outage.

6.2.15 In the I-SEM CRM, a Capacity Market Unit can only obtain a Reliability Option equal to its derating factor x nameplate capacity. Therefore, in the I-SEM, to calculate the BNE price per unit of de-rated capacity in €/kW we will adjust the Net CONE to reflect the fact that a capacity provider can only earn Reliability Option fees on its de-rated volume.

6.2.16 SEM-16-051a set out the TSOs' proposal to apply a 95.0% de-rating factor to Gas Turbine plant with a capacity of between 100MW and 200MW. If the TSOs proposals are accepted as part of the SEM Committee's De-rating and Capacity Requirement Decision, then this would result in the Net CONE in nameplate MW being converted to de-rated MW by diving by 0.95.

6.2.17 The rationale for this adjustment can be explained as follows. In the SEM, a capacity provider can only earn availability payments when it is available, and its availability will be net of forced and scheduled outages. However, in the SEM, the capacity payments pot is fixed as the product of Net CONE per unit of nameplate capacity and the Capacity Requirement in nameplate MW. If all SEM units have a 90% availability, since the pot of payments is fixed, then the average payment per MW of availability is increased by 100%/90% and a unit with 90% availability would receive Net CONE if installed capacity was equal to the Capacity Requirement. However, consider if the I-SEM CRM, was set at €71.45/kW, the 2017 Net CONE. The 195.7 MW BNE reference plant would be de-rated to 185.9MW. If the auction clears at Net CONE, the BNE reference plant would receive Net CONE on 185.7MW only, not sufficient to earn Net CONE on all 195MW of its nameplate capacity.

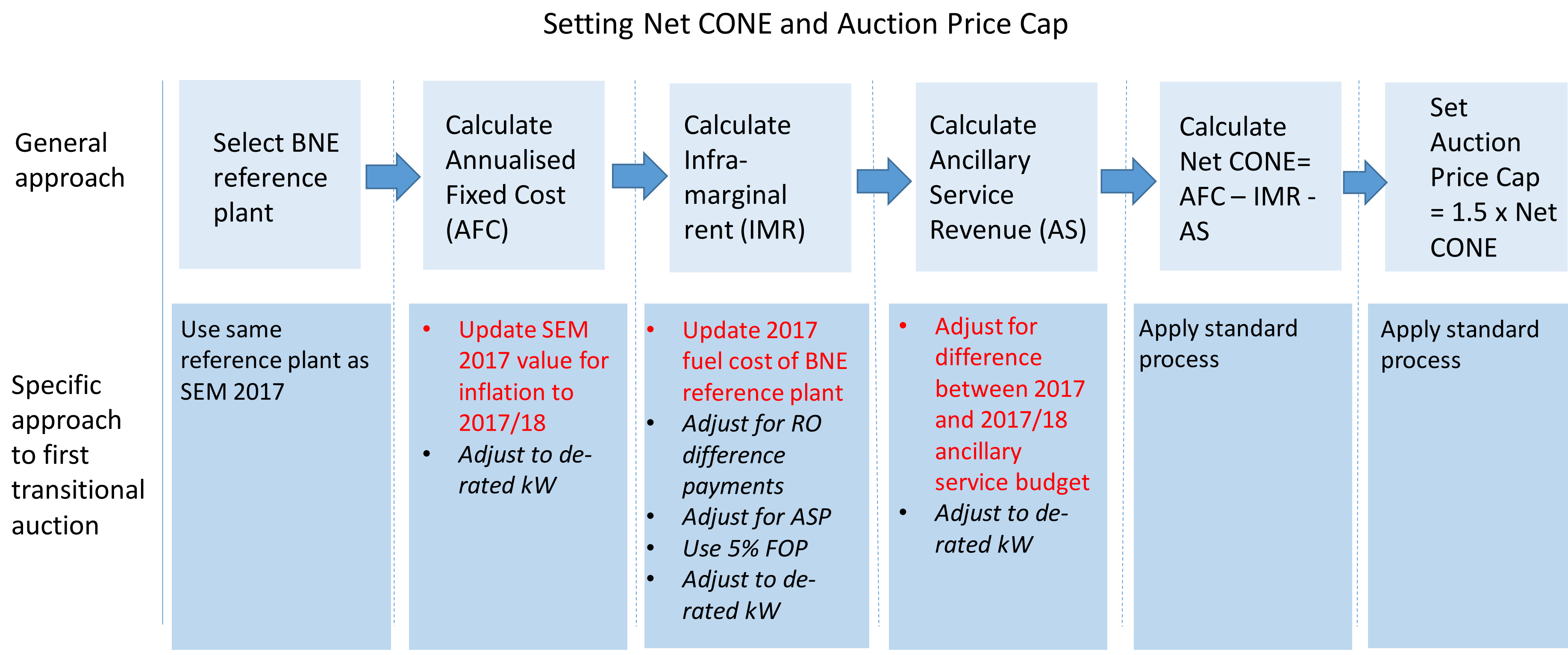
Multiple of Net CONE

6.2.18 As discussed in SEM-16-010, US and GB capacity markets typically employ an Auction Price Cap of 1.5 to 2 x Net CONE, and setting the Auction Price Cap at this level allows for a margin of error in the calculation of Net CONE.

6.2.19 The SEM Committee favours setting the multiple at the lower end of this range (1.5 x Net CONE) for the foreseeable future, since the experience of the SEM is that capacity providers have found a capacity payment of less than 1 x Net CONE adequate to cover their "missing money". There is currently around 10,800 MW of installed capacity[33] according to the 2016 Generation Capacity Statement, whereas the 2016 Capacity Requirement is 7070MW. This means that the current level of capacity payments has resulted in significantly more capacity than required, despite each MW of capacity getting significantly less than Net CONE with an Annual Capacity Payment Sum designed for 7,070MW shared between 10,800MW.

[33] Including a 500MW capacity credit for wind

Figure 7: Setting Net CONE and Auction Price Cap



Summary and Indicative values

6.2.20 The general approach to setting Net CONE and the Auction Price Cap is summarised in Figure 7 above. Figure 7 also summarises the proposed approach to updating Net CONE for the first transitional auction.

6.2.21 Based on the adjustments outlined above, indicatively **Net CONE for 2017/18 would be €77.81/de-rated kW/year**, compared with the SEM 2017 value of €71.44/kW of nameplate capacity.

6.2.22 The assumption that infra-marginal rent is capped at €500/MWh adds €3.76/kW, and the change to expressing Net CONE adds €3.96/kW in aggregate to Net CONE[34]. However, the assumption that the introduction of Partial ASP adds 4 hours where Partial ASP is greater than €500/MWh, adds an estimated €1.27/kW to IMR, and reduces Net CONE commensurately These numbers are before any adjustments for inflation.

Table 4: Indicative Adjustments to Net CONE

	SEM	I-SEM	Analysis of difference	
Annualised fixed cost	85.08	89.56		
			4.48	Shift from nameplate to derated kW
Infra-marginal rent	-6.29	- 4.03		
			-0.06	Use 5% FOP, not 5.91%
			2.53	Impact of ASP and RO difference payments
			-0.20	Shift from nameplate to derated kW
Ancillary services	-7.35	- 7.73		
			-0.39	Shift from nameplate to derated kW
Total	71.45	77.81	6.36	

6.2.23 Therefore, if the Auction Price Cap is set at 1.5 x Net CONE, **the indicative value of the Auction Price Cap would be €116.71/de-rated kW p.a**. Note that this figure is indicative only, and if the changes consulted on in this paper were adopted, it would still be necessary to update the indicative Net CONE, and hence the Auction Price Cap for *inter alia,* the following adjustments highlighted in red, shown in Figure 7:

- Differences in infra-marginal rent due to changes in the fuel cost of the BNE reference plant;
- Inflation from Calendar 2017 to Capacity Year 2017/18, which impact on fixed costs;
- Changes in ancillary service revenue between Calendar 2017 and Capacity Year 2017/18.

6.2.24 We would expect to update these values before publishing the Auction Price Cap for the first transitional auction.

[34] 4.48-0.13- 0.39=3.96

6.3 EXISTING CAPACITY PRICE CAP (UNIFORM PRICE-TAKER OFFER CAP)

Background

6.3.1 In CRM Decision 3 (SEM-16-039), the SEM Committee decided that the following bid limits should apply to existing generators, in addition to the Auction Price Cap:

- A uniform (i.e. non-technology specific) Price-taker Offer Cap. This parameter has been termed the Existing Capacity Price Cap in the Capacity Market Code drafting. All Existing[35] Generators will be required to bid their full Qualified Volume into the transitional auctions and the T-4 auctions at a price no higher than the Existing Capacity Price Cap in the Capacity Market Code drafting (specified in €/MW or £/MW), unless they apply for higher bid limit as set out below, or submit an Opt-Out Notification on the grounds that they are going to close before the end of the relevant Capacity Year;
- Right to apply for higher bid limit: Where an existing generation Capacity Market Unit (CMU) is able to evidence the fact that it has higher avoidable Net Going Forward costs than the Price-taker Offer Cap, it will be able to apply to the CRM Delivery Body to be allowed to submit a higher Bid Limit– up to the level of the unit's individual Net Going Forward Costs. The CRM Delivery Body will review the application and make a recommendation to the SEM Committee whether to accept or reject the application, and what level of Net Going Forward Costs are reasonable for that unit. The SEM Committee may then set a Unit Specific Bid Limit specific to that unit for that auction, at a higher level than the Existing Capacity Price Cap, at a level commensurate with its view of the unit's Net Going Forward costs. DSUs are not subject to the Existing Capacity Price Cap.

6.3.2 In addition, in the Local Security of Supply consultation (SEM-16-052), considered the option of implementing unit specific bid limits for any plant required for local security of supply reasons.

6.3.3 To implement these bid limits, the SEM Committee needs to:

- Set the Existing Capacity Price Cap; and
- Define Net Going Forward Costs and the methodology / process for calculating Net Going Forward Costs for any existing capacity wishing to apply for a higher unit specific limit.

Key principles in setting level of Existing Capacity Price Cap

6.3.4 The Existing Capacity Price Cap for the first transitional auction are expected to be set at a level which allows the vast majority of existing capacity to bid its Net Going Forward Costs into the auction, without having to apply for a higher unit specific bid limit. Bearing in mind that currently available capacity comfortably exceeds the all-island capacity requirement, the SEM Committee does not see the need to set the Existing Capacity Price Cap at a level equal to or

[35] Generators which meet the criteria for new build generation will not be subject to the Price-taker Offer Cap and may bid at a price up to the Auction Price Cap

higher than the Net Going Forward costs of all capacity on the island of Ireland. The SEM Committee envisages that the Existing Capacity Price Cap will be set at a level which will allow the majority of existing de-rated capacity to meet the all-island capacity requirement[36] to bid at a price at least equal to its unit specific Net Going Forward Costs. For the first transitional auction, the Existing Capacity Price Cap should not be set higher than Net CONE, as this would allow existing capacity to exercise any market power they have due to the lack of time for new entrants to build. Given the current excess of capacity over the Capacity Requirement, we anticipate that this value will be less than Net CONE.

6.3.5 To set the Existing Capacity Price Cap at an appropriate level, the SEM Committee needs to:

- Define the methodology and approach for estimating Net Going Forward Costs; and
- Estimate the range of Net Going Forward Costs of existing plant.
- Consider what plant exit should be assumed, if any, in the calculation of infra-marginal rent (a component of Net Going Forward Costs) as a result of the move to the volume based I-SEM CRM.

Definition and approach to setting Net Going Forward costs

6.3.6 The definition of Net Going Forward Costs will be an input into:

- The setting of the Existing Capacity Price Cap. Although we propose to set the cap as a multiple of net CONE, in the first transitional auction, it will be set at a multiple which accommodates the vast majority of plant required to meet the Capacity Requirement;
- The unit specific Bid Limit where a unit exercises its right to apply for a higher unit specific limit. In assessing the application, the RAs will take into account the unit's estimated Net Going Forward Costs.

6.3.7 The SEM Committee is considering defining Net Going Forward Costs for a capacity provider as:

Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

6.3.8 In the absence of a capacity remuneration mechanism, an existing peaking plant which only runs for a very short period in a year, would need to cover its fixed operating costs through infra-marginal rent earned in the energy and ancillary services market. If it did not, it would be economically rational for it to exit the market.

