Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism (CRM)

Parameters for T-4 2022/23 Capacity Auction

Consultation Paper

SEM-18-028

14 May 2018

EXECUTIVE SUMMARY

The I-SEM CRM Detailed Design has been developed through an extensive series of consultation and decision papers. This involved substantial interaction between stakeholders, including both System Operators and Industry. Decisions made during the Detailed Design were translated into auction market rules to form the Capacity Market Code (CMC) (SEM-17-033) which was published in June 2017. The CMC sets out the arrangements whereby market participants can qualify for, and participate in, auctions for the award of capacity. The settlement arrangements for the Capacity Remuneration Mechanism (CRM) form part of the revised Trading and Settlement Code (TSC) (SEM-17-024) published in April 2017.

The EC gave State aid approval for the CRM on 24 November 2017.

The CY2018/19 Capacity Auction took place in December 2017. Following the completion of the CY2018/19, the SEM Committee is now planning to proceed with the CY2019/20 T-1 auction in December 2018, and the CY2022/23 T-4 auction in March 2019.

In SEM-18-009 the SEM Committee consulted on the parameters for the T-1 CY2019/20 auction.

The purpose of this consultation paper is to:

- Provide an update on aspects of the CRM design including those areas for which interim arrangements have been put in place;
- Consult on specific areas of the CRM auction design in light of the updates mentioned above; and
- Consult on specific parameters for the first T-4 capacity auction for capacity year 2022/23.

The assessment criteria to inform decisions is set out in Section 1.2 and is consistent with that used for the CRM detailed design. However, all elements of the design and parameters should be consistent with any undertaking given to the European Commission as part of the State aid approval, and any other EU regulations- all of which are consistent with meeting the EU Internal Market criteria set out in this section.

In Section 2, Treatment of Constraints in T-4 Auction, the SEM Committee is consulting on the proposal to reflect transmission constraints in the first T-4 auction. The results of the CY2018/19 auction reinforced the need to manage exit, as an unconstrained auction would not have delivered the minimum MW required for capacity adequacy in the greater Dublin area or Northern Ireland.

There are a number of uncertainties, which indicate that there is a need to manage exit and/or entry in CY2022/23 via the inclusion of transmission constraints in the CRM auction, including progress on resolving existing constraints, significant demand growth uncertainty and the need to ensure the right outcome for consumers when considering bids from existing plant and new plant bids.

Whereas the key constraint issues in the transitional auction predominantly relate to the need to manage exit, there may also be a need to make changes to the auction design / auction clearing to facilitate efficient new entry in constrained areas.

In Section 2.2, the SEM Committee discusses a proposal to allow multi-year pay-as-bid Reliability Options in the first T-4 auction to ameliorate the issue of managing exit and entry of plant.

In Section 3 Auction Format, the intention is to retain the majority of the auction design employed in the CY2018/19 and CY2019/20 transitional auctions. However, two changes are proposed to meet the key objectives of:

- **Compliance with the State aid commitments not to over procure**: As part of the State aid process, the authorities in Ireland and Northern Ireland gave an undertaking to the EC that from CY2020/21 onwards, any capacity awarded out-of-merit Reliability Options for locational capacity constraint reasons should not be additional to the capacity secured in merit. Consequently, if out-of-merit volumes need to be procured to satisfy locational constraints, this will displace in-merit generation elsewhere. The CY2022/23 T-4 auction will be the first auction for which this change applies; and

- **Optimise outcome of T-4 auction from assessment of new and existing plant bids:** Changes to the auction format to facilitate the option proposed in Section 2.2 aimed at ensuring the right outcome for consumers when considering bids from existing plant and new plant bids. The option proposed is to allow new capacity seeking a multi-year pay-as-bid offers to compete for a pay-as-bid Reliability Option up to the value of Net CONE.

Consequently, the auction format that applied to the T-1 CY 2018/19 requires modifications to address the State aid decision to displace equivalent MW of in-merit generation to allow for out of merit capacity required to meet the minimum requirement of an identified significant constraint area. The SEM Committee note that while the approach to price determination is expected to remain unchanged, the approach to winner determination must change to align with the State aid decision.

In Section 4 Capacity Requirement, the SEM Committee reflect on aspects informing the capacity requirement so as to ensure that the right balance is struck in determining this key input into the Auction Demand Curve. The Capacity Requirement is determined by the TSOs, based upon policy decisions and a methodology approved by the SEM Committee. Two of the key policy decisions relate to level of the Loss of Load Expectation (LOLE) standard and whether to include operating reserves in the Capacity Requirement. In Section 4 the SEM Committee consults on whether to:

- Tighten the LOLE standard, which could add as much as 250MW to the Capacity requirement; and/or
- To include some or all of the 500MW maximum operating reserve requirement in the CY2022/23 Capacity Requirement.

Whilst the existing Capacity Requirement methodology was appropriate for the CY2018/19 auction, and remains appropriate for CY2019/20, given additional procurement to meet significant constraints, the SEM Committee is consulting on their application to CY2022/23 in the light of:

- Increasing clarity over the “direction of travel” of moves towards European harmonisation of Capacity Requirement methodologies, although, as yet, there is no harmonised standard;
- Suggestions that a theoretical 8-hour LOLE standard would in practice result in more hours of lost load when “demand control” actions are taken account of; and

- The commitment not to procure additional capacity in respect of locational capacity constraints from CY2020/21, and the potential weakening of other factors which ensured a conservative approach to capacity procurement in CY2018/19 and CY2019/20.

In Section 5 Administered Scarcity Pricing Parameters, the SEM Committee review the value and percentage of Value of Lost Load to be applied in determining the ASP parameters. During the CRM Detailed Design phase, the SEM Committee decided that, for the transitional period (to the end of CY2021/22) the value of the Full Administered Scarcity Price (Full ASP) would be set at €3,000/MWh for a transitional period and that the Full ASP value would be set as a percentage of the Value of Lost Load (set at €11,128/MWh in 2018), from the start of CY2022/23. The SEM Committee is now consulting on the percentage of VoLL to apply from CY2022/23, with options consider in the range of 25% of VoLL to 100% of VoLL.

In Section 6 Auction Volumes and Demand Curve, the SEM Committee consults on CY2022/23 auction volumes and the demand curve. The key issues are:

- Whether to increase the proportion of the Capacity Requirement to withhold from the T-4 auction to the T-1 auction from 5%, in the light of the high level of participation of demand side response in the CY2018/19 T-1 auction;
- Whether to hold back volume from the Level 1 and Level 2 areas' minimum MW requirements in the T-4 auction, or just to withhold volume at an all-island level; and
- Whether to make a change to the shape of the demand curve used in the CY2018/19 auction, for the T-4 auction, if offered prices are above Net CONE. Where prices are above Net CONE in a T-4 auction, more capacity can be procured in the T-1 auction.

In Section 7 T-4 Auction Price Caps for Capacity Year 2022/23, the SEM Committee consults on the Auction Price Caps to apply in the CY2022/23. The SEM Committee is consulting separately in the CRM T-4 Best New Entrant consultation (SEM-18-025)[1] on a revised BNE Net CONE to apply in CY2022/23. In this consultation document, the SEM Committee sets out its intention to set the Auction Price Cap at 1.5 x Net CONE and the Existing Capacity Price Cap at 0.5 x Net CONE for the CY2022/23 T-4 auction, the same value as applied in the CY2018/19 transitional auction. Section 7 sets out some further detail on information requirements in respect of Exceptions Applications.

Section 8 De-rating Factors, the SEM Committee considers the various factors influencing the Interconnector de-rating for the first T-4 auction. This includes consideration of:

- How to generate the updated input assumptions for CY2022/23; and
- Issues associated with the move from the interim "interconnector-led" solution to the hybrid solution, in accordance with State aid undertaking to allow direct participation of cross-border capacity from auction occurring in 2020 or later.

The RAs' final interconnector de-rating factors will be included in the Initial Auction Information Pack.

[1] https://www.semcommittee.com/news-centre/i-sem-crm-t-4-cy202223-best-new-entrant-consultation

Section 9 New Capacity Investment Rate Threshold, the SEM Committee proposes to keep the New Capacity Investment Rate Threshold at €300/de-rated kW, based on the revised estimate of BNE costs set out in the CRM T-4 Best New Entrant Consultation (SEM-18-025).

Section 10 Summary of T-4 2022/23 Parameters, provides an overview of the proposed parameters for the first T-4 capacity auction for capacity year 2022/23.

Responses to this consultation should be submitted to Karen Shiels (Karen.Shiels@uregni.gov.uk) and Kevin Lenaghan (Kevin.Lenaghan@uregni.gov.uk) by 17.00 on Tuesday, 26 June 2018. Please note that we intend publishing all responses unless marked confidential.

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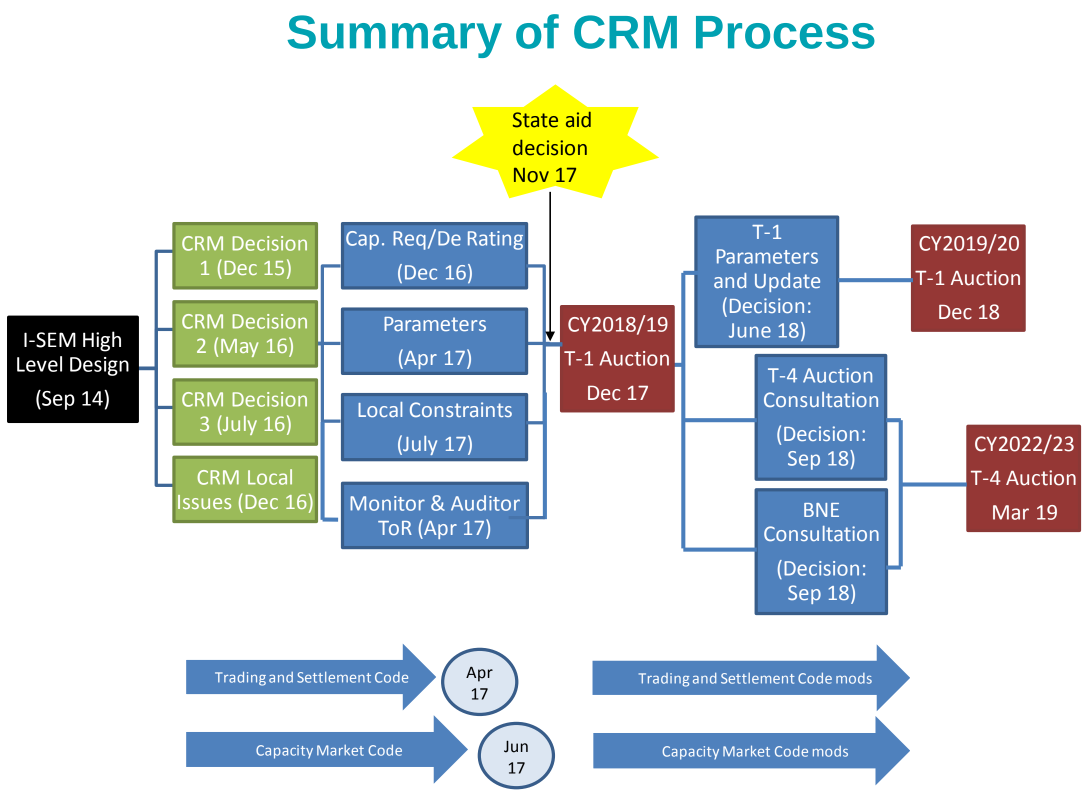
1. OVERVIEW

1.1 BACKGROUND

1.1.1 The I-SEM CRM Detailed Design has been developed through an extensive series of consultation and decision papers. This involved substantial interaction between stakeholders, including both System Operators and Industry. This interaction took the form of numerous workshops and meetings in addition to the feedback from the consultations.

1.1.2 Decisions made during the aforementioned consultations were translated into auction market rules to form the Capacity Market Code (CMC) (SEM-17-033) which was published in June 2017. The CMC sets out the arrangements whereby market participants can qualify for and participate in auctions for the award of capacity. The settlement arrangements for the Capacity Remuneration Mechanism (CRM) form part of the revised Trading and Settlement Code (TSC) (SEM-17-024) published in April 2017. A summary of this process is shown in Figure 1 below, along with key CRM development milestones over the next 12 months.

Figure 1: Key CRM milestones



1.1.3 The introduction of the CRM involved formal notification to the European Commission (EC) of the proposed mechanism for purposes of State aid. This process was led by Department of Communications, Climate Action & Environment (DCCAE) and Department for the Economy (DfE) who together with the Regulatory Authorities (CRU and UR) engaged with the EC in advance of the notification and during the notification process.

1.1.4 The EC approved the CRM on 24 November 2017[2]. The first Capacity Auction took place in December 2017 to cover the period from I-SEM go-live to 30 September 2019, i.e. CY 2018/19. Following the completion of the CY2018/19 transitional auction, the SEM Committee is now planning for the next auctions.

1.1.5 The next T-1 auction for CY2019/20 is planned for December 2018, and the first T-4 auction for CY2022/23 is planned for March 2019.

1.1.6 The purpose of this paper is to:

- Provide an update on aspects of the CRM design including those areas for which interim arrangements have been put in place;
- Consult on specific areas of the CRM auction design in light of the updates mentioned above; and
- Consult on specific parameters for the first T-4 capacity auction for capacity year 2022/23.

1.1.7 Some of the parameter values are captured in the CMC. Others are captured within the Trading and Settlement Code (TSC) since Capacity Market settlement is governed by the TSC, and some of these parameters are regulatory parameters which the RAs/SEM Committee will apply in regulating auction bids, but are set outside the CMC and TSC.

1.1.8 This first T-4 auction is provisionally scheduled for late March 2019, the date is expected to be confirmed in June/July 2018 when the auction timetable is scheduled for publication.

1.1.9 As part of the first parameter consultation[3] on the first T-1 Capacity Auction the SEM Committee committed to consult again on T-4 capacity auction parameters in advance of the first capacity auction for 2022/23**.** This consultation sets out a complete set of T-4 capacity auction parameters for the capacity year 2022/23. It is envisaged that some of these parameters will remain unchanged from the first T-1 capacity auction for the period 2018/19, however where changes are proposed the rationale to support the proposed change is provided.

1.1.10 The SEM Committee also committed to consulting on the assumptions (including the Weighted Average Cost of Capital (WACC)) used in setting the Best New Entrant/Net Cost of New Entry (BNE/Net CONE) before the first T-4 auction for Capacity Year 2022/23. The rationale being that significantly more new entry is expected to participate in the first T-4 auction due to the longer development lead time to deliver capacity from 1 October 2022. This is being consulted upon separately by the SEM Committee within the CRM T-4 Best New Entrant consultation (SEM-18-025)[4]. The decision on the BNE/Net CONE will be a key driver in setting the following auction parameters for the T-4 capacity auction:

[2] http://ec.europa.eu/competition/state_aid/cases/267880/267880_1948214_166_2.pdf

[3] SEM-17-022 https://www.semcommittee.com/publication/publication-crm-parameters-decision
[4] https://www.semcommittee.com/news-centre/i-sem-crm-t-4-cy202223-best-new-entrant-consultation

- Auction Price Cap (APC);
- Existing Capacity Price Cap (ECPC);
- New Capacity Investment Rate Threshold (NCIRT).