6.3.9 The definition of fixed operating costs does not include any element to cover sunk costs investment costs - depreciation or return on capital. New investors will also need to earn enough money to cover depreciation costs and provide a reasonable expectation of return on capital, but this is not strictly necessary for sunk investments, and in a competitive market with excess capacity, we would expect prices to fall towards the value of missing money for existing investors (or lower if new entrants can undercut them by being more efficient in the energy market and earning greater infra-marginal rent).

[36] Taking appropriate account if the expected de-rated contribution of interconnectors and DSU

6.3.10 Where the generator runs and provides energy or ancillary services, we would expect it to cover the variable fuel costs and other variable costs through energy and ancillary service revenue, and if the revenue exceeds its costs, i.e. there is infra-marginal rent, this infra-marginal rent reduces the "missing money" which a generator needs to earn from the capacity mechanism to justify continued operation. Where the infra-marginal rent exceeds the fixed operating costs, an existing generator does not need have any "missing money".

6.3.11 However, even if a generator has no "missing money", it may decide to include a component in its bid to cover Reliability Option difference payments. A capacity provider will incur difference payments if they win a Reliability Option, even if they deliver capacity as desired, whereas losing bidders will not be liable for difference payments. A generator may prefer to bid at a price which will allows it to cover the resulting difference payments, rather than offset this liability against infra-marginal rent in constructing its bid.

6.3.12 For this reason, we have specified the formula to include infra-marginal rent *gross* of scarcity rents in excess of the Strike Price inside the Max [ ] element of the formula, so that the following element of the formula represents the missing money of a generator without a Reliability Option:

Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets

6.3.13 If this element of the formula is zero or negative, then the generator has no missing money, without a Reliability Option. However, consider the case of a generator whose infra-marginal easily covers its fixed operating costs. Suppose that it expects to have 8 hours per year where it earns Full ASP of €3,000/MWh and 4 hours where it earns a lower ASP averaging €2,000/MWh. Suppose further that the Strike price is €500/MWh. Then ASP contributes €26,000/MW/year of gross infra-marginal rent[37], which would be taken away from the generator in Reliability Option difference payments if it wins the auction. Even if it has a large infra-marginal rent (more than €26,000, for instance), it may want to bid a minimum price of €26/kW/year to ensure that it did not lose money from winning the auction (relative to a counterfactual of losing the auction, and retaining the full value of ASP earned in the energy market), hence the rationale for taking the difference payment outside the Max element of the formula.

6.3.14 To estimate the impact of difference payments on Net Going Forward Costs in the first transitional auction, we need to include assumptions about the incidence of ASP. Whilst the capacity standard might indicate 8 hours of lost load, and LOLP modelling values might indicate a further 4 hours of scarcity short of lost load, using these assumptions is likely to significantly over-estimate expectations of difference payments in 2017/18, for number of reasons. Firstly, there is currently significantly more operational capacity than Capacity Requirement and most of this capacity has to give 36-months' notice of its intention to close. Secondly, in the 2017/18 Capacity Year we will be setting the demand curve based on the 2020/21 Capacity Requirement. Thirdly, the deployment of a sloping demand curve could lead

[37] Difference payments = (€3,000/MWh FASP - €500/MWh Strike Price) x 8 hours of lost load + (€2,000/MWh ASP - €500/MWh Strike Price) x 4 hours = €26,000/MW/year = €26/kW/year

to the volume of Reliability Options exceeding the 2020/21 Capacity Requirement by up to 20% (see Section 6.4).

Process and data to set Existing Capacity Price Cap

6.3.15 The SEM Committee intends to use the current SEM Generator Financial Reporting data as the basis for estimating fixed operating costs[38]. The SEM Generator Financial reporting data contains a unit level historical breakdown of the costs of generators into Fuel Operating Costs, and Non-Fuel Operating Costs. Whilst the fuel / non-fuel operating cost breakdown may be similar to the fixed/ variable breakdown, there may be some adjustments that need to be made to the Generator Financial Returns to align the reported numbers to the fixed/variable definition, and the SEM Committee seeks feedback on what adjustments are appropriate.

6.3.16 The SEM Committee does not publish site specific information on generator financial performance, gained from the regulatory reporting template, to ensure that no commercially sensitive data is made available publicly. Instead only aggregated data showing financial information for groups of generators (for example by fuel type or generator size) will be published, where such information does not enable commercially sensitive information to be inferred. However, the SEM Committee will use this site-specific information in setting the Existing Capacity Price Cap.

6.3.17 The SEM Committee may also undertake some adjustments to reported data, where for instance, it is of the view that cost allocations between units are not appropriate, or that the reported results are not consistent with efficient operation of the assets in question.

6.3.18 In setting the Existing Capacity Price Cap there will be a need to:

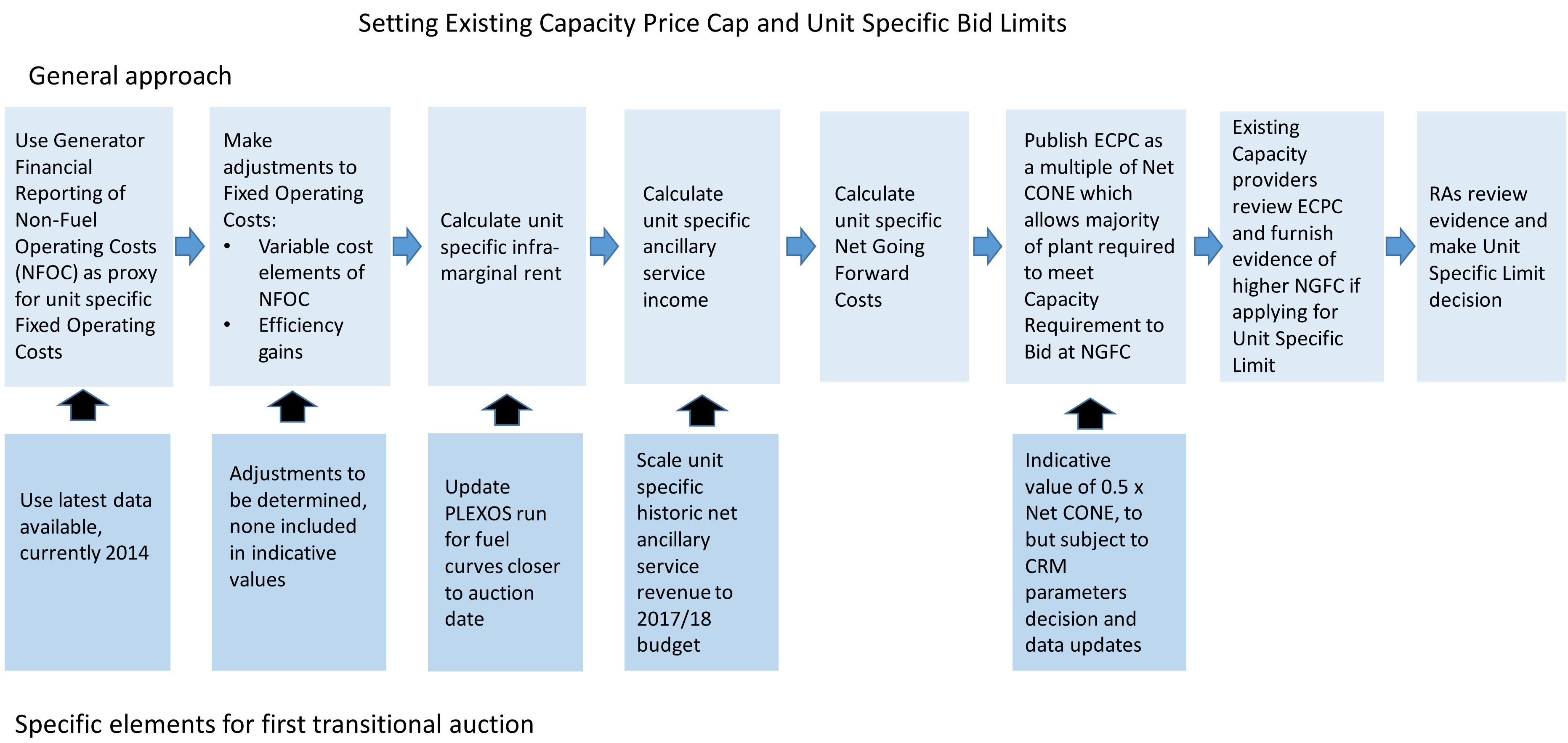
- Undertake PLEXOS modelling of I-SEM energy revenues for the relevant Capacity Year, using appropriate fuel and carbon forward price curves for the relevant Capacity Year;
- Project ancillary service revenues, taking appropriate account of the increase in the DS3 budget for each relevant year;
- Make relevant projections of change in costs, such as inflation and known changes in TUoS charges, etc.

6.3.19 Whilst it is envisaged that this definition and approach will be used for the second and subsequent transitional auctions, and for the T-4 auctions, the SEM Committee will review this approach in the light of the experience of the first transitional auction.

6.3.20 The general process and specific issues for the first transitional auction are summarised in Figure 8.

[38] See Generator Financial Reporting in the SEM, a SEM Committee Decision Paper, 2nd May 2012 (SEM-12-027)

Figure 8: Setting the ECPC and unit specific bid limits



Evidence on Fixed Operating Costs from SEM Generator Financial Reporting

6.3.21 The RAs have collated historical regulatory returns data for 2012 to 2014, using Non-Fuel Operating Costs as a proxy for Fixed Operating & Maintenance costs, as shown in Figure 9. To preserve the confidentiality of data from Regulatory Returns, the data below is presented at an aggregated level by fuel type only. Also to preserve confidentiality, we have not further disaggregated the data by technology although there are significant differences between, for instance, CCGT and OCGT and between distillate and other oil plant.

6.3.22 The data shows significant variability between years, and between different units in the fuel type grouping. Whilst we have not shown the dispersion of Non-Fuel Operation Cost within a particular grouping in the table, it is not uncommon to see variation of ±€20/kW in these costs within a particular fuel type grouping (even after disaggregating gas into CCGT and OCGT and between types of oil plant) and for a particular year. In some cases, the variation may be partly dependent on how the generator in question has chosen to allocate station overheads to individual units within a station.

Figure 9: Average Non-Fuel Operating Cost by fuel

<table>
<tr><th>Fuel Category</th><th>NFOC per MW 2012</th><th>NFOC per MW 2013</th><th>NFOC per MW 2014</th><th>Average NFOC per MW 2012 - 2014</th></tr>
<tr><td>Hydro</td><td>125.00</td><td>97.00</td><td>104.00</td><td>108.67</td></tr>
<tr><td>Pumped Storage</td><td>77.00</td><td>60.00</td><td>60.00</td><td>65.67</td></tr>
<tr><td>Coal</td><td>112.00</td><td>91.00</td><td>115.00</td><td>106.00</td></tr>
<tr><td>Distilate</td><td>13.00</td><td>12.00</td><td rowspan="2">21.00</td><td rowspan="2">25.18</td></tr>
<tr><td>Oil</td><td>41.00</td><td>33.00</td></tr>
<tr><td>Gas</td><td>55.00</td><td>50.00</td><td>49.00</td><td>51.33</td></tr>
</table>

6.3.23 We note however, that there may be reasons why the SEM Committee could choose to make adjustments to the historical NFOC cost numbers in setting the Existing Capacity Price Cap. These include:

- The above numbers use NFOC as a proxy for Fixed Operating & Maintenance (FOM) costs, which a generator may not be able to recover in a competitive energy market. However, it is likely that the NFOC contains a proportion of Variable Operating & Maintenance (VOM) costs which can be recovered via the energy or ancillary service markets, as well as FOM costs. There may be an argument that for some plant types, e.g. coal and CCGT, that a significant proportion of maintenance costs and certainly some consumables and waste costs are not really part of net going forward costs, but would be included in non-fuel costs. However, for plant that runs infrequently, such as gas fired OCGTs and oil fired plant which is high up the energy merit order, the variable costs may not be significant. Whilst this proportion may be relatively small, there is no breakdown of this data in the SEM Generator Financial Reporting which allows the breakdown to be calculated directly;
- The lack of competition in the existing SEM capacity market has not placed sufficient competitive pressure on some generators to reduce FOM costs, and in the absence of competitive pressure, they have not sought to reduce costs to more efficient levels to maximise profit. It might be the case that with the move to a competitive I-SEM CRM,

some generators may be able to realise efficiency gains in FOM costs. In this regard we note that:

- As set out later in this section, estimated SEM NFOC/FOM costs are significantly greater than costs in other markets for which data is readily available.
- There is a trend towards a reduction in Non-Fuel Operating Costs in the data in Figure 9. We seek explanation of why this is, and whether the trend should be expected to continue.

6.3.24 We note that a significant proportion of plant in the SEM is relatively old, and would inevitably have high FOM costs even if operated and maintained as efficiently as reasonably possible. To the extent that existing SEM plant has unavoidably high FOM costs, the unavoidable costs should be reflected in the Existing Capacity Price Cap, which increases the possibility that new plant can enter the market and compete. However, to the extent that high historical cost structures are due to the lack of competition in the SEM Capacity Payment Mechanism, the SEM committee could choose not to reflect inefficiently incurred costs.

International benchmarks of fixed operating and maintenance costs

6.3.25 We have researched evidence from other markets, such as various GB, US and Australia markets, which publish data on Non-Fuel Operating Costs (NFOC) and Fixed Operating and Maintenance (FOM) to provide an alternative view on values reported by existing generators in SEM Generator Financial Reporting. In some cases, this data is used for similar regulatory control purposes, as will be employed on the I-SEM- i.e. setting capacity auction bid caps. In other cases, the data is published for information only.

6.3.26 The data predominantly focuses on peaking plant, either aero-derivative gas turbines or frame gas turbines, which are most likely to have missing money – and which are most analogous to the “other gas fired category”, the highest SEM NFOC category identified in Figure 9.

6.3.27 The international data may be used, where relevant, to help us form a view of:

- Whether adjustments should be made to apportion NFOCs into FOM (which we would expect to be reflected in capacity auction bids) and Variable Operating and Maintenance Costs (VOMs), which, being a variable function of output, we would expect to be recovered in the energy market. and
- To help form a view on whether the SEM CPM, which did not involve the same competitive processes as the I-SEM CRM has allowed generators to operate inefficiently with high fixed costs, when going forward, it would be possible to reduce fixed costs. Whilst we note that localised factors (such as property taxes, wage rates) may influence comparison, never the less, the data provides a benchmark.

6.3.28 PJM provide the best explanation of which costs they regard as fixed, and which they regard as variable. PJM state the following:

- Fixed Operating and Maintenance (FOM) cost covers: LTSAs (Long Term Service Agreements), labour, certain consumables, maintenance and minor repairs, admin and general, asset management, property taxes, insurance and working capital;

- Variable Operating Maintenance (VOM) costs covers major maintenance (which is start-based), and consumables and waste disposal which is assumed related to running.

6.3.29 The table below summarises the data on FOMs and VOMs from other markets for Gas Turbines and how this compares with values for NFOCs reported by SEM generators. Some markets produce separate estimates for aero-engine derivative and frame GTs, with frame GTs such as the SEM BNE Alstom GT13E2 typically having significantly lower costs.

Table 5: International benchmarks of NFOCs and FOM costs

Market/indicator	Assumed FOM and VOM costs p.a.	Comments
SEM Generator Financial Reporting	Oil NFOC =€39/kW CCGT NFOC = €49/kW Other gas NFOC = €64/kW	2014 data for existing plant
SEM BNE	FOM: €26.5/kW for BNE reference plant a Frame OCGT	For new plant
GB	OCGT NFOC = £14/kW (€16/kW)[39]	For new plant
PJM	GT FOM costs: US$15.4-25.6/kW for (in 2018$). Equivalent to €14-23/kW	Data prepared for PJM to support the regulatory setting of Net CONE for capacity auction market. Almost all the variation is in local property taxes
Western Electricity Co-ordinating Council (WECC), 14 western US states, 2 Canadian provinces)	Aero-derivative GTs: FOM costs in range US$12-29/kW (US$15=€11/kW was recommended benchmark) Frame GTs: FOM costs in range US$ 4-12$/kW (US$9= €8/kW recommended)[40]	
California Electricity Council – part of WECC	FOM costs: in range US$25-28, (€22-25/kW) for aero-derivative GTs[41]	All O&M costs assumed fixed
NREL	FOM cost: US$5.26 (€4/kW), based on a GE 7FA or equivalent (211MW) VOM cost: US$30/kW based on same unit [42]	FOM costs estimated to be only 15% of total operating and maintenance costs.
Co2CRC (Australian Annual Generation Report)	Frame GTs: FOM cost A$8 (=€5.50/kW); VOM cost A$12/kW Aero-derivative GTs: FOM cost A$10/kW (=€7/kW); VOM costs A$15/kW[43]	FOM costs estimated to be 40% of total operating and maintenance costs.
IPART (NSW, Australia)	GT FOM costs: A$13.9/kW (=€9.50/kW). GT VOM costs: A$11.0/kW[44]	FOM costs estimated to be 55% of total operating and maintenance costs.

6.3.30 Key points to note are:

[39] All exchange rate conversions based on exchange rates as of 07/10/2016
[40] Based on 5 Integrated Resource Plans from different players in WECC (incl. CEC), values in 2014US
[41] Values in 2013 US$, report was commissioned by CEC to provide a set of metrics (including levelised cost) to be used to make regulatory decisions
[42] Values based on US$2010
[43] all values in 2015 A$. Source: Annually produced report (for 2015, published 11/8/16) used for AEMO network development plan
[44] Values in A$ 2012/3

- All reported values for gas turbine FOM costs are substantially lower than €58.79/kW average for "other gas" generators reported in the SEM for 2014. FOM costs for gas turbines tend to range between about €10-25/kW for aero derivative gas turbines, and slightly lower for frame gas turbines.
- Reports differ widely in the proportion of Operating and Maintenance Costs that are deemed to be fixed and the proportion that are deemed to be variable.

6.3.31 We welcome consultation feedback on why reported SEM costs are higher than international benchmarks, and whether there is scope for generators to cut fixed operating costs going forward, or whether they are an unavoidable consequence of the age of SEM plant.

Summary and indicative numbers for the Existing Capacity Price Cap

6.3.32 **We are considering setting the Existing Capacity Price Cap at around 0.5 x Net CONE**. Based on the indicative estimates of Net CONE set out in Section 6.2, this would mean an Existing Capacity Price Cap of around €38.90/kW p.a.

6.3.33 The rationale for setting the Existing Capacity Price Cap at this level is that:

- If set at this level, we estimate that the almost all of plant required to meet the Capacity Requirement could bid at its NGFC without needing to apply for a unit specific bid limit.
- It is consistent with relevant international benchmarks.

6.3.34 Arguably there is scope to set a tighter limit, which would require generators to cut fixed operating costs below current levels. However, if the cap is set at a lower level, there is a risk that there will be a significant number of applications for a higher unit specific limit, many of which will have little bearing on the clearing price or pay-as-bid prices. This will impose significant administrative burden on both the industry and the RAs, at a time close to I-SEM go-live, when resources are likely to be stretched.

6.3.35 The SEM Committee hopes that competition from capacity providers will be deliver these benefits over time. However, given the tight timescale and the practical difficulties in establishing achievable fixed cost efficiency savings, the SEM Committee is not inclined to factor in significant potential savings into the Existing Capacity Price Cap for the first transitional auction. However, **where a generator bids for a higher unit specific cap, the SEM Committee does not preclude requiring the generator in question to bid at a level consistent with efficiency savings**.

6.4 DEMAND CURVE PARAMETERS

Background

6.4.1 In CRM Decision 1 (SEM-15-103), prior to the decision to adopt a sloping demand curve for the CRM auctions, the SEM Committee decide to retain the existing 8-hour Loss of Load Expectation (LOLE) standard that has been used to set the Annual Capacity Payment Sum in the SEM. The SEM Committee decided to make some refinements to the way in which the 8-hour LOLE calculation is calculated, notably:

- To define the capacity standard in terms of a de-rated MW Capacity Requirement, rather than on a nameplate basis;
- To adopt multiple scenarios to calculate the Capacity Requirement, and to base the Capacity Requirement on the "least regret cost scenario".

6.4.2 In CRM Decision 2, the SEM Committee confirmed its intention to base the quantity of Reliability Options auctioned in each of the four transitional years from 2017/18 to 2020/21 consistent with the 2020/21 Capacity Requirement.

6.4.3 In CRM Decision 3 (SEM-16-022), the SEM Committee stated that it is minded to use the following principles to set the slope and position of the demand curve:

- System security (Reliability) and economic efficiency:
  - Should be consistent with the security standard of maintaining the 8 hours per Capacity Year LOLE standard set out in CRM Decision 1;
  - Should, at minimum, reflect an economically efficient trade-off between price of Reliability Option and value of extra reliability[45], but could be less vertical as a result of other factors set out below;
- Competition: Should reduce susceptibility of the auction to market power (in conjunction with other market power controls);
- Stability (price volatility):
  - Should reduce price volatility impact from small variations in market conditions and administrative parameters, including lumpy investment decisions, and demand forecast changes; and
  - Should limit the frequency of outcomes at the Auction Price Cap.
- Practicality: Should perform well under a range of market conditions, including changes in administrative parameters and administrative estimation errors.

Key considerations in setting the all-island demand curve parameters

De-rating and Capacity Requirement

6.4.4 Consistent with the above principles and decisions, as illustrated in Figure 10 below, for the first transitional auction (in respect of Capacity Year 2017/18) the SEM Committee, is considering:

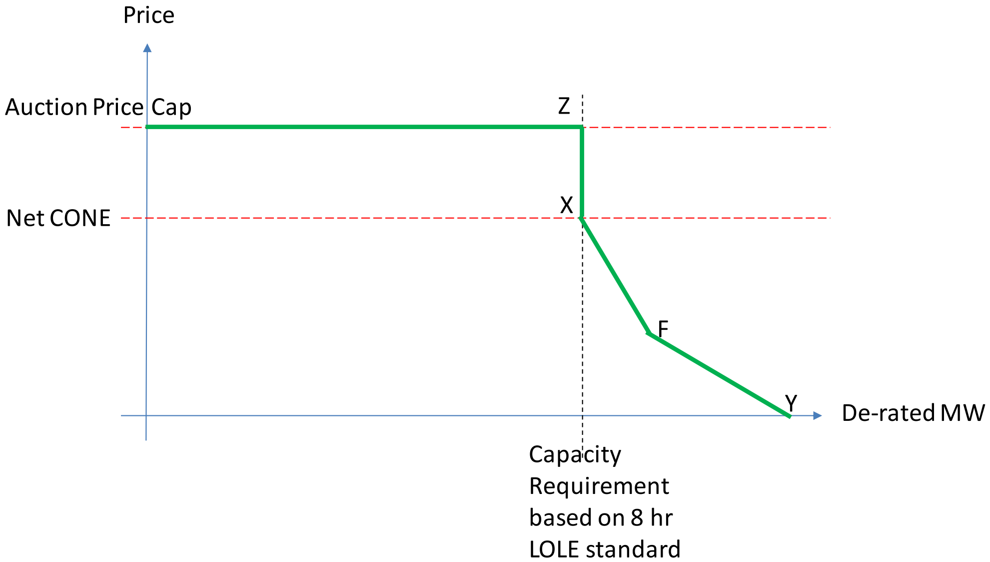
- Setting the demand curve for the first transitional auction horizontal at the Auction Price Cap between 0MW and the 2020/21 Capacity Requirement as estimated prior to the first transitional auction; and
- Making the demand curve pass through point X where the price = Net CONE and quantity equals the Capacity Requirement, analogous to the price and volume[46] which determine the Annual Capacity Payment sum in the SEM CPM.

[45] Value of Lost Load x reduction in unserved energy

- Making the demand curve vertical between the Auction Price Cap and Net CONE, at a level of MW consistent with the Capacity Requirement. The capacity requirement based on a “minimum” 8-hour standard which aligns with the view that the 8-hour standard is the minimum acceptable level of system security[47].

6.4.5 The SEM Committee is currently consulting on the De-rating and Capacity Requirement methodology and may make some changes to the TSO’s proposal set out in SEM-16-051a, which resulted in an indicative de-rated Capacity Requirement of 7,498MW for 2020. However, 7,498MW of de-rated capacity is the best current estimate of the 2020/21 Capacity Requirement. These values are prior to any adjustments made to the demand curve after the Qualification window, to reflect any information obtained during the Qualification Window from optional bidders.