1.1.11 The SEM Committee's decision papers, T-4 parameters and BNE/Net CONE, for the first T-4 capacity auction are expected to be published September 2018. These will inform the T-4 CY2022/23 Initial Auction Information Pack due to be published shortly after the SEM Committee has published the above mentioned decision papers.

1.2 ASSESSMENT CRITERIA

1.2.1 Assessment criteria for the detailed design 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. The 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.

1.2.2 All elements of the design and parameters should be consistent with any undertaking given to the European Commission as part of the State aid approval, and any other EU regulations- all of which are consistent with meeting the EU Internal Market criteria.

2. TREATMENT OF CONSTRAINTS IN T-4 AUCTION

2.1 INCLUSION OF TRANSMISSION CONSTRAINTS IN T-4 AUCTION

2.1.1 In the CRM Locational Issues decision (SEM-16-081), we decided to reflect transmission constraints in the transitional T-1 auctions, in the context of needing to manage the location of plant exit.

2.1.2 We deferred the decision on whether to reflect transmission constraints in the first T-4 auction.

2.1.3 In SEM-16-081 we stated that:

- "*The SEM Committee agrees with a number of respondents who argue that it is appropriate to review locational signals (GTUoS and TLAFs) which may provide at least partial solutions to the handling of transmission constraints in T-4 auctions. However, it is not clear to what extent it will be possible to complete a full review of locational signals sufficiently prior to the first T-4 auction to ensure that they will provide a sufficient solution to constraints in the CRM, without the application of other measures too;*
- *It is important that longer term locational constraints are addressed and to ensure the most efficient means of solving these constraints is sought for the benefit of consumers. This requires the continued assessment of network investment and any other actions by the TSOs which could lead to cheaper alternatives to the inclusion of constraints within the CRM auctions.*
- *At this time, we cannot be sure to what extent we can be sufficiently confident that transmission constraints will be alleviated prior to the first T-4 auction that there will be no requirement to reflect transmission constraints in the first T-4 auction. We will therefore require the T-4 auction system (including one that implements Auction Format Option D) to be capable of handling a range of identified transmission constraints;*
- *However, before making a decision to implement them in the first T-4 auction, we would propose to consult again on the pros and cons of including them in that auction, at a time closer to the first T-4 auction, when more is known about the scale of plant exit, and more information is known on progress in reviewing locational signals, and in reinforcing the transmission system;*"

2.1.4 We are now consulting on our proposal to reflect transmission constraints in the first T-4 auction.

2.1.5 The results of the CY2018/19 auction reflects the importance of including locational capacity constraints within a capacity auction when significant transmission constraints exist, as an unconstrained auction would not have delivered the minimum MW required for capacity adequacy in the greater Dublin area or in Northern Ireland. The inclusion of transmission constraints in the CY2018/19 auction led to the award of an additional 399MW of out-of-merit Reliability Options in Dublin and 126MW in Northern Ireland. The ability to manage plant exit was particularly important in the light of the fact that in the transitional auction, there is limited scope for new entry, other than new generation not requiring significant capital expenditure. This is evidenced - with new entry in the CY2018/19 being largely confined to around 250MW of new DSU capacity.

2.1.6 At the current time, the SEM Committee is aware of the possible need to manage plant exit and/or new entry in CY2022/23. This possibility should be reduced, as the Capacity Market will no longer award 'additional' capacity to satisfy capacity constraints in the CY2020/21 and CY2021/22 transitional auctions. Consequently, it might be expected that exit signals may be sent to capacity located in the over-supplied region(s)[5]. This in turn may reduce the need for further management of exit by CY2022/23.

2.1.7 In addition to the approach of including transmission constraints in the auction, there are a number of tools which are available to manage locational capacity issues, including:

- Transmission system reinforcement; and
- Locational signals for capacity and/or demand, which can send exit and/or entry signals for both capacity and demand.

2.1.8 There are, however a number of uncertainties, which indicate the continued need to manage exit and/or entry in CY2022/23 via the inclusion of transmission constraints in the CRM auction, namely:

- Whilst progress is likely to be made on resolving the key North-South transmission constraints (which caused the existence of Level 1 areas for Ireland and Northern Ireland in CY 2018/19) and the greater Dublin area (which caused the existence of the Level 2 greater Dublin area in CY2018/19), for each of these areas there remains significant challenges before assurance that these transmission capacity constraints will be resolved by CY2022/23 is certain;

- Based upon the latest published TSOs Generation Capacity Statement[6] there is significant demand growth forecast for Ireland in the high growth demand scenarios, with a significant proportion likely to be driven by data centres locating in the currently constrained greater Dublin area. In the high demand growth scenario, the all-island TER peak demand growth is forecast to grow by 600MW from 7.18GW in 2018 to 7.78GW in 2023, with a significant proportion of that demand growth reasonably likely to take place in and around the greater Dublin area. There is however, significant uncertainty around the growth forecasts, with growth of only 350MW over the corresponding period in the median scenario and of only 260 MW in the low growth scenario;

- We cannot be sure that those units which were not awarded a Reliability Option in CY2018/19, or subsequent years will/or will not have exited by CY2022/23. There may

[5] Which in the CY2018/19 transitional auction was the Level 1 Ireland zone, excluding the Level 2 area of greater Dublin.

[6] Eirgrid/SONI 2017 – 2026 Generation Capacity Statement. Note that an updated Generation Capacity Statement is anticipated to be published shortly.

be a competitive response from some existing plant which was not awarded a Reliability Option in CY2018/19, so the geographical distribution of those awarded in merit Reliability Options may change from year to year, competitive forces coming to bear;

- Whilst there may be a stronger exit signal for certain plant in an over-supplied area as a result of the State aid commitment not to award additional capacity in respect of transmission constraints from CY2020/21, it is not clear that affected plant will exit- particularly if they believe that they will be awarded a Reliability Option in a future unconstrained auctions;

- The latest draft of the Energy Package has a CO2 emissions limit of 550g/kWh[7], for plant participating in a capacity mechanism, without any dispensation for plant with limited hours. Under the current draft, existing plant would have 5 years to comply with the legislation, so were the Directive to become law in 2020, as is the current expectation, then compliance would be needed by 2025. Now whilst compliance may not be required before 2025, it could start impacting exit decisions earlier. For instance, any plant affected which is due a major overhaul in 2023, may decide that it is uneconomic to make the investment;

- It is not clear where the most competitive locations for new entry will be. In the absence of meaningful changes to locational signals, for which time has not permitted the RAs to implement in advance of the T-4 Auction, the most competitive locations may be where spare transmission capacity / connections exist, which by CY2022/23 could be close to where capacity has recently exited.

2.1.9 In the EC State aid decision, the Commission underlined the importance of implementing market reforms, in particular in the ancillary services market, that reward the locational value of plant, as a condition to move away from the separate procurement of locationally important plant.

2.1.10 A full and comprehensive review of locational signals are unlikely to be implemented in time to provide appropriate locational signals prior to the first T-4 auction in March 2019, or before Unit Specific Price Caps (USPCs) need to be set in late 2018. Some reforms which provide a degree of locational signalling for exit/entry may be implemented before March 2019, and it may be possible for the SEM Committee to signal its intent on other reforms to locational signals.

2.1.11 While the key constraint issues in the transitional auctions predominantly relate to the need to manage exit[8], there may be a need to make changes to the auction design / auction clearing to facilitate efficient new entry in constrained areas so as to maximise value for consumers. Therefore, in Section 2.2, we discuss a proposal to allow multi-year pay-as-bid Reliability

[7] Directive: COM(2016) 861, common referred to as part of the Clean Energy Package
[8] given that the nature of a T-1 auction timeline is a significant barrier to entry for many technologies

Options to participate within constrained areas in the T-4 auction, which may result in a more efficient balance between managing exit and entry.

2.1.12 We have consulted with the TSOs, and they have advised that…

"*The System Operators believe that it is appropriate to include the Locational Capacity Constraint analysis as part of the T-4 auction process. Carrying out this analysis ensures that the RAs are in a position to make an informed decision about the need for Locational Capacity Constraints based on a clear well defined methodology.*

Rather than presume that no capacity constraints exist in the 2022/23 Capacity Year, the System Operators believe that it would be prudent to carry out the Locational Capacity Constraints analysis and allow this process to identify if constraints are likely to exist. If the analysis does not identify any constraints then the auction proceeds unaffected without Locational Capacity Constraint areas defined; if however constraints are identified, then it is possible for these constraints to be included in the auction.

It is therefore important for maintaining security of supply in Ireland and Northern Ireland that the T-4 auction include the Locational Capacity Constraint analysis".

2.1.13 **Given the level of uncertainty identified above, and the fact that a full suite of reforms to locational signals are unlikely to be in place prior to the auction, we consider it important to include constraints in the first T-4 auction**.

2.1.14 This means that the CRM T-4 auction system will be built to accommodate transmission constraints, with the potential to accommodate Level 1 and Level 2 constrained areas, as with the transitional auctions. The final decision on whether there are material constraints, and the definition of the Level 1 and Level 2 constrained areas will be made by the SEM Committee prior to the issue of the Initial Auction Information Pack based on the TSOs' analysis.

2.1.15 We note that the inclusion of transmission constraints can result in the sum of the Level 1 minimum MWs exceeding the all-island Capacity Requirement. In CY2018/19, the Level 1 minimum MW requirement for Ireland was 5,260MW and the Level 1 minimum MW requirement for Northern Ireland was 1,630MWs. The sum of these Level 1 requirements was 6,890MW, so these requirements could not be satisfied without 6,890 MW of Reliability Options. This was 170MW more than the all-island Capacity Requirement due to diversification effects. Whilst in CY2018/19 there were other drivers of procurement exceeding the all-island Capacity Requirement, the sum of the Level 1 minimum MW could set a floor on the MWs procured in CY2022/23.

2.2 TRANSMISSION CONSTRAINTS AND MULTI-YEAR PAY-AS-BID RELIABILITY OPTIONS

2.2.1 The CRM Locational Issues Decision Paper (SEM-16-081) stated that multi-year pay-as-bid Reliability Options would not be allowed in the transitional auctions, although it may be necessary under certain circumstances[9].

2.2.2 SEM-16-081 further stated that, "*If at any future point in time, a transmission constraint was incorporated in a T-4 auction, we would consider separately whether a New Build generator in the T-4 auction would be eligible for a multi-year pay-as-bid contract. In that case, considerations would be different since:*

- *There is more scope for competition from a wider range of technologies in the T-4 auction;*
- *The fact that the constraint was incorporated in the T-4 auction would be recognition that the constraint was less transitory*."

2.2.3 Therefore, it is now appropriate to consider whether or not we will award multi-year pay-as-bid Reliability Options in the first T-4 auction, and if so under what circumstances.

2.2.4 In the first transitional auction, single year pay as bid Reliability Options were awarded at prices of up to £91.37/kW/year. This value was substantially higher than the clearing price of £38.10/kW/year, and higher than Net CONE which was £73.64/kW/year.

2.2.5 As anticipated, there were no investors making a Substantial Financial Investment[10] in the first transitional auction, so the issue of choosing between a cheaper multi-year bid and a more expensive one-year bid to meet a locational constraint was not relevant. However, consider a hypothetical case in the first T-4 auction whereby the clearing price is £38.10/kW/year as before, and the TSOs need to choose between a 10-year fixed price offer at £40.00/kW/year or a single year offer at £91.37/kW/year.

2.2.6 Now in this case, there would be arguments in favour of accepting the 10-year fixed price offer in preference to the single year offer at £91.37/kW/year. Locking-in to a price of £40.00/kW/year would expect to be a more economical outcome for the consumer:

- Importantly, unlike the transitional auctions, there is expected to be reasonable scope for competition from new entrants in T-4 auctions, so it is significantly more likely that

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[9] We stated that," *There may need to be some exceptions to the rule that a New Build capacity provider cannot get a multi-year Reliability Option in a transitional auction, if there is no other way that the minimum capacity requirement in a constrained zone can be met. For instance, suppose in the above example, the existing plant was no longer able to continue supporting security of supply (e.g. because of a permanent failure of a plant), and new build capacity was necessary to ensure local security of supply. If the best new entrant needed to obtain a 10-year Reliability Option at Net CONE (indicatively around €78/kW p.a. in SEM-16-073), to justify new investment, but the all-island unconstrained clearing price was around the ECPC at 0.5 x Net CONE we may need to accommodate some form of longer term higher priced contract. Should such circumstances arise, we will consider appropriate arrangements on a case by case basis.*"

[10] of more than €300/kW, the New Capacity Investment Rate Threshold

the multi-year fixed price Reliability Option has won in a competition with fewer barriers to entry; and

- The offered price is well below the estimated Net CONE, so there is no evidence that the capacity provider has exploited barriers to entry to lock-in a high priced multi-year Reliability Option.

2.2.7 The SEM Committee is considering the following possible options:

- Option 1: As with, the transitional auctions, allowing multi-year pay-as-bid Reliability Options, only where there are no other solutions available to satisfy the minimum MWs in the constrained area;
- Option 2: Allowing multi-year pay-as-bid Reliability Options to compete on the same basis against single year offers, but only where the multi-year offer is priced at or below Net CONE (possibly with the addition of a small tolerance); or
- Option 3: Allowing multi-year pay-as-bid Reliability Options to compete against single year offers at any price up to the Auction Price Cap.

2.2.8 In Option 2, multi-year out-of-merit offers would compete with single-year out-of-merit offers on the same basis as in-merit offers (i.e. based on price and Net Social Welfare) up to Net CONE, but would only be accepted above Net CONE if there was no other way to meet the minimum MW requirement. The SEM Committee sees advantages in Option 2 in preference to the status quo in transitional auctions (Option 1), with those advantages highlighted in the above hypothetical example. The key risk with Option 2 is that it may result in a stranded longer-term Reliability Option, if the constraint does not persist for the full duration of Reliability Option. However, if the multi-year Reliability Option is priced at or below Net CONE, the risk that it is stranded in later years, and the cost to the consumer of stranding are more limited.

2.2.9 The SEM Committee sees disadvantages in Option 3. In the above hypothetical example, it would mean that a 10-year Reliability Option could be awarded at a price of £91.36/kW/year in preference to a 1-year RO at £91.37/kW/year. It could result in long-term high-priced ROs, if capacity providers are able to exploit barriers to entry in a constrained area to offer at prices well above Net CONE.

2.2.10 In the CRM detailed design phase, we rejected options which consider more complicated trade-offs between price and duration, as being too difficult to implement initially. Such options remaining impractical for the first T-4 auction.

2.2.11 While the focus of this consultation paper and the above proposal and options is on the first T-4 capacity auction the SEM Committee is aware there may be a need for the Regulatory Authorities to consider wider locational elements whilst being mindful of market impacts.

2.3 SUMMARY OF CONSULTATION QUESTIONS

2.3.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you agree with the SEM Committee's proposal to reflect transmission constraints in the T-4 auction? Please explain your rationale.

2) Do you have any comment on the possible inclusion of multi-year pay-as-bid Reliability Options to meet the minimum Locational Capacity Constraint requirement?