Figure 10: Potential transitional auction demand curve



6.4.6 If the Auction Price Cap is set at 1.5 x Net CONE, in theory, this could lead to payments to capacity providers in 2017/18 which are 1.5 times higher than they would be under the SEM CPM (if the auction clears at point Z). However, given the current excess of existing capacity over the Capacity Requirement and the suite of market power controls, we would expect the auction to clear below Net CONE.

6.4.7 We note that the proposals to make the transitional auction demand curve pass through the Capacity Requirement at Net CONE (point X), and be vertical at the Capacity Requirement differs from the curve positioning employed in US auctions (see Figure 11), where generally the demand curve:

- Is shifted up and to the right of point X. Historically, the US PJM market placed Net Cone at 101% above the target capacity level. Recently, PJM has moved to a more

[46] SEM volume is specified in nameplate MW (with an equivalent capacity credit for wind), not de-rated MW, and prices are per unit of nameplate capacity, not de-rated capacity

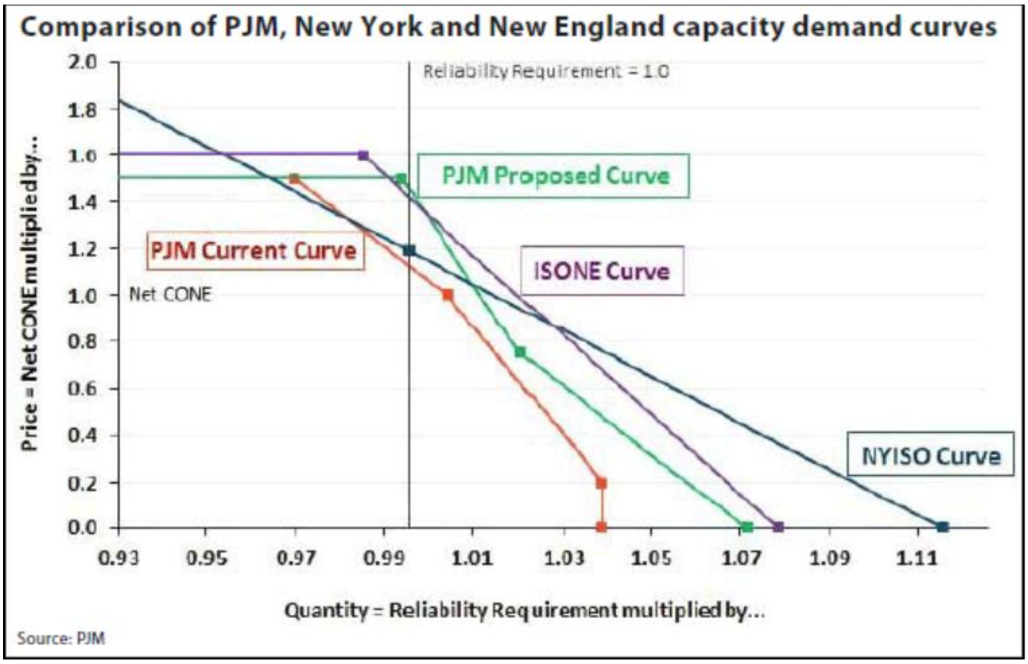
[47] If less than the Capacity Requirement is bid at the Auction Price Cap, in theory, the auction could end up with less than the “minimum” standard.

conservative Demand Curve where Net Cone is at around 102 % to 103% of the target capacity level, while both NYISO and ISO-New England place Net Cone between 103% and 104%. Since the curve is steeply sloped this means that at the target capacity, ISO-NE and NYISO are prepared to pay a price of about 120% of Net CONE.

- Is sloped rather than vertical between X and Z, with US ISO generally prepared to pay for less capacity (and sacrifice system security) once the price rises above Net CONE, indicating that they are more prepared to accept an outcome with less than the target capacity.

6.4.8 We note that by basing the 2017/18 demand curve on the 2020/21 Capacity Requirement, we have effectively shifted the demand curve for 2017/18 to the right.

Figure 11: Key US capacity auction demand curves



6.4.9 We note that ISO-NE and PJM derive their curve positioning through simulations of market entry in response to the Demand Curve. By modeling the entire curve and assuming over time shocks and factors which will lead to excess, they model the ability of the curve to attract entry while generally meeting the target standard and have a suitably low probability of falling below a minimum standard[48]. Such an approach is modeling intensive, and is not necessarily relevant to the situation of the transitional auctions, nor practical for the first transitional auction in which little new entry is anticipated.

6.4.10 The SEM Committee may re-visit the slope and placement of the curve between X and Z in subsequent T-4 auctions, where material amounts of new entry at prices around Net CONE is more likely, and may, at that time follow US practice in shifting the curve up and to the right of X.

[48] As with any modeling of this type, assumptions as to entrant behavior are important and the results are not precise. The modeling does, however, consider the value of the Demand Curve at Net Cone as well as the shape and slope of the curve

6.4.11 For the transitional auctions, particularly the first transitional auction, when we know there is significant installed capacity in excess of the Capacity Requirement, greater focus should be on the slope and shape of the curve at volumes in excess of the Capacity Requirement. As illustrated in Figure 10, key parameters which determine the shape and positioning of the curve are:

- The **zero-crossing point**, that is the level of excess capacity at which the auction should be able to clear at a zero price (point Y in Figure 10)
- Whether there is another **inflection point** (drawn as point F in Figure 10) at which the curve changes slope.

6.4.12 We discuss the application of the principles determined in CRM Decision 3 to this portion of the curve below.

Economic efficiency

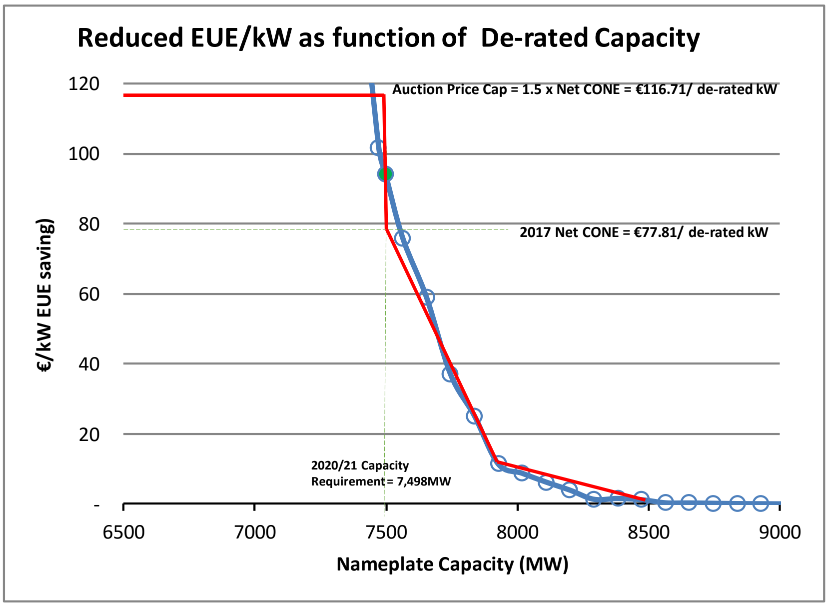
6.4.13 We have asked the TSOs to estimate the relationship between installed capacity, and number of hours of LOLE, the Expected Unserved Energy (EUE) in MWh, and the cost of EUE to the consumer in €m p.a. when unserved energy is valued at VoLL. They have produced estimates of this relationship over a broad range of installed capacities, based on the all-island demand forecast for 2020/21- the year which will determine the demand curve for the transitional auction for the 2017/18 Capacity Year. To some extent, the relationship depends on the mix of plant, including the unit sizes and outage rates, and the analysis is based on the current plant mix.

6.4.14 Clearly, the greater the installed capacity (for a given demand scenario), the lower the number of hours of LOLE, the MWh of unserved energy and the loss to the consumer from that unserved energy. If capacity is cheaper than Net CONE at the Capacity Requirement it is economically efficient for consumers to pay for more capacity than the Capacity Requirement to reduce unserved energy, since the incremental cost to the consumer of paying for more capacity is less than the saved opportunity cost of lost load.

6.4.15 The TSOs modelling include the proposed inclusion of reserve within the Capacity Requirement in line with their Derating and Capacity requirement proposals. The way they have modelled it, an incident of “lost load” is deemed to have occurred when available capacity falls below the level required to serve demand and meet the reserve requirement. They have then valued a MW of reserve shortfall that last for 1 hour at the same value (VoLL) as a MWh of lost load. Their estimate of the cost to the consumer are therefore an over-estimate, since not all instances of a shortfall in reserve below the target requirement will result in lost load.

6.4.16 Nevertheless, we have used the TSOs’ estimates to estimate the relationship between the amount of de-rated capacity on the system in de-rated MWs, and the incremental saving in reduced EUE to the consumer from an additional kW of de-rated capacity being on the system. This relationship is depicted by the blue line in Figure 12 below.

Figure 12: Relationship between increased de-rated capacity and saving in value of Expected Unserved Energy (EUE)



6.4.17 Figure 12 illustrates that at the 2020/21 Capacity Requirement of 7,498 de-rated MW, the incremental saving to the customer in terms of lost load of installing another kW of de-rated capacity is €94/kW p.a., a little more than Net CONE. If the amount of de-rated capacity on the system rises to 8,000MW, the incremental saving to the consumer falls to around €10/kW p.a., and by the time the installed de-rated capacity is as high as 8,500MW, the incremental value of additional capacity to the consumer is less than €1/kW p.a.

6.4.18 This analysis gives one view of the efficient trade-off between extra capacity and what consumers should be prepared to pay for it, i.e. the demand curve. The red line shows a demand curve which would broadly reflect this trade-off, with a point of inflexion low down the curve, and a zero-crossing point at around 8,500MW of de-rated capacity, only 13% in excess of the Capacity Requirement.

6.4.19 However, whilst the analysis provides *a* view, it is incomplete and subject to modelling uncertainty in a number of respects:

- It does not take into account the full effect of more installed capacity on the energy market prices and the benefit to the consumer if greater RO volumes leads to lower plant exit (or more plant entry) and this has a constraining effect on energy market prices. To model the size of this effect, we would need to make some assumptions about which plant win the auction, and which plant exit as a result (notwithstanding the current Grid Code requirement to give 3 years' notice). However, to the extent that greater RO volumes serve to restrain energy prices, this would argue in favour of a shallower slope to the curve and a larger zero-crossing point;
- It ignores competition effects. As discussed further below, a shallower sloped demand curve and greater zero crossing point can both substitute for competition between potential capacity providers in the current auction, and result in greater competition in subsequent years;

- It ignores the value of reduced volatility in capacity prices within years which can result from a shallower sloped demand curve and greater zero-crossing point.

Competition considerations

6.4.20 There may be two competition reasons to implement a less vertical and more gently sloping demand curve, than one which describes the "efficient" trade-off described above:

- **Within year competition effects**. As we noted in CRM Consultation 3, with a sloping demand curve, the bidder faces "competition" from reduced demand for capacity as well as from other generators. The greater the price elasticity of demand (sensitivity of demand to price offered), the more "competition" the bidder faces from reduced demand, and the more its ability to exercise market power may be constrained;
- **Multi-year effects**. If the demand curve is less vertical, and more gently sloped, this can lead to a higher volume of ROs being awarded in Capacity Year T, if prices bid are low. This can increase the level of competition for ROs in Capacity Year T+1, T+2 etc, and lower prices to consumers if less plant exits the market in Capacity Year T as a result. In principle, the reduction in consumer bills in subsequent years could outweigh the impact of higher consumer bills in Capacity Year T. We note that by using the demand forecast for 2020/21 to set the Capacity Requirement for 2017/18, we are already effectively employing this approach to a degree.

Reducing volatility

6.4.21 As we noted in CRM Consultation 3, an additional benefit of a sloping demand curve is that it can be expected to smooth out the volatility in auction prices from year to year as supply and demand conditions change, particularly where the scale of entry is large relative to market size (i.e. the 'lumpiness problem') as will be the case for the I-SEM. The more gently sloped the curved, the greater the potential smoothing effect. Generally, the less volatile the price, the lower the risk and cost of capital is for investors, ultimately reducing the long run cost of capacity to consumers.