3) Do you have a preference between the options set out above in relation to pay-as-bid offers? Please explain your rationale.

3. AUCTION FORMAT

3.1 INTRODUCTION

3.1.1 The SEM Committee proposes to reflect transmission constraints in the first T-4 auction, as was the case for the CY2018/19 T-1 auction. The SEM Committee proposes to retain the majority of aspects of the auction design employed in the CY2018/19 and forthcoming CY2019/20 transitional auctions.

3.1.2 Two changes are being proposed to the auction design applied to the CY2018/19 auction. The proposals aim to meet the key objectives of:

- **Compliance with the State aid commitments not to over procure:** As part of the State aid process, the authorities in Ireland and Northern Ireland gave an undertaking to the EC that from CY2020/21 onwards, any capacity awarded out-of-merit Reliability Options for locational capacity constraint reasons should not be additional to the capacity secured in merit. Consequently, if out-of-merit volumes need to be procured to satisfy locational constraints, this will displace in-merit generation elsewhere. The CY2022/23 T-4 auction will be the first auction for which this change applies; and

- **Optimise outcome of T-4 auction from assessment of new and existing plant bids:** Changes to the auction format to facilitate the option proposed in Section 2.2 aimed at ensuring the right outcome for consumers when considering bids from existing plant and new plant bids. The option proposed is to allow new capacity seeking a multi-year pay-as-bid offers to compete for a pay-as-bid Reliability Option up to the value of Net CONE.

3.1.3 The two key changes being proposed for the T-4 auction:

a) A change required to the "winner determination" approach to ensure that the auction does not procure additional capacity in respect of transmission constraints. This change is necessary to comply with State aid undertakings. As explained in the recent T-1 CY 2019/20 Parameters consultation (SEM-18-009), as part of the State aid process, the authorities in Ireland and Northern Ireland gave an undertaking to the EC that from CY2020/21 onwards, **any capacity awarded out-of-merit Reliability Options for constraint reasons should not be additional to the amount of in-merit capacity procured on an all-island basis**. If out-of-merit volumes need to be procured to satisfy locational capacity constraints, this will displace in-merit generation. The CY2022/23 T-4 auction will be the first auction for which this change applies;

b) A change required to the "winner determination" approach to facilitate the change set out in Section 2.2, to allow multi-year pay-as-bid Reliability Options, at a price up to Net CONE. Any accepted, out-of-merit offers will be paid-as-bid as before.

3.1.4 No changes are proposed to the "price determination" approach applied in the CY2018/19 T-1 auction. Accepted in-merit offers will continue to be paid the clearing price, which will be set based on the unconstrained schedule. Any out-of-merit bids accepted for transmission constraints or for "lumpiness" reasons will continue to be paid-as-bid.

3.1.5 In order for respondents to understand and comment on the proposed T-4 auction design, the remainder of this Section in structured as follows:

- In Section 3.2, we begin with a recap of the CY2018/19 T-1 auction design, including a simplified worked example;
- In Section 3.3, and the associated Appendix A, we set out the proposed changes to the auction design to comply with the State aid commitment not to procure additional capacity in the CY2022/23 T-4 auction;
- In Section 3.4, we describe how the proposals in Section 2.2 to allow multi-year pay-as-bid Reliability Option (up to Net CONE) will impact the T-4 auction design;
- In Section 3.5, we summarise the consultation questions.

3.2 RECAP OF CY2018/19 T-1 AUCTION DESIGN

Policy and CMC background

3.2.1 In CRM Decision 3 (SEM-16-039), the SEM Committee made a number of key auction design decisions such as:

- Bid structure: To allow up to 5 price quantity pairs to be offered, with a provision to bid inflexibly, creating the so-called "lumpiness" issue;
- Managing lumpiness: To use the Net Social Welfare criteria, where Net Social Welfare is based on the sum of consumer surplus and producer surplus; and
- Processes for managing tied bids.

3.2.2 However, in SEM-16-039, the SEM Committee recognised that further discussion on the locational issue was required, and some further auction design decision were deferred pending resolution of the locational issues.

3.2.3 In the CRM Locational Issues consultation paper (SEM-16-052) the SEM Committee set out 5 auction format options (A to E). The auction formats suitable for adapting to the inclusion of transmission constraints[11] were:

- Option B: Simple sealed bid, with capacity secured to meet constraints being additional;
- Option C: Simple sealed bid, but with a "heuristic-based" second step which applies some rules to reduce capacity secured in surplus capacity regions to offset additional capacity secured to meet locational constraints, while at the same time addressing the lumpiness issue; and

[11] Options A and E did not reflect transmission constraints within the auction, so were not considered further for the T-1 auction

- Option D: Full combinatorial. This option would find the optimal combination of bids to accept, subject to the locational capacity delivery and bid inflexibility constraints.

3.2.4 In the decision paper (SEM-16-081) the SEM Committee decided to:

- As a transitional measure: Implement Auction Format Option B in preference to Auction Format Option C. The key difference between Option C and Option B is that Option C does not result in the procurement of additional volumes for transmission constraints. Instead, Option C would employ a heuristic approach to determining which units, of those in-merit on an all-island basis, should be displaced by out-of-merit "constrained on" capacity.
- As an enduring solution: Implement Auction Format Option D, which could include the representation of locational constraints, if required. Option D, like Option C, would not procure additional volumes in respect of constraints, but would find the optimal Net Social Welfare combination that met the all-island Capacity Requirement and locational constraints.

3.2.5 These decisions on auction format were combined with a number of other policy decisions made in SEM-16-081 and developed into drafting in the Capacity Market Code (CMC). The detailed drafting was further discussed via the Market Rules Working Group and consulted with the rest of the CMC in SEM-17-004.

3.2.6 Prior to the auction systems being capable of handling full combinatorial optimisation (i.e. a move to Option D), the CMC allows the System Operators to implement a simpler Alternative Auction Solution Methodology (AASM), as set out in section M.6. of the CMC. Such an AASM may reduce the range of combinations of inflexible price-quantity pairs considered in seeking a solution and may exclude exploration of combinations of solutions that are likely to be inferior to others. Any AASM has to comply with the principles set out in M.6.1.7.The AASM is proposed by the System Operators and approved by the RAs. The details of the methodology are then published with the Final Auction Information Pack for the relevant auction.

CY2018/19 Alternative Auction Solution Methodology (AASM)

3.2.7 The policy decisions taken to manage lumpiness require the auction system to solve a limited combinatorial problem, even within the context of Auction Format Option B which applied to the CY 2018/19 auction.

3.2.8 An AASM was approved for use in the first Capacity Auction (CY2018/19) and details of this solution were published on 1 December 2017 as part of the Final Auction Information Pack. To manage the size of the problem, this AASM placed a limit on the number of inflexible offers, N above the "base solution" which can be considered as part of the optimisation problem. For CY2018/19, N was set equal to five. Therefore, to solve the lumpiness issue, the solution was required to consider combinations of the marginal offer (if inflexible) and the five inflexible offers above the marginal offer, plus flexible offers not already cleared. The auction system solved well within the maximum allowed timeframe of 24 hours.

Illustrative worked example of CY2018/19 format

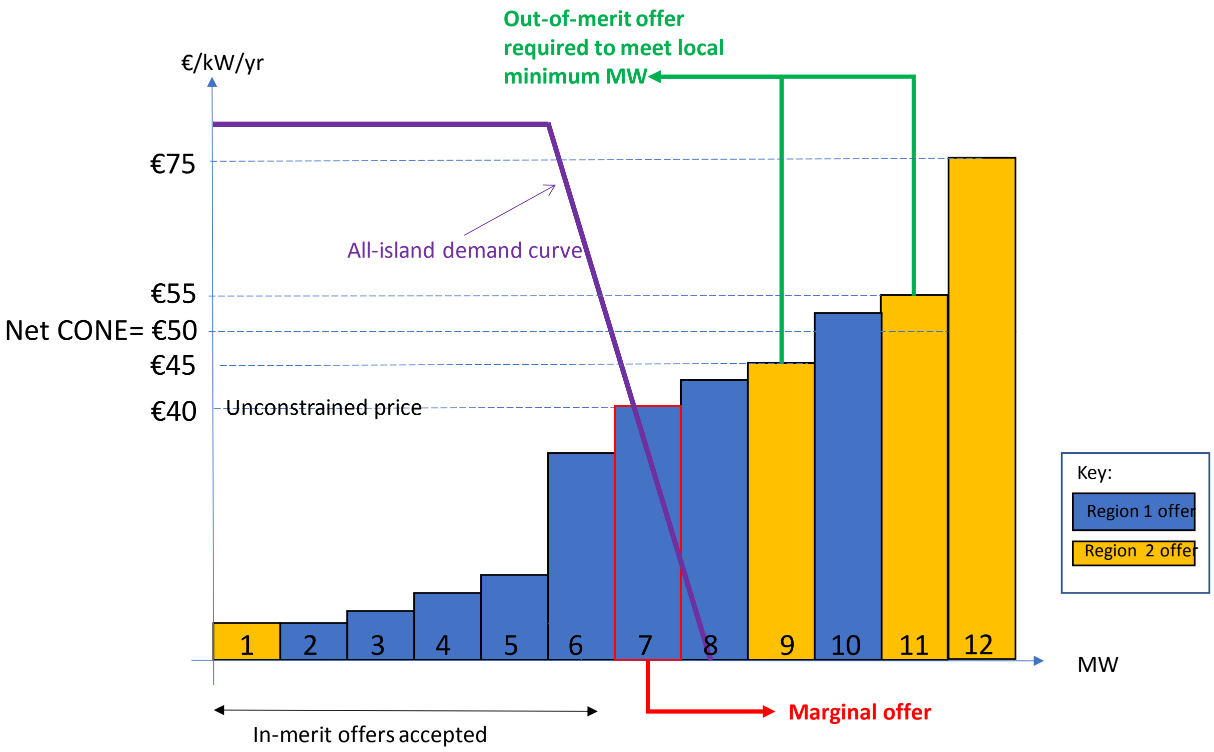
3.2.9 The key elements of the CY2018/19 and CY2019/20 T-1 auction design are illustrated by reference to a worked example in Figure 2 and described below. Figure 2, is a highly simplified example, in which we assume that:

- The all-island Capacity Requirement is 500MW, with the demand curve, which is shown in purple, crossing the MW axis at 750MW[12];
- There are only 2 areas (or Regions). Both Regions are assumed to have a minimum requirement of 300MW.

3.2.10 There were 12 offers, and all 12 offers are assumed to be:

- 100MW inflexible offers, so that only 100MW or 0MW of the offer can be accepted, but nothing in between; and
- For only a single-year Reliability Option.

Figure 2: High-level illustration of CY2018/19 and CY2019/20 T-1 approach



3.2.11 At a high level, winner and price determination worked as follows in the CY2018/19 T-1 auction:

- First, the auction system ranks offers in price order[13] to create an all-island supply curve, making no distinctions on the basis of area (i.e. creates the unconstrained schedule, alternatively referred to as the unconstrained merit-order).

[12] i.e. has a zero-crossing point of 750MW
[13] With further detailed tie-break rules to apply in the case of offers having the same price

- The clearing price is determined as the unconstrained price, the price of the marginal offer in the unconstrained schedule. The marginal offer is the offer at the point on the supply curve where it intersect the demand curve[14], which in this example is in Offer 7. The clearing price is €40/kW/yr;
- All offers below the marginal offer, i.e. those offers which are "in-merit" in the unconstrained schedule, in this case Offers 1 to 6, have to be accepted (or alternatively, this is sometimes referred to as "cleared"). <u>In CY2018/19, Offers 1 to 6 would be accepted, regardless of what other offers are required to meet the minimum MW required in any given Region.</u>
- Offers which are ranked after the marginal offer in the unconstrained schedule, are typically referred to as "out-of-merit" offers. In this example, Offers 8 to 12 are "out-of-merit";
- Offer 7, the marginal offer may be accepted or rejected depending on whether it increases or decreases Net Social Welfare, in combination with any "out-of-merit" offers accepted for transmission constraint or lumpiness reasons. Whether Offer 7 is accepted or rejected on Net Social Welfare grounds, it still sets the clearing price;
- The auction system then checks whether each of the minimum MW constraints in Regions 1 and 2 are met. In this example, it finds that Offers 2 to 6 more than meet the minimum MW in Region 1. However, it finds that there is only 100MW of Region 2 capacity in-merit in the unconstrained schedule, 200MW short of the minimum requirement in Region 2.
- The auction system seeks to find the feasible combinations of marginal and out-of-merit offers in Region 2, which together with the in-merit offers meet the minimum MW requirement. In this example, any combination of 3 of the Region 2 offers 1, 9, 11 and 12, or all four offers meet the minimum requirement, but Offer 1 must be accepted because it is in-merit. The auction system then applies the AASM to identify which of those allowed combinations optimises Net Social Welfare, subject to inflexibility constraints[15], and limits the number of inflexible offers that can be considered.

3.2.12 In the above simplified example, the auction format would result in:

- Offers 1 to 6 being accepted as they are in-merit in the unconstrained schedule, and paid-as-clear at €40/kW/yr;
- Offers 9 and 11 being accepted as out-of-merit generation to meet the minimum MW requirement in Region 2, in preference to Option 12, since they deliver a higher Net Social Welfare[16]. Offer 9 is paid-as-bid at €45/kW/yr, and Offer 11 is paid-as-bid at €55/kW/yr;

[14] If the curves intersect on a vertical segment of the supply curve, the clearing price is the price of the lower offer

[15] Where a capacity provider, bids inflexible, i.e. states that it is not prepared to have any number of MWs of its offer accepted between x MWs and y MWs.

[16] Offers 9 and 11 are accepted along with Offer 1 because they deliver a higher Net Social Welfare than any combination that includes Offer 12, which is 100MW inflexible like all other offers, but is more expensive than other offers. However, if Offer 9,11 and 12 had been a different MW volume to some of the offers, Offer 12

- Offer 7 is rejected. Since Offers 9 and 11 have to be accepted to meet the minimum MW constraint in Region 2, a minimum of 800MW have to be accepted[17] on an all-island basis. Since the demand curve cuts the axis at 750MW, incremental volumes above 750MW are deemed to have no value to consumers. Incremental acceptance of Offer 7 would have a producer cost[18], but no consumer value, so reduces Net Social Welfare.

3.2.13 As described above, in-merit offers in over-supplied regions, such as Offer 6, must be accepted as well as out-of-merit offers in under-supplied regions, and could not be displaced by out-of-merit offers.

3.2.14 In CY2018/19, this auction format (i.e. Option B) resulted in 525MW being procured out-of-merit[19] for constraint reasons, with that volume being additional to all in-merit offers.

3.3 CHANGE TO GIVE EFFECT TO STATE AID DECISION

3.3.1 The auction format used in the CY2018/19 T-1 auction has to be modified to make it applicable for use in CY2022/23 T-4 auction, since it is not consistent with the State aid decision commitment, not to procure additional capacity from CY2020/21 onwards. The design for the CY2022/23 auction must facilitate the displacement of some in-merit offers such as Offer 6 (and possibly other offers deeper in-merit), if additional out-of-merit volumes are to be procured to meet transmission constraints. Changes need to be made to the auction system and to the Capacity Market Code to accommodate the undertakings.

3.3.2 The intention remains that the enduring solution is to be based on Auction Format Option D (full combinatorial), but the TSOs are not yet ready to progress to Option D. In practice, Option D can only be used once the TSOs have completed the build and test of a Mixed Integer Linear Programme (MILP) solver, which can solve the full combinatorial problem within a reasonable timeframe. We have consulted with the TSOs, and they have indicated that they cannot be confident of implementing Option D in time for an auction in March 2019. Therefore, on grounds of practicality, we will need to implement a version of Option C for the CY2022/23 T-4 auction.

3.3.3 The CRM Locational Issues consultation or decision (SEM-16-081) did not specify what the Option C heuristic format would be, nor how it would select which in-merit units will be displaced by any out-of-merit units. Besides being State aid compliant, the solution needs to balance the following objectives:

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could have been accepted as a better solution to the inflexibility problem than Offers 9 and 11, despite being more expensive

[17] i.e. Offers 1 to 6, which are in-merit, and Offer 9 and Offer 11

[18] Deemed equal to its offer price

[19] Although this may slightly over-estimate the level of over-procurement as a different solution to the lumpiness problem would have resulted if the additional out-of-merit volume had not been procured.

- Be practically deliverable in terms of auction system changes by March 2019;
- Be likely to deliver a solution which is most consistent with the enduring solution, which will optimise Net Social Welfare.

3.3.4 The solution which is most consistent with a transition to the enduring solution (Option D), is to extend the range of combinations to include displacement of offers such as Offers 2 to 6 in Figure 2. Clearly the solution must continue to ensure that the minimum MWs are purchased in Region 1. However, only 3 of Offers 2 to 6 are necessary to meet the minimum MWs in Region 1. Up to two of the offers could be displaced by Offers 9 and 11, if that combination delivered a higher Net Social Welfare, measured against the all-island demand curve.

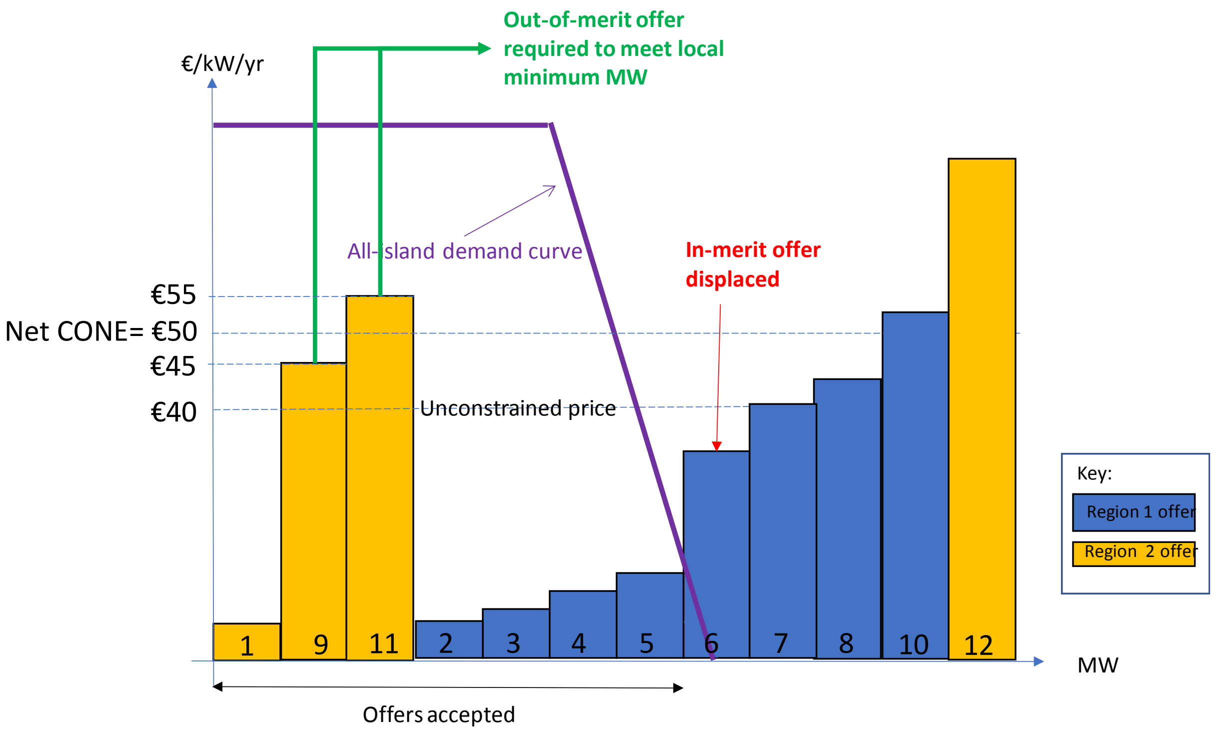
3.3.5 Under the proposed new Option C heuristic format, the auction system will have to solve the combinatorial problem for both lumpiness and displacement of the optimum combination of displacement of in-merit offers.

3.3.6 The example in Figure 2, is a highly simplified example with only 12 offers, compared with the 127 offers actually submitted in the CY2018/19 T-1 auction, so in the worked example, the solutions are much easier to identify. Applying the Option C heuristic to such a simple worked example will deliver the same results as applying Option D, but the purpose of this worked example is to illustrate the difference between the CY2018/19 approach and the CY2022/23 approach.

3.3.7 Figure 3 illustrates the optimal solution applying the Option C heuristic to example in Figure 2. In the optimal solution:

- Only Offer 6 of those in-merit in the unconstrained schedule is displaced;
- A total of 700MW is awarded, compared to the 800MW that would have awarded under the CY2018/19 auction format;
- Offer 5, whilst not necessary to meet the minimum MWs in Region 1 continues to be procured because the sloping demand still allows more volume to be procured if it is cheap;
- Offers 1 to 5 are still paid-as-clear, and the clearing price remains €40/kW/yr;
- Offers 9 and 11 are still paid at their respective bid prices of €45/kW/yr and €55/kW/yr respectively.

Figure 3: Optimal solution applying Option C heuristic



3.3.8 As in the CY2018/19, in a "real-world" example with, say, 127 offers instead of 12, the auction system needs to limit the size of the combinatorial problem. The TSOs have proposed an updated AASM which limits the size of the combinatorial problem. As before, the TSOs have specified a parameter N, which limits the size of the combinatorial problem, but whereas previous the specification of the N parameter only allowed consideration of whether to accept/reject the marginal inflexible offer and the N inflexible offers above the marginal inflexible offer, the revised specification would allow the auction system to consider whether to accept/reject the N inflexible offers above and the N offers below the marginal inflexible offer.

3.3.9 The TSOs will propose a value for N closer to the auction, following further systems development and testing, with that number to be approved by the SEM Committee and published in the Final Auction Information Pack.

3.3.10 The TSOs proposals for the updated AASM which defines the detail of the heuristic auction format (Option C) are set out in Appendix A. The TSOs' proposals are a development of the AASM employed in the CY2018/19 T-1 auction.

3.3.11 The RAs have reviewed the TSOs proposals and are broadly supportive of them, but have requested the TSOs engage in discussions with the auction system vendors to see whether it will be possible to specify two separate N parameters (N1 for the number of offers below the base solution and N2 for the number of offers above the base solution). Such an approach will allow more flexibility whilst still limiting the size of the combinatorial problem, if for instance a significant number of offers below the base solution must be excluded to allow for offers needed to secure sufficient capacity within the locational capacity areas.

3.3.12 We now seek feedback on the proposed changes to the auction design including the proposed AASM and the proposed CMC changes.

3.3.13 Note that the transitional T-1 auction for CY2019/20 can and will procure additional volumes in respect of locational capacity constraints, and will be based upon Auction Format Option B, like the CY2018/19 auction. This means that the Capacity Market Code will need to support one auction format in respect to the CY2019/20 T-1 auction to be held in December 2018, and a different auction format in respect the CY2022/23 T-4 auction to be held in March 2019.

3.4 SUMMARY OF CHANGES TO AUCTION FORMAT TO ACCOMMODATE MULTI-YEAR PAY-AS-BID RELIABILITY OPTIONS

3.4.1 In the simplified example in Figure 2, we assumed that all Offers were single-year offers. Suppose instead, that Offer 9 had met the threshold for the New Capacity Investment Rate Threshold (NCIRT- see Section 9) and specified the requirement for a multi-year pay-as-bid Reliability Option.

3.4.2 In the CY2018/19 auction, it would have been rejected because:

- Its offer price, at €45/kW/yr was higher than the unconstrained price; and
- The minimum MW requirement of 300MW in Region 2, could be met with a combination of Offers 1, 11 and 12.

3.4.3 The auction system currently has an additional check, after determining the unconstrained price, to check whether any out-of-merit offers are for 2 or more years[20]. Any out-of-merit offers that are for 2 or more years are not considered to meet the minimum MW in an under-supplied area, or to help solve the lumpiness issue, unless there is no other way to meet the minimum MW in an under-supplied area.

3.4.4 Therefore, in this revised worked example, applying the CY2018/19 auction approach would have resulted in:

- Offers 1 to 6 being paid the unconstrained offer price of €40/kW/yr as before;
- Offer 11 being paid its offer price of €55/kW/yr and offer 12 being paid its offer price of €75/kW/yr;
- All other offers, including Offer 9 being rejected.

3.4.5 Applying Option 2 as proposed in Section 2.2, the CY2022/23 approach to allow out-of-merit offers that are for up to 10 years to be considered to meet the minimum MW in an under-supplied area (including the move to comply with the State aid decision set out in Section 3.3) to the revised worked example would result in:

- No difference to Offers 1 to 5, which would be paid the same unconstrained price of €40/kW/yr for 1 year;

[20] Offers must be for an integer number of years between 1 and 10

- Offer 9 being paid-as-bid at €45/kW/yr for 10 years, since it price is less than Net CONE of €50/kW/yr;
- Offer 11 being paid-as-bid at €55/kW/yr for 1 year
- Offer 6 being displaced by Offers 9 and 11, just as in the example illustrated in Figure 3, to comply with the State aid commitment.
- All other offers also being rejected.

3.4.6 Applying Option 2 as proposed in Section 2.2, whilst keeping the price determination unchanged, would make the winner determination decision rules slightly more complicated:

- As described in Section 2.2, a multi-year pay-as-bid Reliability Option could be accepted in preference to a more expensive single year offer at any price up to Net CONE, i.e. €50/kW/yr in Figure 2;
- But as before, a multi-year offer could only be considered (purely) for lumpiness reasons if it was priced at or below the unconstrained clearing price, i.e. €40/kW/yr in Figure 2.

3.4.7 As discussed in Section 2.2, the benefits of accepting a multi-year pay-as-bid Reliability Option in preference to another more expensive offer in the same under-supplied area are potentially significant. The gains are more likely to be significant if there are barriers to entry which limit offers in the under-supplied area which can be used to solve the transmission constraint.

3.4.8 The reason why a multi-year Reliability Option would not be accepted up to a price of Net CONE for lumpiness reasons, is that lumpiness is an all-island optimisation, not a locational one. It does not appear to be in consumers' interests to commit to an out-of-merit multi-year pay-as-bid Reliability Option purely for a lumpiness reason. In the absence of a different rule for lumpiness, consumers could be committed to a multi-year pay-as-bid Reliability Option on the basis of the solution delivering a better Net Social Welfare solution to the lumpiness problem in the first year only. Next year, the optimum lumpiness solution is quite likely to be different. Whilst the same is true in principle for solving transmission constraint, it appears more likely that the risk of stranding is higher for out-of-merit lumpiness solutions.

3.5 SUMMARY OF CONSULTATION QUESTIONS

3.5.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you have any comments on the SEM Committee's proposal to move to an auction format based on Auction Format C for the CY2022/23 T-4 auction, following the State aid decision?

2) Do you have any comments on the TSOs proposed AASM for implementing the new auction format, as set out in Appendix A, or the RAs' proposed change to the N parameter?

3) Do you have any comment on the proposed change to the format to accommodate multi-year pay-as-bid Reliability Options?

4. CAPACITY REQUIREMENT

4.1 INTRODUCTION

4.1.1 The Capacity Requirement (CR) is a key input into the Auction Demand Curve. The CR is determined by the TSOs, based upon policy decisions and a methodology approved by the SEM Committee. The two key policy decisions taken by the SEM Committee were:

- The Loss of Load Expectation (LOLE) standard; and
- Whether to include reserves in the CR.

4.1.2 In CRM Decision 1 (SEM-15-103), the SEM Committee decided to retain the existing (8-hour LOLE) all-island security standard, rejecting alternatives such as a move to the 3-hour standard used in GB. In making this decision, the SEM Committee noted that "*this decision does not preclude the SEM Committee considering changes to the security standard at a later date – based on the information available at that time*".

4.1.3 In addition, in Capacity Requirement and De-rating Factor decision (SEM-16-082), we considered whether a proportion of the operating reserve requirement, which is typically in the range 400-500MW, should be added to the CR. In SEM-16-082, the SEM Committee foresaw that a number of elements of the design of the transitional auctions were likely to lead to a conservative approach to capacity procurement, including:

- The decision to procure additional capacity in respect of transmission constraints;
- The use of the CY2021/22 demand forecast to calculate the CR for all transitional years;
- The use of the Least Worst Regrets (LWR) approach, which tends to select higher demand scenarios as the basis for determining the CR; and
- The sloping demand curve, coupled with the excess of existing capacity, which allows up to 15% in excess of the CR to be procured, if offered cheaply. With the current excess capacity, it was recognised that the sloping demand curve was likely to result in capacity procurement in excess of the CR during the transitional period.

4.1.4 Therefore, in SEM-16-082 the SEM Committee decided that:

- Operating reserve will not initially be included in the CR;
- The decision on inclusion of reserve within the CR, will await further evidence from the TSOs supporting the need for such inclusion; and
- To the extent reserve is included within the CR, its level and justification will form part of the broader CR consultation.