6.4.22 As discussed below, in ISO New England and PJM, significant work goes into modelling the impact of the demand curve slope and positioning.

International experience

6.4.23 We note that the zero-crossing point in smaller markets tends to be a higher percentage of the target capacity than in larger markets.

6.4.24 As illustrated in Figure 11, in approximate terms, the demand curve for:

- The New York ISO area as a whole has a zero-crossing point about 12% (4800 MW) above the target capacity level. However, for smaller New York zones (such as New York City itself), which are still larger than the I-SEM in peak demand, the target is 15% or 18% above the zonal Capacity Requirement;
- ISO-NE is 8% (2800 MW) above the target capacity level;
- PJM recently moved to 7% (from about 3.5%), approximately 12,000 MW in the large PJM market.

6.4.25 We note that more mature capacity markets such as ISO New England and PJM[49], commission very detailed modelling exercises to model the impact of differently sloped demand curves on new entry, and how differently shaped curves result in different price and volume outcomes over time, and impact security of supply and price volatility. These markets are multiple times larger than the I-SEM (so are better resourced) and are more mature, so are better able to calibrate their models with historical data. At this juncture it will not be practical for the RAs to undertake the detailed modelling of the demand curve that these US markets have completed. However, we will reflect international experience in the shaping of the demand curve, and given the small size of the all-island market, with limited interconnection, it would appear that a zero-crossing point in the region of 15-20% in excess of the Capacity Requirement may appear appropriate.

Options and indicative demand curves values for first transitional auction

6.4.26 We have set out three options below for the form of the demand curve. These options are based around the Capacity Requirement estimated by the TSOs in their paper on the Methodology for the Calculation of the Capacity Requirement and De-rating Factors (SEM-16-051a), and will need to be re-calibrated for changes in the Capacity Requirement and Net CONE due to any changes in methodology or re-forecasting between now and the auction. Note that as set out in SEM-15-103, these curves will also be adjusted for any discretionary auction bidders who indicate during the Qualification process that they will not participate.

6.4.27 These options are set out for illustrative purposes in Figure 13, which also demonstrates the trade-off between increased capacity and the saving in the cost of EUE/kW, which was illustrated in Figure 12 (blue line). We may choose to employ hybrid / intermediate options.

Figure 13: Demand curve options under consideration

[49] See for instance, 2014 PJM Variable Resource Requirement Parameter Review conducted by Brattle or testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO NEW ENGLAND INC. regarding a forward capacity market demand curve

6.4.28 As illustrated in Figure 13, all three options have a demand curve which is horizontal at the Auction Price Cap (illustratively set at 1.5 x Net CONE) up to the Capacity Requirement, and are vertical at the Capacity Requirement between the Auction Price Cap and Net CONE. The options differ below a price of Net CONE:

- Option A: The curve has a flat slope, without inflection from Net CONE to a zero-crossing point at 20% in excess of the Capacity Requirement;
- Option B: The curve has a flat slope, without inflection from Net CONE to a zero-crossing point at 10% in excess of the Capacity Requirement;
- Option C: The curve has a point of inflection at price = €50/kW, and demand = 7,700MW of de-rated capacity. After the point of inflection, the curve slopes more gently down to a zero-crossing point at 20% in excess of the Capacity Requirement. The point of inflection has been set at a point on the EUE saving /kW curve from (as depicted in Figure 12) about 25% above the indicative Existing Capacity Price Cap (ECPC) as set out in section 6.3.

6.4.29 In Section 6.3 we explained that our estimate of the Existing Capacity Price Cap is pitched at a level which will cover the existing capacity required to meet the Capacity Requirement to cover its NGFC. Option C has been designed to have a relative flat slope at this point, and at a price up to 25% above the Existing Capacity Price Cap. There are competition advantages in having a flatter demand curve in this region, and having a steeper demand curve in the region where the market is unlikely to clear. If the demand curve is flat throughout, this could necessitate a high zero-crossing point, and result in consumers paying for capacity which does not provide them with longer run benefits. We also recognise that competitive pressure (given the surplus of capacity over the Capacity Requirement) may lead bidders to bid below their 2017/18 NGFCs in the first transitional auction, if they wish to remain operational to avail themselves of higher expected revenues in subsequent years as the capacity margin tightens and/or energy market margins increase.

6.4.30 Option C, with its point of inflection and an initially steep curve, which flattens out in the region where the unconstrained all-island auction is likely to clear may be better at promoting competition objectives, and at least in the short term, may reduce price volatility. Clearly this will not necessarily be the case in subsequent auctions, as and when the balance between existing capacity and the Capacity Requirement changes. Any decision with regard to the first transitional auction should in no way be construed as setting a precedent for subsequent auctions.

6.5 LOCATIONAL PARAMETERS

6.5.1 As set out in the Local Security of Supply consultation (SEM-16-052), we may consider implementing a nested approach to managing constraints. For instance, whilst the constraints are yet to be defined, in SEM-16-052, we used the example of there being a local requirement for Northern Ireland and for the Dublin area.

6.5.2 We set out three options for the form of the constraint specification, namely:

- Option 1: A separate capacity requirement for each constrained capacity area, measured in MW
- Option 2: A separate capacity requirement for each constrained capacity area, measured in units (albeit the overall target for the whole market would still be measured in MW).
- Option 3: Nested capacity areas (with capacity requirements specified in MW).

6.5.3 In each case, there is clearly, at minimum, a requirement to define a locational parameter (local capacity requirement in minimum number of MW, or number of units).

6.5.4 In options 1 and 3, in principle it is possible to specify a sloped local demand curve, as well as a sloped all-island demand curve. This is common practice in zonal US capacity markets, but in these markets prices are zonal too.

6.5.5 The SEM Committee has not yet decided how to proceed with regard to Local Security of Supply- whether locational requirement should be incorporated within the I-SEM CRM, and if so, which of options 1 to 3 will be used to define location constraints. However, if the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, it does not propose at this stage to include the additional complexity of defining local demand curves.

6.5.6 In principle, a zonal sloping demand curve can have advantages if prices bid in the under-supplied zone are not as high as expected, in that additional capacity is procured, and the chance that the zone is under-supplied in subsequent auctions is reduced. However, this effect can also be achieved, at least in part, by the nesting approach in which bids not selected within a constrained zone are added back into the all-island supply curve once along with other plant outside the nested (constrained) zones once the minimum requirements have been satisfied.

6.5.7 Key issues associated with implementing with zonal demand curves in the first transitional auction are:

- Impact on consumer bills- it could result in higher consumer bills if more than the minimum required capacity is awarded an out-of-merit RO on a pay-as-bid basis to manage what may be transitory constraints (when constraints are represented in T-4 auctions, there is an implicit assumption that the constraint is likely to last more than 4 years);
- It would have no impact on the volatility of zonal clearing prices, unlike in zonally priced auctions, since all in-merit plant will be paid market wide clearing price; and
- It adds complexity, at least in terms of the need to determine additional slopes and zonal zero-crossing points.

6.6 SUMMARY OF QUESTIONS

Net CONE

6.6.1 Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10 If not, explain why.

Auction Price Cap

6.6.2 Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?

Existing Capacity Price Cap

6.6.3 Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs (NGFC) at:

Max[(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

6.6.4 Do you agree with the proposed process and data inputs to calculate NGFCs as set out in 6.3

6.6.5 Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.

6.6.6 Do you think that the NOFC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or do you think that the NFOC contain material variable cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap?

6.6.7 Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.

Demand curve parameters

6.6.8 Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?

6.6.9 Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?

Locational parameters

6.6.10 If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?

7. LOAD FOLLOWING FOR SECONDARY TRADING

7.1 INTRODUCTION

7.1.1 In CRM Decision 1, the SEM Committee decided that Reliability Options will be "load-following". The volume on which a capacity provider with 1MW of Reliability Option will be required to make difference payments on will be scaled back, where a scarcity event happens at times when load is less than the volume of Reliability Options.

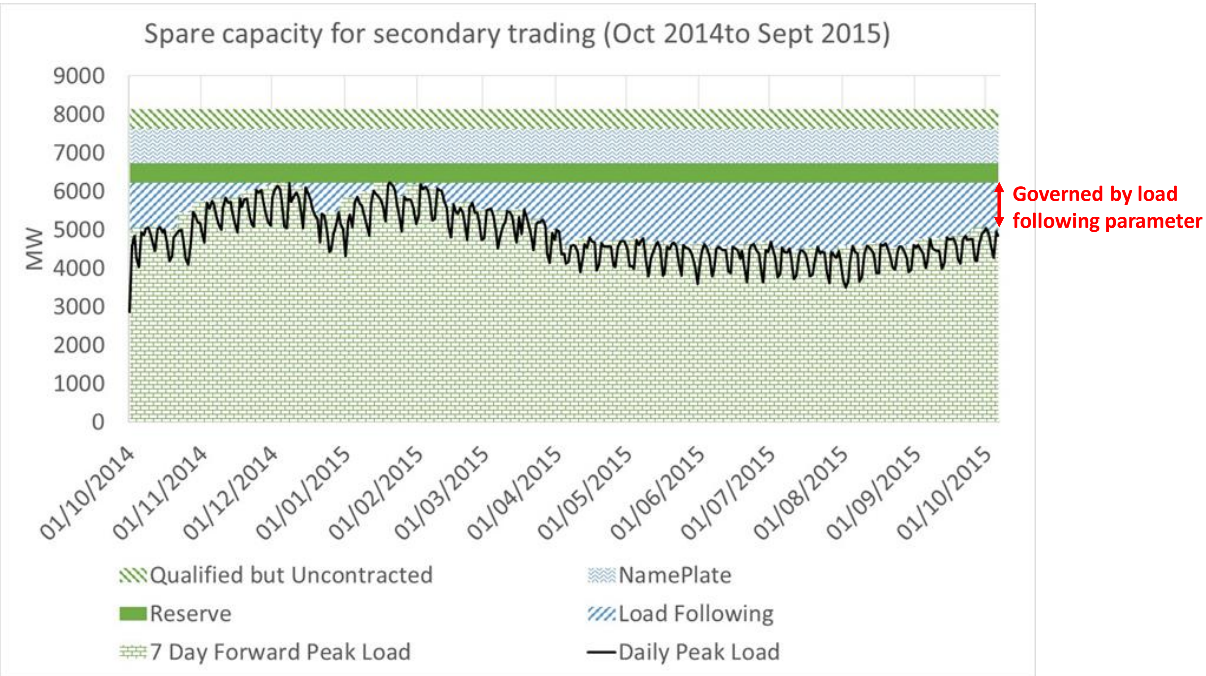
7.1.2 The decision to make the Reliability Option load-following has implications for secondary trading.

7.1.3 In CRM Decision 2 (SEM-16-022), the SEM Committee confirmed that plant should be able to physically back secondary trades using:

- Capacity that did not win a Reliability option in the primary auction;
- The margin between "de-rated" and "nameplate" capacity for plant that are allocated reliability options (albeit each plant can only buy this capacity up to 10 weeks per year); and
- Margin between de-rated capacity and load following obligation: Capacity that lies between its adjusted load-following capacity obligation and de-rated capacity. This capacity for each Capacity Market Unit, b, which can be made available, will be determined on the basis of a profiling factor for the load-following capacity obligation parameter, now known as the Product Forecast Capacity Quantity Scaling Factor (FPFCQSF) in the drafts of the TSC and CMC.

7.1.4 These three sources of "headroom" are illustrated in Figure 14 below.

Figure 14: Headroom for secondary trading and load following parameter



7.1.5 The key difficulty with setting FPFCQSF is that the load-following factor which will be applied to Reliability Options will only be known in real time, when actual demand is known, whereas the Load Adjustment Factor for the purposes of secondary trading must be published ahead of delivery, since it governs secondary trading in advance of delivery. Therefore, a methodology must be specified for setting the ex-ante factor. SEM-16-022 stated that a methodology will be developed to determine the level of load following that can be prudently assumed at the time of secondary trading as part of the parameters consultation

7.1.6 The methodology should seek to balance:

- Prudence that there is sufficient physical capacity available to back the Reliability Option, if for instance, demand outturns higher than forecast. Prudence will support system security objectives, and serve to ensure that Suppliers are protected - there is less risk that a capacity provider could over-contract and face financial difficulties in meeting its difference payment obligations; and
- Enhancing liquidity and competition in the secondary market, and hence enhancing the ability of capacity providers to manage their Reliability Option outage risk and reduce their costs of capital.