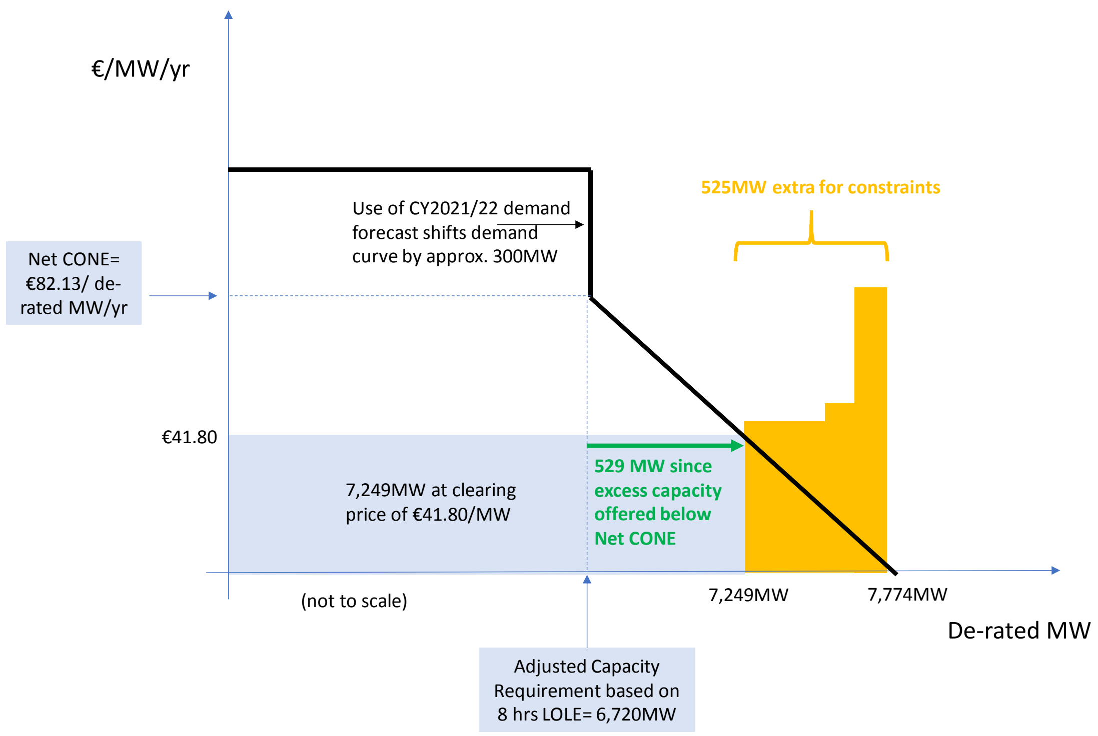
4.1.5 The decisions were vindicated by the results of the CY2018/19 transitional auction. As illustrated in Figure 4, in CY2018/19 a number of factors resulted in the award of over 1,054 de-rated MW of Reliability Options in excess of the adjusted[21] CR:

[21] Taking account of the capacity contribution of non-participating wind

- An additional 525 de-rated MW of Reliability Option in CY2018/19 were procured to meet the locational capacity constraint minimum requirement. However, as discussed in Section 2, the State aid decision means that from CY2020/21 onwards, we will no longer be procuring additional capacity in respect of transmission constraints, subject to meeting the Level 1 and Level 2 minimum requirements[22];
- The sloping demand curve, combined with the excess of low cost[23] existing capacity resulted in procuring 529MW of de-rated capacity. However, as existing capacity ages and responds to exit signals for old inefficient plant, this reduces the likelihood of procuring additional capacity at lower costs along the sloping demand curve by CY2022/23.

4.1.6 Additionally, the CY2018/19 Capacity Requirement was based on the demand forecast for CY2021/22. The high demand scenario forecast for the All-Island TER peak for 2022 was 390 MW higher than the median demand forecast for the All-Island TER peak for 2022. The LWR scenario selected was between the median and high scenarios, and the use of the a relatively high case CY2021/22 demand forecast for CY2018/19, inflated the CY2018/19 CR by approximately 300MW, in addition to the 1,054MW of capacity procured in excess of the CR.

Figure 4: Capacity in excess of 8-hour standard, CY2018/19



[22] In CY2018/19, the minimum MW requirement for Ireland was 5,260MW and the minimum requirement for Northern Ireland was 1,630MW. This exceeds the All-island adjusted CR of 6,720MW by 170MW.
[23] generation with Net Going Forward Costs (NGFCs) below Net CONE

4.1.7 However, the changes that will take effect between CY2018/19 and CY2022/23 will reduce the supply-demand balance by at least 825MW[24], and may be by as much as 1,350MW:

- By CY2020/21, we will no longer be procuring additional capacity for transmission constraints (525 MW for CY 2018/19).
- The use of a future year demand forecast (applicable to the transitional auctions) is not relevant for this first T-4 auctions (300MW for CY 2018/19)[25].
- Some of the existing excess supply of capacity is likely to respond to exit signals, reducing the likelihood of procuring additional capacity in excess of the CR at lower costs along the sloping demand curve (530MW for CY 2018/19).

4.1.8 The SEM Committee are now consulting on potential changes to the CR methodology for CY2022/23, including whether to:

- Incorporate some or all of operating reserves in the CR, or alternatively
- Tighten the "theoretical" LOLE standard, which could have a similar practical effect. Tightening the LOLE standard means reducing the LOLE target, e.g. from 8-hours LOLE to 3-hours LOLE.

4.1.9 In addition to the factors discussed above, key reasons to review the CR methodology include:

- Since the key CR methodology decisions were made, the EC and ENTSO-E have been developing proposals such as those contained within the latest planned Energy Package that may lead to gradual convergence of approaches to determining the CR. Whilst the proposals are still in draft form, and do not entail complete harmonisation, the "direction of travel" is now clearer. We discuss this issue in Section 4.2;
- The TSOs have recently provided new evidence on how they will operate the system at times when available operating reserve is less than target levels. In practice this means that if the amount of capacity is based only on a "theoretical" 8-hour LOLE standard there will, in practice be more than an average of 8 hours of lost load. We discuss this issue in Section 4.3, along with options for the inclusion of some or all of the operating reserve requirement in the CR;

4.1.10 In Section 4.4 we discuss the possibility of tightening the LOLE standard, which has largely the same effect as adding a proportion of operating reserves to the CR. In Section 4.5 we evaluate the options against the I-SEM design criteria.

[24] Based on an estimated 525MW of pay-as-bid Reliability Options and 300MW due to using the CY2022/23 demand forecast instead of the CY2018/19

[25] the last year of the transitional period. The demand forecast for all transitional years is based on the CY2021/22 demand forecast. The CY2022/23 will be based on the CY2022/23 demand forecast.

4.2 HARMONISATION OF EC CAPACITY REQUIREMENTS

Recent Developments

4.2.1 The latest planned Energy Package[26] includes a proposed Energy Regulation[27] which contains drafting relevant to the longer term setting of the CR, the inclusion of operating reserves, the LOLE Security Standard, the cost of new entry and the Value of Lost Load for the ISEM. The current draft of this Regulation has been prepared for negotiation with the European Parliament during 2018.

4.2.2 In the draft Regulation, ENTSO-E are required to produce a draft methodology for a European resource adequacy assessment. This assessment will use a single model that can also be used for national assessments and will enable the determination of LOLE and Expected Unserved Energy (EUE). In the same timeframe, ENTSO-E will also produce a methodology for the determination of VoLL, the cost of new entry and the reliability standard. These methodologies will be consulted on by ENTSO-E before being formally proposed to ACER for approval.

4.2.3 For the purposes of this consultation we note the direction of travel within the EC in the latest proposals however recognise that they are subject to further consideration and any subsequent EC decision will likely impact future CRM auctions.

ENTSO-E Mid-term Adequacy Forecasts

4.2.4 In their 2017 Mid-term Adequacy Forecasts (MAF), in modelling the capacity required for capacity adequacy, ENTSO-E generally either add some measure of operating reserve requirement to peak demand (their preferred approach) or reduce the effective thermal generation capacity commensurately.

4.2.5 The ENTSO-E 2017 MAF assumes very different levels of reserve requirement between countries/zones in the ENTSO-E area, both in terms MWs as a percentage of peak demand. For Ireland, ENTSO-E incorporate an estimate of 187MW (3% of peak demand) of reserve requirement in their estimate of required capacity for Ireland, and 126MW (7% of peak demand) in Northern Ireland, totalling 313MW.

Latest benchmarking of EC Capacity Requirements

4.2.6 In CRM Decision 1 (SEM-15-103, published December 2015) we discussed some international approaches to setting the security standard, including the LOLE standard where relevant. Since the publication of SEM-15-103, ACER have published a more extensive benchmarking of security standards in their 2015 Market Monitoring Report (published Nov 2016). As illustrated in Figure 5, only 9 countries in the study have an explicit LOLE (or equivalent LOLP[28]) standard. Of the 9 countries, 5 have a tighter standard (less than 8 hours), 2 have the same

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[26] Typically referred to as the Clean Energy Package
[27] 2016/0379 (COD)
[28] Which can be turned into LOLE by multiplying by the number of hours in the year

standard and 1 has a more relaxed standard. The only market which the I-SEM is currently directly connected to, GB[29], has a tighter standard, at 3 hours LOLE. The other countries in the I-SEM Regional Security Co-ordination area, CORESO, that have an explicit LOLE standard are France and Belgium. Both these countries have a 3-hour LOLE standard.

Figure 5: International benchmarking of security standards

Country	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MA	NL	NO	PL	PT	RO	SE	SI	SK	UK
Reliability Standard	No	Yes	NS	No	NS	No	No	No	No	Yes	No	NS[a]	Yes	NS	Yes	NS2	No	No	NS	NS	No	No	No	No	Yes	NS	No	NS	No	Yes
RMM																														
CM										10%														9%						
EENS																														
EIR																														
LOLE (h/y)		3										3	2.4			8						4			8					3
LOLP (h/y)			13												8															
F&D of expected outages																														
Other	None					NS			NS											NS	NS[c]					NS				
Reliability problems reported in the last five years	No	No	No	No	No	NS	No	No	No	No	No	NS	NS	No	No	No	Yes[b]	No	No	No	No	No	No	Yes[d]	No	NS	No	No	No	No

Sources: ACER, CEER, Assessment of electricity generation adequacy in European countries, Staff Working Document accompanying the Interim Report of the Sector Inquiry on CMs and Pentalateral generation adequacy probabilistic assessment[31].

Note: a – Binding reliability standards may either already be in place or implemented in the future; b – Reliability problems have arisen on the Islands of Sardinia and Sicily, which are not well connected to mainland Italy; c – Generation adequacy assessment is based on a deterministic approach; and d – A heat wave during August 2015 caused emergency measures to be taken to meet demand. The figures in the table present the reliability standards within the metrics. NS: Not specified. RMM: Reserve Margin Method, CM: Capacity Margin, EENS: Expected Energy Not Supplied, EIR: Energy Index of Reliability, LOLE: Loss of Load Expectation, LOLP: Loss of Load Probability, F&D: frequency and duration of expected outages: a probabilistic risk measure, in terms of the tangible effects on electricity.

Source: Table 1, p32 of ACER Market Monitoring Report 2015-KEY INSIGHTS AND RECOMMENDATIONS, published 9/11/2016[30]

4.3 RESERVES AND THE CAPACITY REQUIREMENT

4.3.1 There are two key reasons why the SEM Committee may consider including an operating reserve requirement in the CR:

- Moves to harmonise the definition of the CR across the EC discussed above; and
- Suggestions that a "theoretical" 8-hour LOLE standard will not be achieved in practice, unless at least some proportion of the operating reserve requirement is included in the CR.

[29] Figure 5 shows the GB value as "UK". This standard does not apply to Northern Ireland.

[30] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20KEY%20INSIGHTS%20AND%20RECOMMENDATIONS.pdf

“Theoretical” 8-hour LOLE standard and operating reserves

4.3.2 The 8-hour LOLE standard is a key policy input into the CR methodology. In estimating the CR, the TSOs estimate the MW of capacity required to ensure that there are no more than 8 hours where there is expected to be insufficient available capacity to meet demand[31].

4.3.3 If there is insufficient available capacity to meet demand, involuntary load-shedding occurs. The 8-hour standard is therefore consistent with an expectation of 8-hours of involuntary load-shedding. In practice, the TSOs may engage in “demand control”, i.e. controlled load-shedding[32] in circumstance where they consider that it is highly likely that uncontrolled (involuntary load-shedding) will occur unless they undertake controlled load-shedding. In such circumstances, the TSOs may undertake “demand control”, because the consequences of “demand control” are less detrimental than uncontrolled load shedding.

4.3.4 The RAs understanding that in general “demand control” will be actioned when the level of available operating reserve falls below 100MW.

4.3.5 Therefore, whilst the CR current methodology will deliver a CR consistent with delivering a “theoretical” 8-hour LOLE standard, in practice, we would need to add 100MW to the CR to deliver an 8-hour standard in practice.

4.3.6 The TSOs’ operating policy requires them to hold a certain level of operating reserve. There are a number of factors which drive the level of operating reserve requirement, but typically the dominant factor is the size of the largest infeed. In SEM-16-082, we considered including up to 444MW in the CR as a proxy for the operating reserve requirement, based on the size of largest generating unit. In practice, the operating reserve may be as much as 500MW if the EWIC interconnector is importing at full capacity, as it may well be during scarcity events. If this approach had been applied in CY2018/19, the CR would have been 7,530 de-rated MW (instead of 7,030 de-rated MW) and the adjusted CR would have been 7,220 de-rated MW (instead of 6,720 de-rated MW).

4.3.7 However, adding the full 500MW of operating reserve would deliver a security standard much higher than 8 hours LOLE. The TSOs estimate that approximately 250MW of additional capacity would be added by moving from a “theoretical” 8-hour standard to a “theoretical” 3-hour standard. It is estimated that around 350MW would be required to move from a “theoretical” 8-hour standard to a “practical” 3-hour standard, taking into account a “minimum” operating reserve requirement of 100MW.

4.3.8 Partial Administered Scarcity Prices (ASP) apply when there is insufficient operating reserve to maintain the target operating reserve. Applying an 8-hour standard, without the addition of

[31] The approach uses a Least Worst Regrets approach, with multiple demand scenarios, and calculates the number of MWs required for an 8-hour standard in each scenario. The Capacity Requirement then corresponds to the MWs for the scenarios that has the Least Worst Regret costs (see SEM-15-103)

[32] It is important to note that there is a difference between demand side response and controlled load shedding. Demand response is where an end consumer has agreed to be part of a demand side response programme, and reduce load at times of system stress, typically in return for preferential commercial terms. Demand control actions are actions taken after demand side response options have been exhausted.

any operating reserve requirement may result in more hours of Partial Administrative Scarcity Pricing than the assumed 8 hour standard and 4 hours of partial ASP in the CRM Parameters decision (SEM-17-022). Adding 500MW of maximum operating reserve requirement to a "theoretical" 8-hour standard should, in theory, result in less than 8 hours of Full and Partial ASP in total, since the target operating reserve requirement is sometimes less than the maximum requirement of 500MW.

4.3.9 We are now considering the following options for the inclusion of operating reserve:

- Option 1: Include 100MW of operating reserve in the CR, consistent with the RAs understanding regarding TSOs "demand control", based on a minimum required operating reserve requirement. The inclusion of this level of reserve would be required for a "practical" 8-hour standard as opposed to the current "theoretical" 8-hour standard;
- Option 2: Include 250 MW, based on 50% of largest single infeed. This level of operating reserve is broadly equivalent to "theoretical" 3-hour LOLE standard;
- Option 3: Include 313 MW, based on the sum of the ENTSO-E estimate of requirements for Ireland and Northern Ireland included in the 2017 ENTSO-E Mid-term Adequacy Forecast;
- Option 4: Include 444 MW, based on largest generating unit as referenced in SEM-16-082. This is likely to be the operating reserve requirement at times when EWIC is not importing close to full capacity; and
- Option 5: Include 500 MW, the maximum target operating reserve requirement, which applies when the largest single infeed EWIC is importing at full capacity.

4.4 LOLE STANDARD

4.4.1 EC moves to harmonise CR methodologies may also eventually result in the harmonisation of other elements of the approach to CR estimation, including the choice of LOLE standard. Based on the benchmarking data presented in Figure 5, the most likely options, if there is any standardisation are:

- Option A: an 8-hour standard; and
- Option B: a 3-hour standard.

4.4.2 The I-SEM 8-hour standard, whilst by no means an outlier on an EC wide basis, is generally not as tight as most markets in the same regional co-ordination zone (CORESO). GB, Belgium and France, which are the members of the CORESO zone with an explicit LOLE standard all employ a 3-hour standard.

4.4.3 We note that the inclusion of 250MW of operating reserve has a very similar practical effect as moving from a "theoretical" 8-hour standard to a "theoretical" 3-hour standard, so any moves to incorporate operating reserve should be considered in conjunction with the potential harmonisation of an LOLE or equivalent standard.

4.5 EVALUATION OF I-SEM DESIGN CRITERIA

4.5.1 We have evaluated the implications of the different options for including operating reserve / LOLE standard below. Broadly speaking, the impact of the change is directly related to the change to the CR.

4.5.2 The key impacts against relevant I-SEM criteria are discussed below.

Internal market

4.5.3 There is no EC internal market standard, as yet. However:

- The direction of travel appears to be to include a proportion of operating reserves in the CR.
- As illustrated in Figure 5, the I-SEM LOLE standard whilst not in the tightest 50%tile is by no means an outlier. However, the only market to which the I-SEM is physically connected has a 3-hour standard, and other members of the same Regional Security Co-ordination zone, have an explicit standard use a 3-hour standard.

System security

4.5.4 The RAs current understanding is that the inclusion of around 100MW of operating reserves in the CR is necessary to ensure that an 8-hour LOLE standard is delivered in practice, and is not just a "theoretical" standard.

4.5.5 Clearly including more operating reserve requirement or tightening the LOLE security standard, say from 8-hours LOLE to 3-hours LOLE improves system security. Note that including 50% of the maximum operating reserve requirement or tightening the LOLE standard from 8-hours to 3-hours have the same practical effect at an all-island level

Competition

4.5.6 In CY 2018/19, with significant capacity in excess of the CR, unreliable plant did not price the risk of uncovered Reliability Option Difference Payments (RODP) into their CRM offers. Uncovered RODPs are RODPs, which are not matched by corresponding energy income, as a result of a forced outage at times of scarcity. By CY2022/23, it would be prudent to assume that by CY2022/23, plant will have responded to exit signals over multiple years, and we will be nearing the CR[33]. By CY2022/23 we can expect that:

- Unreliable plant will seek to price a bigger risk of uncovered RODPs into the CRM offers than reliable plant; and
- The risk of uncovered RODPs is greater under an 8 hour standard than a 3 hour standard, as there are more scarcity events associated with an 8 hour standard, hence more risk of uncovered RODPs.

4.5.7 Therefore, a move from an 8-hour standard to a 3-hour standard may mean weaker exit signals for unreliable plant.

[33] Although we will continue to deploy a sloping demand curve

Equity and stability

4.5.8 The key impacts on equity and stability relate to how increasing the CR affects the level and volatility of energy and capacity prices.

4.5.9 Inclusion of operating reserves or tightening the LOLE standard may result in:

- Fewer high energy price events, resulting in lower energy price levels and lower price volatility for capacity providers and Suppliers. However, some of the effects of high and volatile energy prices will be mitigated by the effect of the Reliability Option anyway;
- Complex effects on capacity providers' CRM offer prices, which could increase the offer prices of some capacity providers and reduce the offer prices of others (see discussion below). Under certain scenarios, increasing the CR could lower offer prices, and materially lower the supply curve.

4.5.10 For a unit which is reliable (has a low outage rate), a tighter capacity standard is likely to reduce its IMR, as there are fewer high energy price scarcity events. For some capacity providers the reduced IMR is likely to result in higher CRM offer prices. Therefore, it may be that tightening the CR may result in a larger volume of Reliability Options and higher offer prices, increasing the cost of the CRM to consumers. However, there are circumstances under which tightening the CR may reduce CRM offer prices, partially or fully offsetting the effect of having an increased capacity requirement, with the potential to reduce the CRM bill to consumers.

4.5.11 However, we may also wish to consider the impact on reliable capacity providers which do not have "missing money". Any capacity provider without "missing money" will want to ensure that its Reliability Option fee at least covers its expected Reliability Option Difference Payments (RODPs), so that it does not lose money as a result of CRM participation. Inclusion of operating reserves in the CR or the tightening of the LOLE standard, is likely to reduce RODPs by reducing the frequency of high energy price scarcity events. Therefore it reduces the opportunity cost of a Reliability Option, and may reduce its CRM offer price.

4.5.12 For an unreliable unit, a tighter capacity standard may reduce its CRM offer price, as it reduces the risk of exposure to uncovered RODPs- high energy price scarcity events which trigger RODPs but are not covered by offsetting income[34].

Efficiency

4.5.13 An efficient level of investment occurs when the incremental cost to the consumer of new capacity is equal to the incremental reduction in the cost of Expected Unserved Energy (EUE). Typically, the incremental cost of capacity is assumed to be BNE Net CONE, and is assumed to be exogenous – independent of the CR. EUE is typically valued at VoLL[35].

4.5.14 We note that ensuring that we have the target operating reserve does not have value *per se*, if it does not translate directly into reduction in EUE. As discussed above, if the available

[34] Exposure to uncovered RODPs are capped by stop-loss limits, but an unreliable generator can still lose money

[35] VoLL x change in MWh of EUE

operating reserve falls below 100MW in practice, it results in "demand control" actions, and hence an increase in EUE.

4.5.15 During the CRM detailed design phase, we took the BNE Net CONE to be exogenous, and was assumed to be €82.13/de-rated kW in CY2018/19. However, in calculating the point at which the incremental cost of capacity is equal to the incremental EUE saving we should take into account the following:

- We are currently consulting on updating our estimate of I-SEM CY2022/23 BNE Net CONE (SEM-18-025); and
- The BNE Net CONE value may itself be affected by the security standard, particularly if higher levels of ASP make IMR estimates more sensitive to the CR;

Environmental

4.5.16 Tightening the security standard would reduce the reward to non-CRM participating renewables, whose net energy market income is not capped by RODPs. Non-participating renewables will have fewer instances where they earn prices above €500/MWh if the security standard is tightened. However, tightening the security standard reduces the risk for intermittent renewables to participate in the CRM.

Practicality

4.5.17 Adjusting the capacity requirement by including operating reserves or tightening the LOLE standard could reduce energy price volatility and risk for capacity providers enhancing participation.

4.6 SUMMARY OF CONSULTATION QUESTIONS

4.6.1 The SEM Committee seeks consultation feedback on the evidence and options presented in this Section and in particular:

1) What are your views on the potential changes proposed to the CR methodology i.e:

- Incorporate some measure of operating reserves in the CR? What MW value?
- Whether the 8-hours LOLE standard should be tightened (reducing the LOLE target). What level do you consider to be appropriate and why?

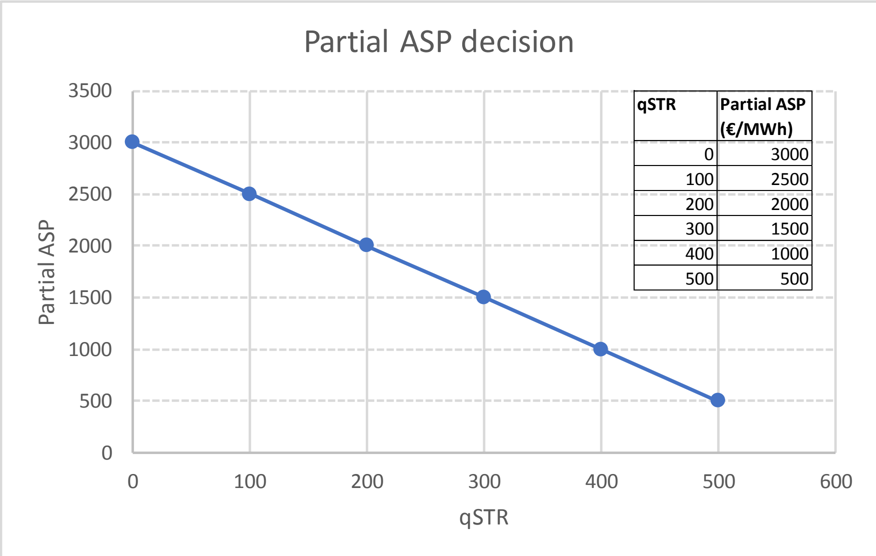
5. ADMINISTERED SCARCITY PRICING PARAMETERS

5.1 INTRODUCTION

5.1.1 During the CRM Detailed Design phase, the SEM Committee decided that, for the transitional period (to the end of CY2021/22):

- The value of the Full Administered Scarcity Price (Full ASP) would be set at the Euphemia day ahead price cap of €3,000/MWh; and
- The Partial ASP function would be as illustrated in Figure 6.

Figure 6: Administrative Scarcity Price as function of available operating reserve (qSTR)



5.1.2 The ASP function sets a floor on the BM price when a scarcity event occurs, it is not a price cap. Thus, at the current time, if a scarcity event occurs at a time when the remaining available reserve is only 200MW, then the BM price will be the higher of the ASP function price (€2,000/MWh) or a market determined price[36]. The market determined price can rise as high as VoLL[37], set at €11,128.26/MWh in 2018[38].

5.1.3 The SEM Committee stated that:

- The above ASP function will apply throughout the transition period, after which it will be based on VoLL; and

[36] Therefore, for instance, if the TSOs accept an offer of €2,500/MWh (for energy reasons), the accepted offer price of €2,500/MWh will set the BM price since it is higher than the ASP function value.

[37] In the I-SEM Policy Parameters and Scheduling and Dispatch Parameters Decision Paper (SEM-17-046), published in July 2017, the SEM Committee decided to set PCAP at VoLL. PCAP will set the maximum price in the I-SEM Balancing Mechanism (BM). The fact that PCAP will be set to VoLL means that prices may rise to VoLL if market participants place energy offers at that price, and those offers are accepted either by other market participants, or by the TSOs. However, administrative scarcity alone will not drive BM prices above €3,000/MWh during the transitional period.

[38] SEM VoLL was originally set at €10,000/MWh for the period from 1st November 2007 to 31st December 2008, and updated annually since based on inflation indexation, with a 2/3 weighing for Ireland HICP and 1/3 weighting for UK CPI

- 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.

5.1.4 The policies set out in CRM Decisions 1 and 2, have been implemented in the revised Trading and Settlement Code (TSC) published in April 2017 (SEM-17-024).

5.1.5 There were a number of factors which led the SEM Committee to set the transitional value of Full ASP to €3,000/MWh:

- It was recognised that the EUPHEMIA Day-Ahead price is currently capped at €3,000/MWh, and there was some concern that the prospect of a higher regulated BM price could lead generators to withhold power from the Day-Ahead Market (DAM), in order to benefit from potentially higher BM prices. Withholding of power from the DAM is clearly undesirable distortion and could lead to sub-optimal dispatch outcomes;
- To align with the GB approach. This decision was taken at a time when I-SEM go-live was scheduled for October 2017, and it was expected that the GB VoLL would be £3,000/MWh for the first winter of the I-SEM; and
- A desire to manage risk during the transitional period, including to small suppliers, particularly as this decision was made at a time before the arrangements for the Socialisation Fund had been fully developed.

5.1.6 The SEM Committee is now consulting at what percentage of VoLL the enduring value of Full ASP should be set at, since market participants will want to be able to factor in the value of Full ASP into their CY2022/23 T-4 auction offers[39].

5.2 CONTEXT

5.2.1 In arriving at the proposed options below we have considered the wider context particularly:

- Moves by the European Nominated Electricity Market Operators (NEMOs) and ACER to harmonise maximum Day-Ahead, Intra-Day and Balancing Mechanism prices.
- The planned evolution of GB VoLL, since the relative magnitude of GB and I-SEM VoLL may have a material impact on the direction of flows on the GB interconnectors at times of coincident scarcity; and
- The level of I-SEM VoLL and the way in which it will evolve.

5.2.2 The moves by the NEMOs and ACER to harmonise DAM, IDM and BM prices, clearly have the potential to impact the optimal solution for the value of Full and Partial ASP in the I-SEM for

[39] We note that whilst the SEM Committee will set intended values for Full ASP and the Partial ASP function for CY2022/23 in the decision document following this consultation, the SEM Committee cannot guarantee the 2022/23 values in 2018. As discussed below, maximum and minimum DAM, IDM and BM values are the subject of EU Harmonisation, and the SEM committee cannot preclude the requirement to change in response to European regulation.

CY2022/23. To the extent that the maximum DAM price of €3,000/MWh is increased following the ACER consultation, the value of Full ASP could be increased without triggering concerns that a higher ASP will distort incentives to trade in the DAM.

5.2.3 However, we note that:

- Whilst the direction of travel is clearly in the direction of higher maximum prices in spot markets, there are no firm proposals to set a maximum harmonised price for Balancing Markets at this time.
- If higher maximum DAM, IDM or BM price caps are set as a result of harmonised European regulation, it does not necessarily follow that I-SEM Full ASP has to be set at the same level as the price cap. As discussed above, the value of the ASP function is a price floor for the I-SEM BM, not a price cap. Thus, whilst the value of Full ASP cannot exceed any harmonised European cap on BM prices, the ASP price floor function could be lower than a harmonised cap.

5.2.4 The administered cash-out price in GB BM will move from £3,000/MWh to £6,000/MWh on 1 November 2018, in accordance with GB Balancing and Settlement Code Mod P305, approved by Ofgem on 2 April 2015.

5.2.5 If the GB BM administered scarcity price is higher than the I-SEM price administered scarcity price, it may appear more likely that power would flow from the I-SEM to GB at times of coincident scarcity. However:

- If the TSOs are prepared to pay more than the Full ASP for balancing energy, power could conceivably still flow into I-SEM from GB at times of coincident scarcity. Full ASP is a price floor, not a price cap, and the TSOs may accept BM offers in excess of Full ASP, which could serve to change the direction of power flows.
- It is not certain that in Balancing Market timescales, power flows will be entirely determined by prices. At times of scarcity, under current European codes[40], TSOs have the ability to reduce exports. Therefore, at times of coincident scarcity in balancing time scales, EirGrid/SONI and National Grid in GB may both be able to limit exports, so that prices cease to be relevant for incremental flows. However, the direction of travel of Internal Market harmonisation is to make cross-border flows increasingly price dependent, and at some future point in time, even balancing market flows may be fully price determined.

5.2.6 Therefore, whilst we should not ignore the effect of comparative GB and I-SEM administered scarcity prices on determining the direction of power flows during coincident scarcity, they are not necessarily the only determinant of the direction of flows.

[40] in particular Capacity Allocation and Congestion Management Regulation (CACM) (2015/1222) and the Regulation establishing guidelines on electricity transmission system operation (NCSO) (2017/1485)

Level of I-SEM VoLL

5.2.7 In SEM-17-071, the SEM Committee set the value of VoLL for calendar year 2018 at €11,128.26/MWh. Based on an assumption of 2% p.a. inflation, we might expect VoLL to be approximately €12,046/MWh in 2022 and €12,289/MWh in 2023.