7.1.7 Key questions in setting the load following parameter, which are not necessarily independent are:

- Granularity of FPFCQSF. Clearly, the level of demand (and hence load following) varies seasonally and by time of day, and is higher on weekdays than weekdays, so a key question is how granular should the parameter be. Clearly some granularity is needed, since at key times of year, by definition, there is not expected to be much if any headroom between peak demand and demand in that hour. However, it may be impractical to set load following factors ex ante for each half hour in the year, and monitor compliance against this factor for each Capacity Market Unit in secondary trading activity.
- Methodology and governance:
  - Include forecast element? Should the load following parameter reflect only historical load profiles for seasonality, time of day, weekday/weekend, or should they incorporate any element of weather forecasting?
  - How far ex-ante should the load-following parameter be set?
  - How should setting the load following parameter be governed? One option, which is more practical, if the parameters are set ex ante in for the whole Capacity Year in advance, is that these parameters could be approved by the SEM Committee. However, if parameter values incorporate an element of demand forecast, so are more dynamic, a more practical option is that the methodology is approved by the SEM committee, but values are regularly recalculated and updates published by the TSOs (either in their capacity as the CRM Delivery Body or as the SEMO).

7.1.8 A more granular and dynamic approach to setting the parameter, could clear result in the release of more capacity for secondary trading. However, analysis by the RAs presented in CRM Decision 2 (refer to SEM-16-022 for assumptions) indicated that there should be sufficient spare capacity to provide cover in the secondary market to cover planned outage (a key objective) and a degree of cover for forced outages, and that it may not be necessary to implement a very granular and dynamic set of parameters in order to provide sufficient headroom for trading in the secondary market.

7.1.9 We consider that the load following parameters be set ex ante for the whole Capacity Year, based upon historical ratios of demand in the relevant period to peak demand for that Capacity Year. A five-year historical averaging period would probably be sufficient, as any longer look back periods may capture times when the structure of economy and hence demand profiles were materially different, whereas as a five year look back period allows the parameters to adapt relatively quickly to economic development (e.g. the growth of data centres which could materially affect time of day/year demand patterns). However, we may want to incorporate a “safety” margin, rather than using the average headroom.

7.1.10 The granularity of these factors would be:

- Monthly. Load patterns vary significantly within quarters, e.g. October weather patterns are substantially different from December ones, so we consider that quarterly
- Time of day: Broadly consistent with the trading periods in the energy market (Peak hours, Mid-merit 1 non peak hours, other hours)[50] to allow for more consistent management of positions across Reliability Options and energy hedging instruments, and would be monthly granularity.

7.1.11 The resulting structure of the load following parameter would therefore be in line with that set out in the following Table.

Figure 15: proposed granularity of ex-ante load following parameter

	Peak hours (currently 17:00 to 21:00) in winter	Mid-merit but non-peak hours (currently 07:00 to 17:00 and 21:00 to 23:00 on Business Days)	Other hours
January			
February			
March			
April	n.a.		
May	n.a.		
June	n.a.		
July	n.a.		
August	n.a.		
September	n.a.		
October			
November			

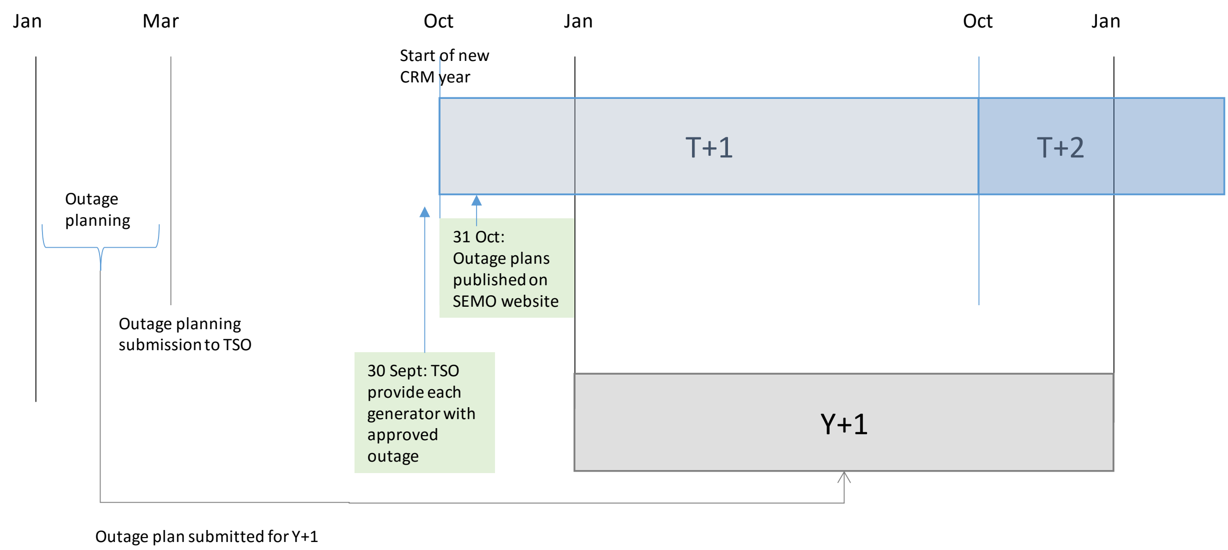
[50] Peak hours and currently defined as Trading Periods arising during the hours beginning at 17:00 and ending at 21:00 on all days during, October, November, December, January, February and March. Mid-merit 1, i.e. Directed Contract mid-merit products, apply at the full rate for Trading Periods at the Contract Quantity during the hours beginning at 07:00 and ending at 23:00 on Business Days, and at 80% for days that are not Business Days. However, this application cannot logically apply to the load following factor, and we would propose to apply it only to Business Days

December			

7.1.12 We would propose that these parameters be estimated by the TSOs, for approval by the SEM Committee consistent with the outage planning process, since a key reason to allow secondary trading backed by the headroom between load following and peak demand is to support outage risk management. The current outage planning process is prescribed within OC2 of the Grid Code, and works on a Calendar Year basis, rather than a Capacity Year.

7.1.13 As illustrated in Figure 16, under OC2, the TSOs provide generators with an approved outage plan for calendar year Y+1 by the end of September in the previous year[51], and it reasonable to assume that prudent generators will want to manage their outages in the secondary market as soon as they know the approved outage plan. This would mean that the SEM Committee approved load following parameters for the complete calendar year Y+1 would ideally be published by the end of September.

Figure 16: Current outage planning process and new Capacity Year



7.1.14 There is a question of whether capacity provider should be able to use any headroom against load following for calendar year Y+2, and if so whether the load following parameters which apply for calendar year +1 should also apply to calendar year + 2 (and possibly subsequent years too). Alternatively, it would be possible to "release" only a prudent percentage of the Y+1 load following margin for secondary trading in Y+2 and subsequent years, e.g. 75% in case the load following parameter matrix is subsequently adjusted the following year. We seek feedback on this point.

[51] Although the complete plan is not published on the SEMO website until the end of October

7.2 SUMMARY OF QUESTIONS

7.2.1 Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?

7.2.2 Do you think that capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage?

8. NEXT STEPS

8.1.1 Interested parties are invited to respond to the consultation, presenting views on the options set out in this paper and where applicable any minded to positions that have been expressed proposals and discussion in this paper.

8.1.2 The SEM Committee intends to make a decision in Q1 2017 on the parameters for the first transitional auction covered in this consultation paper. In reaching this decision we will take into account comments received from respondents to this paper as well as feedback obtained at any subsequent public workshops.

8.1.3 Responses to the consultation paper should be sent to Mary O'Kane (mary.okane@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on 21 December 2016 .

8.1.4 Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.

9. ACRONYMS

ACER	Agency for the Co-operation of Energy Regulators
ACPS	Annual Capacity Payment Sum
AER	Alternative Energy Requirement
ALFCO	Adjusted Load Following Capacity Obligation
BCoP	Bidding Code of Practice
BM	Balancing Market
BNE	Best New Entrant
CACM	Capacity Allocation and Congestion Management
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
CMU	Capacity Market Unit
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DCENR	Department of Communications, Energy and Natural Resources
DECC	Department of Energy and Climate Change
DSR	Demand Side Response
DSU	Demand Side Unit
EC	European Commission
EEAG	The Environmental and Energy State Aid Guidelines
ENTSO-E	European Network of Transmission System Operators – Electricity
ETA	Energy Trading Arrangements
EU	European Union
FiT	Feed in Tariff
FOR	Forced Outage Rate
FTR	Financial Transmission Right
GB	Great Britain
GB CM	Great Britain Capacity Market
GDP	Gross Domestic Product
GTUoS	Generator Transmission Use of System
GUA	Generating Unit Agreement
HLD	High Level Design
ICE	Intercontinental Exchange
IDM	Intra-Day Market
IED	Industrial Emissions Directive
I-SEM	Integrated Single Electricity Market
ISO NE	Independent System Operator New England
LoLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MB	Balancing Market (Italy)
MGP	Day Ahead Market (Italy)
MRP	Market Reference Price
MSD	Ancillary Services Market (Italy)
MW	Megawatt

MWh	Megawatt hour
NG	National Grid
OCGT	Open Cycle Gas Turbine
ODR	Over Delivery Rate
PER	Peak Energy Rents
PFP	Pay-for-Performance
PJM	Pennsylvania Jersey Maryland
PPA	Power Purchase Agreement
PPB	Power Procurement Business
PSO	Public Service Obligation
ROC	Renewables Obligation Certificate
RP	Reference Price
SEM	Single Electricity Market
SO	System Operator
SoLR	Supplier of Last Resort
SP	Strike Price
SRMC	Short Run Marginal Cost
TLAF	Transmission Loss Adjustment Factor
TSC	Trading and Settlement Code
TSO	Transmission System Operator
US	United States
VoLL	Value of Lost Load

APPENDIX A HISTORICAL LOLP VALUES

Figure 17 sets out the average historical LOLP values by quarter and by half-hour of the day. They show the evolution of time-of-day/seasonal LoLP patterns over the history of the SEM, in the form of heat map. The numbers in Figure 17 are expressed in standard form, i.e. the value in 2007 Q4 for 00:00 to 00:30 of 8E-06 denotes 8×10^{-6} = 0.000008 = 0.0008%, i.e. a very low loss of load probability.

The value for 2013 to the present are summarised in Figure 5 in Section 3.1.2.