5.2.8 There are no plans to undertake a fundamental review of I-SEM VoLL at this stage. In SEM-17-046, the SEM Committee specifically stated that, "*the SEM Committee does not agree that a review of VoLL is required at this stage*".

5.2.9 We do not preclude a complete review of VoLL prior to CY 2022/23, but for the purposes of calculating USPCs for the CY2022/23 T-4 auction to be held in Q3/Q4 2018, we will assume that there will not be a wholesale review of VoLL. We will project VoLL based on a 2% p.a. future inflation assumption.

5.2.10 We may consider moving to setting VoLL on an October to September year (as opposed to the current Calendar Year basis), so that the value of Full ASP does not change part way through a Capacity Year and seek feedback on that point as part of this Consultation.

5.3 OPTIONS AND OPTION EVALUATION

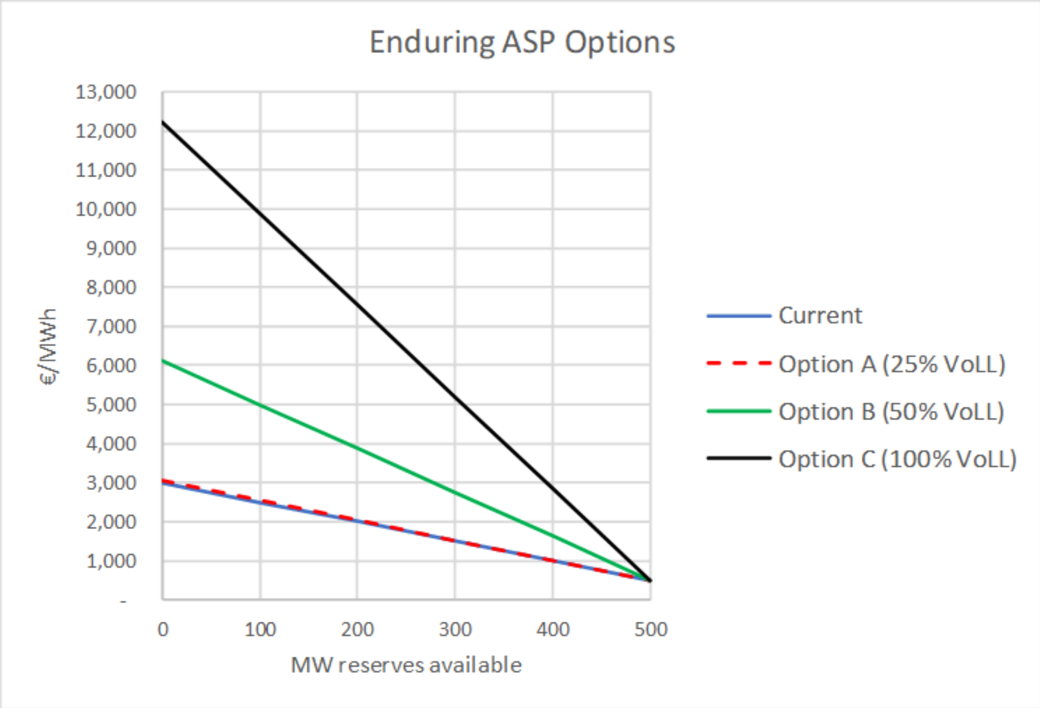
5.3.1 In this Section, we consider three options for the value of Full ASP following the transitional period (i.e. commencing at the start of CY2022/23) and evaluate them against the I-SEM Assessment Criteria:

- Option A: 25% of VoLL, likely to be around the current level of €3,000/MWh in CY2022/23, depending on inflation[41];
- Option B: Move to 50% of VoLL, expected to be approximately €6,000/MWh in CY2022/23; and
- Option C: Move to 100% of VoLL, expected to be around €12,000/MWh in CY2022/23.

5.3.2 These options are shown in Figure 7, which assumes that the Partial ASP function continues to be a straight line (one-piece linear) function, like the current (transitional) function. The one-piece linear partial ASP function was originally specified with reference to the LOLP data previously provided by the TSOs. We will need to review whether the one-piece linear function is still appropriate, particularly if a significant volume of operating reserve is included in the CR.

[41] As set out above, based on 2% p.a. inflation, VoLL would be €12,046/MWh in 2022 and €12,289/MWh in 2023, but we use the indicative value of €12,000/MWh

Figure 7: ASP function options



Factors determining the enduring ASP function value

5.3.3 Relevant factors which the SEM Committee will take into account in setting the enduring ASP function include:

- EC price harmonisation moves;
- Interconnector flows and system security
- Other economic efficiency considerations
- Impact on prices, consumer bills and capacity provider risk
- Socialisation fund and hole-in-the-hedge
- Sending exit signals to unreliable plant

EC price harmonisation

5.3.4 The value of Full ASP will need to take account of measures to harmonise prices at an EU level. As discussed above, moves to harmonise international DAM and IDM prices are ongoing, but there are no current plans to harmonise BM prices. It is clear that ACER and the EC favour increasing electricity spot prices and wish to allow prices to rise to levels that better reflect scarcity and VoLL. However, whilst higher harmonised DAM and IDM prices would facilitate a higher enduring Full ASP, it does not necessitate a higher Full ASP, since the ASP function sets minimum I-SEM prices, not maximum prices.

Interconnector flows and system security

5.3.5 The ASP function should promote efficient flows on the existing GB interconnectors and any future interconnectors to other countries. GB is setting its equivalent to Full ASP to £6,000/MWh from 1 November 2018, broadly equivalent to our Option B, although it depends on how inflation and exchange rates evolve. However, note that the GB "equivalent" Full ASP is a price cap, whereas the ISEM Full ASP is a price floor.

5.3.6 If we keep enduring Full ASP at around €3,000/MWh (Option A), it increases the likelihood of power flowing from the I-SEM to GB at times of coincident scarcity, reducing I-SEM system security. However:

- EirGrid/SONI may accept GB offers at prices in excess of I-SEM Full ASP, as well as accepting I-SEM offers at prices above Full ASP;
- As discussed above, it is not clear that prices will be the sole determinant of the direction of power flows in at times of coincident scarcity.

5.3.7 Higher ASP function options will also strongly promote system security, by ensuring that all I-SEM market participants will have strong incentives to be available (in the case of capacity providers) or to demand manage at times of system stress.

Economic efficiency

5.3.8 From an economic efficiency perspective, there are clear arguments in favour of setting the value of enduring Full ASP to 100% of VoLL (Option C), assuming VoLL is an accurate measure of the opportunity cost to affected consumers[42]. Capacity providers and Suppliers will face the marginal cost of their actions on consumers, although these incentive effects are blunted to some degree by the Reliability Option.

5.3.9 The partial ASP function should then reflect the value of VoLL and the Loss of Load Probability, as function of available MW reserves.

Impact on prices, consumer bills and capacity provider risk

5.3.10 If we increase the value of the ASP function, it is likely to:

- Increase the incidence of high energy prices, although Suppliers, and hence consumers will be protected against the energy price spikes by RODPs to a significant extent;
- Options with higher ASP values increase the risk to capacity providers. Whilst this effect is most pronounced with unreliable plant, to some extent it is likely to be true for all capacity;
- Increase consumer CRM bills. Higher ASPs can be expected to have an effect on some capacity providers' bidding behaviour, increasing their bids once the current excess of capacity has responded to exit signals.
    - For capacity providers without "missing money" at lower levels of ASP, it will increase the opportunity cost of the Reliability Option, increasing their CRM offers. If generators seek to incorporate the opportunity costs of RODPs in their auction offers, Option C could have a very material impact on CRM auction

[42] SEM-17-046 and its associated consultation document set out the reasons for setting PCAP to VoLL. The same arguments apply in respect of setting Full ASP to 100% of VoLL. If perceived or real constraints on bidding behaviour prevent prices rising to the opportunity cost of lost load (i.e. VoLL) then there is an efficiency argument for setting Full ASP at this level too

offers. In the CRM parameters decision (SEM-17-022), we assumed that the opportunity cost of RODPs could be around €24/kW/yr[43] if there were 8 hours of Full ASP priced at €3,000/MWh and 4 hours of partial scarcity priced at €1,500/MWh. However, with the same assumption about the number of hours of full and partial ASP, under Option C, the opportunity cost of RODPs would be €117.26/kW/yr[44];

- Option C, and to some extent Option B also increases the risk for unreliable plant. The key risk is that they are unavailable at times of scarcity and have to pay high RODPs without having corresponding energy income. This risk could also lead them to price increased risk into their CRM offer prices. Whilst exposure to this risk may send a desirable exit signal in the longer term, in the short term it could lead to high CRM prices until such plant is priced out of the market.

5.3.11 We note that for some capacity providers, higher ASPs may increase IMR, reduce "missing money" and lead to lower CRM offers. For reliable plant with "missing money" at current level of ASP, higher ASPs increases IMR, as the additional revenue from higher prices outweighs higher RODPs[45].

5.3.12 However, overall, moving to Option C could lead to significantly higher consumer CRM bills, as capacity providers seek to price increased opportunity cost and risk into their CRM offers.

Sending exit signals to unreliable plant

5.3.13 Higher ASPs sharpen the incentives to be available at times of scarcity, and make it more difficult for unreliable plant to compete. The financial consequences of being unavailable at times of scarcity are more serious, if energy prices are higher. To some extent, capacity providers are protected from unreliability by stop-loss limits, but these are a function of the CRM clearing prices. However, as discussed above, the CRM clearing price may be higher if ASPs are higher.

Socialisation fund and hole-in-the-hedge

5.3.14 Higher ASPs could also lead to a bigger "hole-in-the hedge"[46]. Higher energy income will be earned by non-participating capacity (e.g. opted-out intermittent renewables), which will increase the size of the hole-in-the-hedge, and potentially put more stress on the socialisation fund. Additionally, higher ASPs mean larger RODPs for participating capacity providers, which could increase the incidences of them hitting their stop-loss limits.

5.3.15 Therefore Option C, and to a lesser extent Option B potentially increase reliance on the Socialisation Fund to ensure stability, and could lead to more occurrences of "suspend and accrue".

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[43] Calculated as ((€3000/MWh - €500/MWh) x 8hrs +(€1,500/MWh - €500/MWh) x 4 hours) /1000

[44] Calculated as ((€12,226.27/MWh - €500/MWh) x 8hrs +(€6,363.14/MWh - €500/MWh) x 4 hours) /1000

[45] Their IMR is capped at the Reliability Option Strike Price (likely to be €500/MWh) on the capacity covered by a Reliability Option, so will not increase if the ASP function increases. However, capacity providers can earn the full ASP on their de-rated capacity, which is not subject to RODPs

[46] see SEM-15-103 for explanation of hole-in-the hedge

5.4 SUMMARY OF CONSULTATION QUESTIONS

5.4.1 The SEM Committee welcomes views on the following consultation questions:

1) Which of the options for the value of Full ASP do you consider most appropriate for the first T-4 capacity auction, and why?

2) Should we move to setting VoLL on an October to September year, rather than the current Calendar Year basis, so that a single value of VoLL pertains within a Capacity Year?

6. AUCTION VOLUMES AND DEMAND CURVE

6.1 INTRODUCTION

6.1.1 In CRM Decision 3 (SEM-16-039) the SEMC decided that the volumes procured in the T-4 auction will be determined by the SEM Committee and specified in the form of a demand curve.

6.1.2 In setting the demand curve parameters the SEM Committee will take account of the following:

- The Capacity Requirement (CR) to be estimated by the TSOs in accordance with the approved methodology set out in CRM Capacity Requirement and De-rating Methodology decision (SEM-16-082). This methodology may be subject to changes resulting from the consultation in Section 4 of this document;

- Volumes, if any, already procured in respect of the relevant Capacity Delivery Year under multi-year Reliability Options; and

- Volumes to be withheld from the T-4 auction to the T-1 auction for the same capacity year.

6.1.3 We will not have completed all the transitional T-1 auctions for CY2020/21 and CY2021/22 before the T-4 CY2022/23 auction. Therefore, when setting the demand curve for the CY2022/23 auction we will not know for sure whether any multi-year Reliability Options will be awarded in the CY2020/21 or CY2021/22 auctions. However, we propose to assume that no multi-year Reliability Options will be awarded in the remaining transitional T-1 auctions when setting the demand curve for the T-4 CY2022/23 auction. However, this does not preclude multi-year Reliability Options being awarded which cover CY2022/23 capacity in the remaining transitional auctions.

6.1.4 In this section we consult on:

- The proportion of the CR to withhold from the T-4 auction to the T-1 auction in the light of the high level of participation of demand side response in the first transitional T-1 auction;
- Whether to hold back volume from the Level 1 and Level 2 areas' minimum MW requirements, or just to withhold volume at an all-island level; and
- Whether to make any changes to the shape of the demand curve in the T-4 auction.

6.2 PROPORTION OF CAPACITY REQUIREMENT TO WITHHOLD FROM T-4 AUCTION

6.2.1 In CRM Decision 3 (SEM-16-039), the SEM Committee stated its intention to hold back between 2% and 5% of the CR from T-4 auctions to T-1 auctions. This decision reflected the recognition that it is hard for DSUs to have certainty of availability and costs at T-4 stage, and hence to participate in a T-4 auction. The decision to hold back between 2 and 5% reflected the level of DSU participation in the SEM at the time the decision was made, with only around 320MW of DSU participating in the CRM in August 2016.

6.2.2 Whilst providing an indicative range of 2-5% of volume to be withheld from T-4 auctions in CRM Decision 3, the SEM Committee also recognised the need to consult periodically on the volume of the CR to withhold from T-4 auctions to the T-1 auctions, and that this amount may grow over time if the contribution from DSUs increases.

6.2.3 We have now seen the results from the first T-1 auction, and participation of DSU capacity has grown significantly. A total of 619MW of de-rated DSU capacity qualified for the first auction, of which 372MW was existing DSU capacity and 248 MW was new DSU capacity. 548 MW was successful in the auction. The total Qualified DSU volume represent 8.8% of the total CR of 7,030MW[47], and the successful DSU volume represented 7.8% of the CR.

6.2.4 Given the significantly higher DSU participation in the I-SEM CRM compared to the SEM, the SEM Committee is considering whether to increase the percentage of the CR withheld from the CY2022/23 T-4 auction to the T-1 auction from a maximum of 5% to around 7.5%, slightly lower than the level of successful DSU participation in the CY2018/19 T-1 auction.

6.2.5 The rationale for withholding capacity was to facilitate the participation of environmentally friendly demand side response, and to promote greater competition and efficiency by removing barriers to their participation. The case for withholding greater volumes is also stronger if we believe that there is a trend to increase demand side participation.

6.2.6 As explained in SEM-18-009, following the State aid decision, DSUs will be required to make RODPs from October 2020. This may impact upon the level of participation of DSUs.