Figure 17: Historical LOLP heat map by quarter and half-hour

Note:

Average of LOLP	00:00	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	11:30	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30
2007																																																
Qtr4	8E-06	4E-06	2E-06	8E-07	8E-07	1E-06	1E-06	5E-07	6E-07	5E-07	6E-07	7E-07	4E-06	8E-06	9E-05	4E-04	0.001	0.002	0.003	0.005	0.005	0.006	0.005	0.005	0.005	0.004	0.003	0.002	0.002	0.002	0.003	0.003	0.005	0.023	0.059	0.076	0.054	0.034	0.027	0.017	0.01	0.007	0.003	0.001	3E-04	1E-04	5E-05	2E-05
2008																																																
Qtr1	6E-06	5E-06	2E-06	1E-06	7E-07	6E-07	6E-07	5E-07	5E-07	4E-07	2E-06	5E-07	4E-06	9E-06	4E-05	5E-04	0.002	0.001	0.002	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.001	7E-04	9E-04	1E-03	0.001	0.001	0.001	0.004	0.014	0.023	0.019	0.013	0.014	0.01	0.006	0.003	0.001	5E-04	1E-04	3E-05	4E-05	1E-05
Qtr2	1E-04	8E-05	6E-05	3E-05	2E-05	2E-05	2E-05	2E-05	1E-05	1E-05	9E-06	9E-06	4E-05	9E-05	3E-04	0.002	0.007	0.01	0.015	0.017	0.016	0.017	0.019	0.02	0.021	0.019	0.013	0.009	0.01	0.01	0.009	0.009	0.009	0.012	0.013	0.012	0.008	0.006	0.004	0.002	0.002	0.003	0.003	0.002	0.002	8E-04	2E-04	8E-05
Qtr3	2E-05	1E-05	4E-06	2E-06	2E-06	9E-07	8E-07	1E-06	1E-06	1E-06	3E-06	2E-06	8E-06	2E-05	1E-04	5E-04	0.002	0.002	0.005	0.007	0.008	0.009	0.009	0.009	0.01	0.01	0.007	0.005	0.006	0.005	0.004	0.004	0.004	0.006	0.008	0.008	0.005	0.004	0.003	0.003	0.006	0.005	0.003	0.001	6E-04	2E-04	6E-05	3E-05
Qtr4	1E-05	8E-06	7E-06	3E-06	3E-06	2E-06	1E-06	2E-06	1E-06	1E-06	2E-06	2E-06	4E-06	2E-05	9E-05	6E-04	0.003	0.003	0.005	0.007	0.007	0.007	0.007	0.008	0.01	0.011	0.006	0.005	0.005	0.005	0.006	0.007	0.008	0.024	0.048	0.055	0.041	0.032	0.027	0.017	0.009	0.006	0.003	0.002	4E-04	9E-05	5E-05	1E-05
2009																																																
Qtr1	1E-06	7E-07	2E-07	3E-07	9E-08	5E-08	6E-08	4E-08	4E-08	2E-08	2E-08	2E-08	5E-08	1E-07	1E-06	5E-06	2E-05	3E-05	9E-05	1E-04	1E-04	2E-04	2E-04	2E-04	2E-04	2E-04	1E-04	1E-04	1E-04	2E-04	2E-04	2E-04	3E-04	0.001	0.005	0.009	0.007	0.004	0.003	0.002	8E-04	3E-04	1E-04	3E-05	2E-05	6E-06	8E-06	3E-06
Qtr2	3E-08	5E-08	5E-08	3E-08	1E-08	5E-09	3E-09	3E-09	2E-09	3E-09	5E-09	9E-09	3E-08	7E-08	1E-06	2E-06	9E-06	1E-05	2E-05	3E-05	3E-05	3E-05	3E-05	4E-05	4E-05	5E-05	3E-05	2E-05	2E-05	2E-05	2E-05	2E-05	2E-05	3E-05	5E-05	4E-05	2E-05	1E-05	2E-05	9E-06	6E-06	8E-06	2E-05	1E-05	5E-06	1E-06	4E-07	9E-08
Qtr3	7E-07	3E-07	8E-08	1E-08	6E-09	5E-09	3E-09	2E-09	3E-09	1E-08	1E-08	1E-08	2E-08	5E-08	3E-07	2E-06	4E-05	7E-05	2E-04	2E-04	8E-05	9E-05	1E-04	9E-05	1E-04	1E-04	8E-05	6E-05	5E-05	6E-05	5E-05	6E-05	8E-05	1E-04	2E-04	1E-04	8E-05	4E-05	3E-05	3E-05	8E-05	1E-04	8E-05	3E-05	6E-06	2E-06	1E-06	4E-07
Qtr4	1E-09	8E-10	3E-10	2E-10	2E-10	8E-11	2E-11	2E-11	2E-11	2E-11	6E-11	9E-11	1E-10	6E-10	4E-09	5E-08	4E-07	5E-07	1E-06	1E-06	1E-06	1E-06	1E-06	1E-06	2E-06	1E-06	7E-07	5E-07	5E-07	4E-07	6E-07	8E-07	5E-06	2E-04	5E-04	5E-04	1E-04	5E-05	3E-05	2E-05	7E-06	3E-06	1E-06	3E-07	4E-08	9E-09	2E-08	4E-09
2010																																																
Qtr1	7E-08	6E-08	8E-08	3E-08	2E-08	9E-09	6E-09	5E-09	2E-09	3E-09	2E-09	4E-09	1E-08	3E-08	1E-07	6E-07	2E-06	2E-06	5E-06	9E-06	1E-05	2E-05	3E-05	4E-05	5E-05	5E-05	5E-05	2E-05	2E-05	2E-05	3E-05	4E-05	1E-05	7E-05	6E-04	0.001	9E-04	4E-04	2E-04	8E-05	3E-05	1E-05	5E-06	1E-06	4E-07	3E-07	7E-07	3E-07
Qtr2	6E-09	1E-09	3E-10	2E-10	8E-11	6E-11	3E-11	2E-11	2E-11	3E-11	3E-11	2E-11	2E-10	1E-09	2E-08	3E-07	2E-06	4E-06	3E-06	5E-06	5E-06	6E-06	4E-06	5E-06	8E-06	8E-06	5E-06	2E-06	2E-06	2E-06	2E-06	3E-06	2E-06	3E-06	3E-06	2E-06	2E-06	1E-06	5E-07	3E-07	2E-07	4E-07	6E-07	9E-07	5E-07	1E-07	4E-08	4E-09
Qtr3	4E-09	6E-10	3E-10	8E-11	7E-11	4E-11	4E-11	3E-11	4E-11	5E-11	6E-11	1E-10	6E-10	4E-09	1E-07	7E-07	4E-06	1E-05	2E-05	3E-05	3E-05	3E-05	4E-05	4E-05	7E-05	1E-04	9E-05	5E-05	2E-05	2E-05	2E-05	2E-05	2E-05	5E-05	1E-04	1E-04	9E-05	7E-05	3E-05	1E-05	1E-05	3E-05	2E-05	8E-06	2E-06	5E-07	2E-07	5E-08
Qtr4	9E-08	4E-08	4E-08	3E-08	2E-08	1E-08	8E-10	6E-10	4E-10	3E-10	3E-10	4E-10	2E-09	2E-08	6E-07	9E-06	2E-05	4E-05	7E-05	9E-05	3E-05	5E-05	5E-05	2E-04	2E-04	2E-04	1E-04	8E-05	7E-05	7E-05	5E-05	7E-05	1E-04	8E-04	0.003	0.003	0.002	0.001	8E-04	5E-04	3E-04	8E-05	3E-05	7E-06	1E-06	5E-07	9E-07	6E-07
2011																																																
Qtr1	5E-11	5E-11	2E-11	5E-12	1E-12	9E-14	3E-14	2E-14	3E-14	3E-14	1E-13	2E-13	2E-12	2E-11	9E-10	1E-08	3E-08	3E-08	9E-08	1E-07	1E-07	1E-07	1E-07	1E-07	1E-07	1E-07	8E-08	4E-08	3E-08	3E-08	3E-08	4E-08	6E-08	3E-07	2E-06	8E-06	6E-06	3E-06	3E-06	2E-06	6E-07	2E-07	8E-08	3E-08	5E-09	1E-09	1E-09	3E-10
Qtr2	3E-09	1E-09	1E-10	2E-11	1E-11	1E-11	9E-12	3E-12	1E-12	2E-12	1E-11	2E-11	8E-11	9E-10	9E-08	5E-07	2E-06	2E-06	4E-06	5E-06	4E-06	4E-06	4E-06	5E-06	5E-06	5E-06	3E-06	2E-06	1E-06	1E-06	1E-06	1E-06	1E-06	2E-06	3E-06	3E-06	2E-06	3E-06	1E-06	1E-06	9E-07	2E-06	3E-06	1E-06	7E-07	1E-07	2E-08	4E-09
Qtr3	7E-09	1E-09	3E-10	2E-11	4E-12	2E-12	2E-12	2E-12	2E-12	3E-12	2E-11	3E-11	6E-11	2E-10	6E-09	6E-08	5E-07	1E-06	4E-06	6E-06	6E-06	6E-06	8E-06	8E-06	9E-06	1E-05	9E-06	7E-06	6E-06	7E-06	6E-06	7E-06	9E-06	9E-06	1E-05	1E-05	7E-06	5E-06	2E-06	1E-06	9E-07	1E-06	3E-06	2E-06	7E-07	1E-07	7E-08	3E-08
Qtr4	2E-10	3E-11	9E-12	2E-12	6E-13	2E-13	2E-13	2E-13	1E-13	9E-14	9E-14	1E-13	2E-13	7E-13	3E-11	1E-09	6E-09	1E-08	5E-08	1E-07	1E-07	1E-07	1E-07	2E-07	4E-07	5E-07	4E-07	2E-07	9E-08	6E-08	7E-08	1E-07	6E-07	6E-06	4E-05	6E-05	3E-05	2E-05	9E-06	6E-06	3E-06	8E-07	1E-06	3E-07	5E-08	9E-09	6E-09	1E-09
2012																																																
Qtr1	4E-11	7E-12	2E-12	6E-13	3E-13	9E-14	6E-14	5E-14	5E-14	4E-14	5E-14	9E-14	5E-13	6E-12	3E-10	8E-09	3E-08	2E-08	5E-08	7E-08	9E-08	1E-07	2E-07	2E-07	2E-07	2E-07	1E-07	6E-08	5E-08	5E-08	6E-08	1E-07	2E-07	1E-06	1E-05	2E-05	1E-05	5E-06	3E-06	1E-06	5E-07	2E-07	7E-08	2E-08	4E-09	8E-10	8E-10	2E-10
Qtr2	6E-10	8E-11	4E-11	2E-11	2E-11	1E-11	2E-11	2E-11	1E-11	1E-11	1E-11	3E-11	2E-10	1E-09	3E-08	4E-07	1E-06	1E-06	3E-06	5E-06	4E-06	4E-06	5E-06	6E-06	7E-06	7E-06	5E-06	3E-06	3E-06	2E-06	3E-06	3E-06	3E-06	4E-06	5E-06	4E-06	2E-06	7E-07	3E-07	2E-07	1E-07	6E-08	7E-08	8E-08	8E-08	3E-08	6E-09	2E-09
Qtr3	2E-12	5E-13	1E-13	1E-13	7E-14	5E-14	3E-14	3E-14	3E-14	4E-14	1E-13	1E-13	2E-13	7E-13	9E-12	1E-10	1E-09	4E-09	1E-08	4E-08	4E-08	4E-08	5E-08	7E-08	7E-08	8E-08	5E-08	3E-08	3E-08	2E-08	6E-08	6E-08	6E-08	1E-07	3E-07	4E-07	2E-07	6E-08	2E-08	1E-08	1E-08	2E-08	5E-08	2E-08	8E-09	1E-09	2E-10	2E-11
Qtr4	1E-12	8E-13	3E-13	1E-13	6E-14	2E-14	1E-14	1E-14	8E-15	8E-15	3E-14	7E-14	1E-12	2E-12	3E-11	4E-10	8E-10	8E-10	1E-09	3E-09	5E-09	6E-09	4E-09	3E-09	4E-09	4E-09	3E-09	1E-09	2E-09	3E-09	9E-09	2E-08	5E-08	6E-07	2E-06	1E-06	4E-07	2E-07	1E-07	4E-08	1E-08	7E-09	2E-09	4E-10	1E-10	1E-11	6E-12	1E-12
2013																																																
Qtr1	1E-09	1E-09	7E-10	3E-10	2E-10	1E-10	1E-10	9E-11	8E-11	8E-11	1E-10	2E-10	2E-10	1E-09	4E-09	2E-08	4E-08	8E-08	3E-07	4E-07	5E-07	5E-07	5E-07	5E-07	5E-07	5E-07	3E-07	1E-07	1E-07	1E-07	2E-07	2E-07	4E-07	9E-07	2E-06	2E-06	3E-06	6E-06	9E-06	5E-06	2E-06	1E-06	3E-07	8E-08	1E-08	2E-09	2E-09	1E-09
Qtr2	5E-11	4E-11	1E-11	6E-12	2E-12	7E-13	4E-13	1E-12	6E-13	4E-13	9E-13	1E-12	3E-12	1E-11	1E-10	4E-09	2E-08	3E-08	3E-08	3E-08	2E-08	3E-08	3E-08	2E-08	3E-08	2E-08	1E-08	6E-09	5E-09	3E-09	3E-09	4E-09	5E-09	9E-09	2E-08	1E-08	8E-09	4E-09	2E-09	1E-09	2E-09	7E-09	5E-09	1E-09	5E-10	9E-11	1E-10	2E-11
Qtr3	2E-11	4E-11	6E-12	3E-12	6E-12	3E-12	3E-12	2E-12	2E-12	3E-12	4E-12	8E-12	9E-12	2E-11	2E-10	1E-09	1E-08	2E-08	3E-08	3E-08	3E-08	4E-08	3E-08	4E-08	4E-08	5E-08	3E-08	2E-08	2E-08	2E-08	2E-08	3E-08	3E-08	6E-08	1E-07	2E-07	1E-07	7E-08	5E-08	9E-08	2E-07	2E-07	7E-08	2E-08	8E-09	1E-09	2E-10	4E-11
Qtr4	8E-12	5E-13	2E-13	1E-13	1E-13	9E-14	6E-14	7E-14	6E-14	7E-14	5E-14	9E-14	1E-12	2E-11	1E-10	1E-09	1E-09	6E-10	2E-09	4E-09	4E-09	4E-09	3E-09	3E-09	3E-09	3E-09	1E-09	8E-10	1E-09	1E-09	1E-09	2E-09	8E-09	1E-07	6E-07	8E-07	4E-07	1E-07	6E-08	3E-08	1E-08	6E-09	2E-09	3E-10	6E-11	3E-11	2E-11	6E-12
2014																																																
Qtr1	8E-12	2E-12	1E-12	6E-13	4E-13	2E-13	2E-13	1E-13	1E-13	1E-13	2E-13	2E-12	2E-11	2E-11	7E-11	3E-10	5E-10	4E-10	1E-09	2E-09	2E-09	4E-09	4E-09	3E-09	4E-09	4E-09	3E-09	2E-09	2E-09	2E-09	3E-09	4E-09	1E-08	2E-07	1E-06	3E-06	9E-07	3E-07	1E-07	6E-08	3E-08	1E-08	4E-09	7E-10	1E-10	3E-11	1E-11	8E-12
Qtr2	6E-11	5E-11	1E-11	9E-12	2E-11	7E-12	6E-12	7E-12	5E-12	5E-12	6E-12	6E-11	4E-10	1E-09	4E-09	2E-08	5E-08	4E-08	5E-08	7E-08	7E-08	8E-08	8E-08	8E-08	8E-08	8E-08	4E-08	3E-08	3E-08	2E-08	2E-08	2E-08	2E-08	3E-08	4E-08	3E-08	9E-09	4E-09	2E-09	7E-10	6E-10	5E-10	4E-10	2E-10	4E-10	3E-10	2E-10	2E-10
Qtr3	5E-10	1E-10	1E-10	1E-10	9E-11	4E-10	3E-10	3E-10	4E-10	4E-10	4E-10	2E-10	2E-10	5E-10	3E-09	2E-08	5E-08	2E-08	3E-08	6E-08	5E-08	6E-08	8E-08	9E-08	1E-07	8E-08	5E-08	3E-08	3E-08	3E-08	4E-08	6E-08	4E-07	7E-07	1E-06	9E-07	5E-07	2E-07	1E-07	1E-07	3E-07	6E-07	2E-07	3E-08	8E-09	2E-09	3E-09	7E-10
Qtr4	1E-11	8E-12	1E-11	7E-12	5E-12	3E-12	3E-12	4E-12	6E-12	6E-12	6E-12	8E-12	8E-12	2E-11	3E-10	1E-09	3E-09	2E-09	4E-09	5E-09	6E-09	6E-09	5E-09	5E-09	4E-09	4E-09	2E-09	4E-09	2E-09	2E-09	2E-09	2E-09	6E-09	2E-08	9E-08	1E-07	1E-07	5E-08	1E-07	2E-07	1E-07	4E-08	1E-08	4E-09	9E-10	1E-10	2E-11	1E-11
2015																																																
Qtr1	3E-12	2E-12	1E-12	7E-13	1E-12	4E-13	2E-13	1E-13	1E-13	1E-13	1E-13	7E-13	4E-12	6E-12	4E-11	3E-10	8E-10	8E-10	2E-09	9E-10	4E-10	4E-10	2E-10	2E-10	2E-10	3E-10	1E-10	4E-11	3E-11	4E-11	6E-11	8E-11	2E-10	7E-10	5E-09	4E-08	3E-08	3E-08	2E-08	9E-09	3E-09	1E-09	3E-10	5E-11	1E-11	3E-12	3E-12	4E-12
Qtr2	5E-11	1E-11	8E-12	6E-12	2E-11	2E-11	2E-11	1E-11	1E-11	1E-11	8E-12	4E-12	1E-11	6E-11	2E-10	7E-10	9E-10	4E-10	2E-10	5E-10	2E-10	1E-10	9E-11	8E-11	1E-10	1E-10	6E-11	4E-11	3E-11	4E-11	4E-11	5E-11	9E-11	2E-10	1E-10	1E-10	8E-11	4E-11	3E-11	4E-11	5E-11	7E-11	1E-10	4E-11	3E-11	1E-11	2E-11	2E-11
Qtr3	4E-09	6E-09	4E-09	3E-09	1E-09	8E-10	8E-10	2E-09	2E-09	1E-09	1E-09	8E-10	5E-10	3E-09	9E-09	2E-08	8E-08	2E-07	2E-07	4E-07	7E-07	7E-07	1E-06	7E-07	2E-07	2E-07	7E-08	5E-08	5E-08	4E-08	5E-08	4E-08	8E-08	2E-07	8E-07	2E-06	4E-07	2E-07	1E-07	9E-08	9E-08	8E-08	1E-07	6E-08	2E-08	9E-09	1E-08	9E-09
Qtr4	1E-09	2E-09	1E-09	9E-10	5E-10	4E-10	4E-10	5E-10	5E-10	3E-10	5E-10	9E-10	7E-10	1E-09	9E-09	1E-08	3E-08	2E-08	2E-08	3E-08	3E-08	2E-08	2E-08	2E-08	3E-08	2E-08	1E-08	6E-09	8E-09	1E-08	1E-08	1E-08	3E-08	2E-07	4E-06	5E-06	2E-06	9E-07	8E-07	3E-07	8E-08	2E-08	1E-08	4E-09	2E-09	2E-09	2E-09	2E-09
2016																																																
Qtr1	7E-11	5E-11	4E-11	3E-11	2E-11	2E-11	8E-12	1E-11	6E-12	5E-12	6E-12	8E-12	1E-11	6E-11	3E-10	4E-10	6E-10	4E-10	6E-10	6E-10	5E-10	4E-10	4E-10	5E-10	6E-10	4E-10	2E-10	2E-10	3E-10	2E-10	1E-10	2E-10	1E-09	7E-09	2E-08	1E-08	9E-09	1E-08	9E-09	4E-09	2E-09	1E-09	2E-10	6E-11	8E-10	1E-09	5E-09	2E-10
Qtr2	5E-08	3E-08	3E-08	3E-08	2E-08	2E-08	2E-08	2E-08	1E-08	1E-08	1E-08	1E-08	2E-08	2E-08	6E-08	9E-08	2E-07	2E-07	3E-07	2E-07	2E-07	3E-07	3E-07	3E-07	3E-07	2E-07	1E-07	1E-07	7E-08	9E-08	6E-08	7E-08	1E-07	1E-07	3E-07	4E-07	5E-07	6E-07	5E-07	5E-07	5E-07	4E-07	3E-07	3E-07	4E-07	2E-07	1E-07	9E-08
Qtr3	1E-09	3E-10	3E-10	2E-10	1E-10	6E-11	5E-11	3E-11	4E-11	4E-11	2E-11	3E-11	3E-11	1E-10	1E-09	5E-09	7E-09	5E-09	1E-08	8E-09	4E-09	5E-09	5E-09	5E-09	4E-09	3E-09	3E-09	2E-09	2E-09	1E-09	2E-09	2E-09	2E-09	5E-09	7E-09	7E-09	6E-09	8E-09	1E-08	2E-08	1E-08	1E-08	1E-08	2E-08	2E-08	2E-08	9E-09	3E-09
All	5E-06	3E-06	2E-06	1E-06	7E-07	6E-07	6E-07	5E-07	5E-07	4E-07	5E-07	4E-07	2E-06	4E-06	2E-05	1E-04	4E-04	5E-04	9E-04	0.001	0.001	0.001	0.001	0.001	0.001	0.001	8E-04	6E-04	7E-04	6E-04	7E-04	7E-04	8E-04	0.002	0.004	0.005	0.003	0.002	0.002	0.001	9E-04	6E-04	4E-04	2E-04	8E-05	3E-05	1E-05	5E-06

APPENDIX B DSU SHUTDOWN COSTS

We have updated the analysis of DSU cost structures presented in CRM Decision 1. The below analysis of existing DSU's based upon bids submitted during the week ending 21 August 2016[52]. DSU's can submit up to three incremental bid prices to the SEM, as well as a "shutdown" cost, and minimum and maximum shutdown times[53]. There is no reason to believe these cost structures will change significantly with the move to the I-SEM.

These values indicate that:

- All 320MW had an incremental bid price of less than €400/MWh;
- Of the 320MW of existing demand side response, 266MW (83%) had a cost of less than €500/MWh if asked to shut-down and provide demand side response for only 1 hour. We note that a number of DSUs submitted technical data which allowed them to be shut down for less than 1 hour, but it is unlikely that a scarcity event would last for less than 1 hour.

RESOURCE_NAME	Cost/MW @ 1 hour shutdown (EUR/MW)	Cost / MW@ max down time (EUR/MW)	Incremental Cost Bid (EUR/MW)	Quantity (MW)	Cumulative MW
DSU_401610	21.14	- 42.69	- 42.75	9.00	9.00
DSU_401400	279.06	279.06	279.06	23.00	32.00
DSU_401490	332.37	321.68	311.00	19.00	51.00
DSU_401590	339.52	234.78	147.49	20.08	71.08
DSU_401850	411.41	362.39	313.37	15.30	86.38
DSU_401620	420.51	354.11	313.37	14.00	100.38
DSU_401330 combined	437.24	408.62	350.00	22.41	122.79
DSU_401800	452.49	382.93	313.37	10.78	133.57
DSU_401530	478.23	404.12	330.00	33.69	167.26
DSU_401270	486.14	411.91	337.68	99.00	266.26
DSU_501380	1,193.00	771.40	307.40	20.00	286.26
DSU_501330	1,521.29	971.84	371.20	18.35	304.60
DSU_401660	2,190.00	1,290.00	390.00	5.00	309.60
DSU_401390	2,602.73	348.94	330.00	11.00	320.60

Note that DSU_401330 submitted a three-part bid, but to simplify the apportionment of shutdown costs, we have assumed that the incremental bid price for all three parts was equal to the most expensive bid segment, at €350/MWh

[52] Where bids were in GBP from Northern Ireland based bidders these have been converted at an exchange rate of £1=1.16EUR

[53] All but one unit submitted only one incremental bid. To simplify the analysis, for that bid we have taken its most expensive incremental bid and assume it applied to all its bid segments

APPENDIX C IMPACT OF THE RELIABILITY OPTION AND ASP ON INFRA-MARGINAL RENT

Impact of ASP and RO of values per MW of BNE nameplate capacity (excludes impact of move from 5.91% FOP, and move to expressing cost per kW *derated* capacity)

I-SEM ASP scenario	Outage Scenario	Capacity component	SEM IMR	I-SEM IMR
Full (8 hours @ €3,000/MWh)	Forced outage (5% of time)	De-rated (5% of capacity)	0	0
		Covered by RO (95% of capacity)	0	-(3,000 - SP) x 8 x 5% x 95% = -950
	Running (95% of time)	De-rated (5% of capacity)	(1,000 – FC) x 8 x 95% x 5% = 317.47	(3,000 - FC) x 8 x 95% x 5% = 1,077.47
		Covered by RO (95% of capacity)	(1,000 – FC) x 8 x 95% x 95% = 6,031.88	(500 - FC) x 8 x 95% x 95% =2,421
Partial ASP (4 hours @ €1,500/MWh)	Forced outage (5% of time)	De-rated (5% of capacity)	0	0
		Covered by RO (95% of capacity)	0	-(1,500 - SP) x 4 x 5% x 95% = -190
	Running (95% of time)	De-rated (5% of capacity)	0	(1,500 – FC) x 4 x 95% x 5% = 253.73
		Covered by RO (95% of capacity)	0	(500 – FC) x 4 x 95% x 5% = 1,210.94
Total €/MW p.a.			6,349.44	3,824.02
Total €/kW p.a.			6.35	3.82

Note: SEM 2017 fuel cost = €164.56/MWh; SP assumed = €500/MWh