6.2.7 The case for increasing the volume withheld also depends in part, upon the extent to which at least some of the demand side response is able to compete at T-4 stage. The US experience is that it is difficult for DSUs to compete at T-4 stage, and that was the reason we made the original decision in SEM-16-039. However, whilst it may be more difficult for DSUs to compete at a T-4 stage, latest evidence from GB indicates DSUs participation within T-4 capacity auctions.

6.2.8 As illustrated in Table 1 below, in the most recent GB CY2020/21 T-4 auction there was a substantial increase in the volume of DSU participation, with 1,410MW of successful DSU, which accounted for 2.7% of successful capacity and was more MW than successful in the CY2016/17 and CY2017/18 T-1 auctions. Whilst this may be evidence for an increasing trend of DSU participation rather than a preference for the T-4 auction, it demonstrates that some DSUs can compete at T-4 stage.

[47] Before adjustments for non-participating capacity

Table 1: DSU participation in GB auctions to date

	T-1		T-4	
	Awarded MW	% of Awarded Capacity	Awarded MW	% of Awarded Capacity
2016/17	474.743	59.1%		
2017/18	312.171	100.0%		
2018/19			174.17	0.4%
2019/20			456.455	1.0%
2020/21			1410.953	2.7%

6.2.9 The risk to withholding greater volumes is that we over-estimate the ability of the market to deliver competitive demand response, and are unable to procure sufficient capacity at T-1 stage (threatening security of supply), or are only able to do so at a distressed purchase price. However, the security of supply risk associated with withholding a larger proportion of the CR from the T-4 auction to the T-1 auction is partially mitigated by the role that data centres play on in high demand growth scenarios. Data centres are a high proportion of the projected demand growth in high growth scenarios, but if those scenarios materialise, are also likely to provide a disproportionate share of the demand response. Therefore, if we withhold a larger proportion of the CR back from the T-4 auction, if high demand growth scenarios materialise between T-4 and T-1, the supply of demand side response is also likely to be relatively high.

6.2.10 Furthermore, withholding larger volumes from the T-4 auction mitigates the risk of over-forecasting (since if demand forecasts are subsequently revised downwards, we are not locked into higher volumes). Arguably, the choice of the Least Worst Regrets approach increases the risk of over-forecasting demand, since it has a tendency to select higher demand scenarios.

6.2.11 We seek further consultation feedback on whether it is appropriate to withhold 7.5% of the CR from the T-4 auction to the T-1, or whether we should withhold 5% of the CR, staying at the top end of the previously stated range.

6.3 VOLUMES TO WITHHOLD BY CONSTRAINT AREA

6.3.1 In Section 2, we signalled the intention to reflect transmission constraints in T-4 auctions. If we withhold a proportion of capacity from the T-4 auction to the T-1 auction, we need to determine how the minimum MW in each constrained area will be adjusted for volumes withheld from the T-4 auction to the T-1 auction for CY2022/23, if at all.

6.3.2 As illustrated in Table 2, in the first T-1 auction, 79.3 de-rated MW of DSU capacity was awarded Reliability Options in Northern Ireland, which represented 4.9% of the minimum MW requirement for Northern Ireland. In the Greater Dublin area, 109.3MW of DSU were awarded Reliability Options, and this constituted 8.4% of the zonal minimum MW requirement.

Table 2: DSU capacity by zone, results from CY2018/19 auction

	Adjusted Capacity Requirement/ minimum MW	DSU capacity awarded RO (MW)	% of minimum requirement
All-island	6720	547.6	8.1%
Ireland	5260	468.3	8.9%
of which Greater Dublin	1300	109.3	8.4%
Northern Ireland	1630	79.3	4.9%

6.3.3 The SEM Committee is considering the following options:

- Option 1: Procure the full minimum MW requirement in the T-4 auction;
- Option 2: Withhold 5% of the zonal minimum MW from the T-4 auction to the T-1 auction for all zones; and
- Option 3: Withhold a zone specific % which reflects the historical pattern of DSU penetration by zone. If the zones and minimum MW remain the same, that would mean we would withhold approximately 5% of the minimum MW in the Level 1: Northern Ireland area, 8% in the Level 2: Greater Dublin area and across the Level 1: Ireland area.

6.3.4 Option 1 provides greater certainty, as the full zonal minimum MW is procured at T-4 stage. However, Option 1 could result in an inefficient solution, with more expensive capacity being procured in constrained zones than necessary at T-4 stage, if DSU capacity cannot compete effectively at T-4 stage.

6.3.5 Options 2 and 3 are reliant on procuring capacity to meet the zonal minimum MW at T-1 stage.

6.3.6 The decision could have a meaningful impact on competition and security of supply in certain zones. The Greater Dublin area, if it remains a constrained zone, sees demand growth driven by new data centres in certain scenarios, and the ability of DSU to contract with data centres in the Dublin area could have a meaningful impact on competition and security of supply.

6.4 SHAPE OF THE DEMAND CURVE

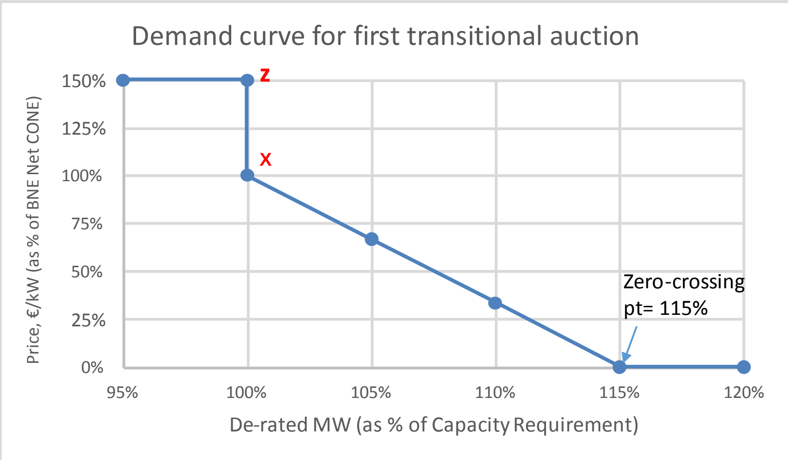
6.4.1 In CRM Decision 3 (SEM-16-039) the SEM Committee decided that, as with the majority of auctions, a sloping demand curve will be employed, in part to mitigate market power. CRM Decision 3 also set out the principles which would be used to determine the precise shape and positioning of the demand curve.

6.4.2 As illustrated in Figure 8, in the CRM Parameters decision paper (SEM-17-022), the position and slope were determined for the first T-1 transitional auction as follows:

- The curve will be horizontal at the Auction Price Cap (150% of the BNE Net CONE) between 0MW and 100% of the Capacity Requirement;

- The demand curve will be vertical at 100% of the Capacity Requirement between a price of 150% of BNE Net CONE and 100% of BNE Net CONE (between points Z and X on the diagram below);
- The demand curve will be a straight-line slope between point X and a zero-crossing point at 115% of the Capacity Requirement.

Figure 8: Demand curve for first T-1 capacity auction



6.4.3 However, whilst the SEM Committee prescribed this shape and positioning for the first T-1 auction, it left open the possibility that it might use a slightly different shape or position for T-4 auctions.

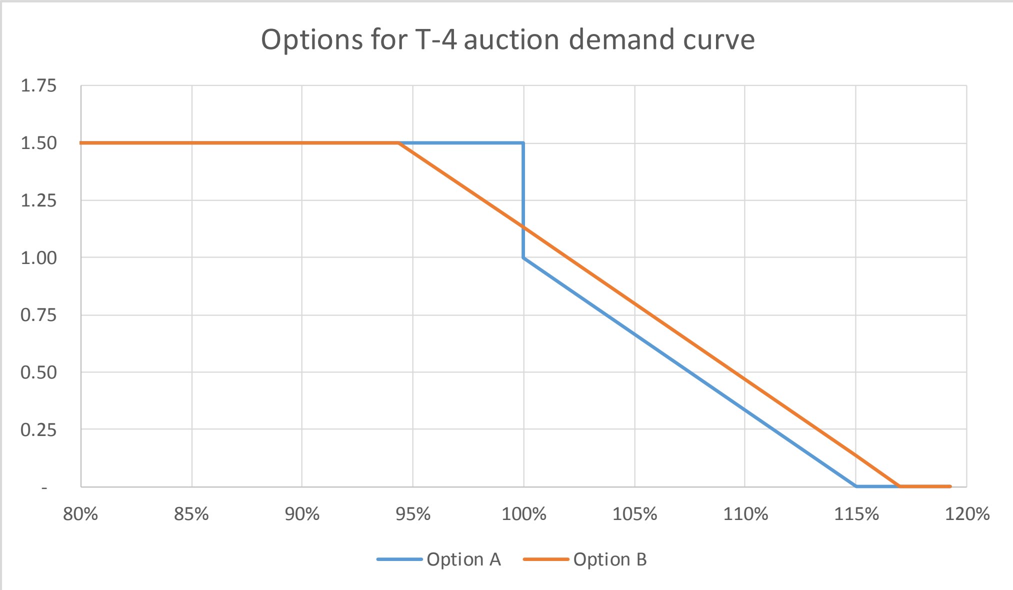
6.4.4 A key difference between the T-1 auction and the T-4 auction is that the T-1 auction represents the last realistic opportunity to contract capacity prior to delivery. In the T-1 transitional auctions we must aim to procure the CR in that auction at any price up to the Auction Price Cap. In the T-4 auction, if we cannot procure the CR at Net CONE, there are other later opportunities to procure the capacity shortfall at prices up to the Auction Price Cap, such as in the T-1 auction for that capacity year. In a T-1 auction, there is a strong imperative to ensure that we at least procure the Capacity Requirement, as there are few if any later opportunities to procure any shortfall in capacity.

6.4.5 The SEM Committee is therefore considering two options for the CY2022/23 T-4 demand curve shape and position, as illustrated in Figure 9:

- Option A: Same demand curve parameters as a function of the CR as used in the first T-1 auction, represented by the solid blue line in Figure 9;
- Option B: Represented by the solid brown line in Figure 9. The key difference between Option B and Option A is that the Option B curve continues to slope between the Net CONE value and the Auction Price Cap. By contrast the Option A curve is vertical between Net CONE and the Auction Price Cap at the capacity requirement. Under

Option B, if we buy less than the CR[48] in the T-4 auction we will aim to buy commensurately more in the T-1 auction[49].

Figure 9: T-4 demand curve options



6.4.6 The CR will be estimated by the TSOs in accordance with the approved methodology and based on the CY2022/23 demand forecast, approved by the SEM Committee and included in the Initial Auction Information Pack. This demand curve will then be adjusted for non-participating capacity following the Qualification Process. The final demand curve will then be published in de-rated MW terms in the Final Auction Information Pack.

6.5 SUMMARY OF CONSULTATION QUESTIONS

6.5.1 The SEM Committee welcomes views on the following consultation questions:

1) Should the proportion of the CR the SEM Committee hold back from the T-4 CY2022/23 auction for the T-1 CY2022/23 be increased from 5% to 7.5%, and why?

2) Should the minimum MW in each constrained area be adjusted for volumes withheld from the T-4 auction to the T-1 auction for CY2022/23? Which of Options 1, 2 and 3 do you prefer, and why?

3) Which of the demand curve options, Options A or B, in your view is the most appropriate for the first T-4 capacity auction, and why?

[48] With appropriate adjustments for non-participating capacity and volumes deliberately withheld ex ante for T-1 auctions to support DSU participation as discussed in Section 6.2.
[49] (or may hold T-3 or T-2 auctions if appropriate

7. T-4 AUCTION PRICE CAPS FOR CAPACITY YEAR 2022/23

This section discusses the other auction parameters which require consultation specifically for the first T-4 capacity auction for Capacity Year 2022/23, including:

- The level of the Auction Price Cap (APC) for the T-4 auction;
- The Existing Capacity Price Cap (ECPC) for the T-4 CY2022/23 auction; and
- Any changes to the approach to setting Net Going Forward Costs (NGFC) and Unit Specific Price Caps (USPC), and relevant templates for the Exception Application Process though which applications for USPCs should be submitted.

7.1 AUCTION PRICE CAP (APC)

7.1.1 The APC is the maximum price any capacity can be offered at, and therefore the maximum price that the auction can clear at, and the maximum Reliability Option fee that any capacity provider can be paid. In the CRM Parameters decision (SEM-17-022) the SEM Committee set the APC at 1.5 x Net CONE for the first transitional auction, equal to €123.19/kW/year for capacity providers in Ireland and £110.46747/kW/year for capacity providers in Northern Ireland[50].

7.1.2 The SEM Committee are currently consulting on an updated choice of BNE reference plant, and an estimate of BNE Net CONE of €86.0/de-rated KW/yr in 2022/23 money was published for a CCGT in Northern Ireland in CRM T-4 Best New Entrant consultation (SEM-18-025). The range of estimates for the Net CONE of CCGTs and OCGTs in Ireland and Northern Ireland (Table 56 of the T-4 Best New Entrant consultation (SEM-18-025)), which is reproduced below.

7.1.3 These estimates are likely to be refined, as part of ongoing BNE consultation, but we note that the estimated value of €86/kW/year in 2022/23 money is not much different to estimate CY2018/19 BNE Net CONE of €82.13/kW/yr.

Table 3: Latest Net CONE estimates, selected plant in the I-SEM

Table 56 – Gross and net CONE (€/kW – de-rated, nominal)

Jurisdiction		**Ireland**		**Northern Ireland**		
Technology	OCGT Distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT Dual
Gross CONE	**115.5**	**113.0**	**185.5**	**108.4**	**123.8**	**175.7**
Inframarginal rent	-4.0	-4.0	-80.8	-4.0	-4.0	-80.8
DS3 income	-16.1	-16.1	-8.8	-16.1	-16.1	-8.8
Net CONE	**95.4**	**93.0**	**95.9**	**88.4**	**103.8**	**86.0**

[50] based on a Net CONE estimate of €82.13/kW/year and an exchange rate of €1.1152=£1

7.1.4 The SEM Committee proposes to continue to set the APC as a 1.5 multiple of BNE Net CONE which was used in the first T-1 auction. The SEM Committee remains of the view that a multiple of 1.5 x Net CONE continues to be sufficient to absorb all the uncertainty given that:

- The 1.5 multiple contains a 50% margin for uncertainty in setting Net CONE
- In the SEM, capacity providers have been content to provide capacity at an average payment of less than Net CONE. The Annual Capacity Payment Sum has been based on Net CONE multiplied by the Capacity Requirement. This resulted in the same amount of money being spread over a large base so that capacity providers have typically been receiving around 70% of Net CONE in capacity payments. This level of payment has proved attractive to capacity providers, and has led to the provision of more capacity being available than required.

7.1.5 The SEM Committee remains mindful of market power concerns in keeping the APC at a multiple of Net CONE. Whilst the market power of existing generators may be diluted to some extent by the greater potential for new entry in T-4 auctions, the SEM Committee recognises that there may still be barriers to entry in terms of available sites with planning permission, and with access to firm transmission access.

7.1.6 The SEM Committee notes that this APC is significantly more than the £75/kW/year APC that GB continues to use for its T-4 auctions, and very much higher than GB T-4 auction clearing prices[51].

7.1.7 The GBP value of the APC will be set in the Initial Auction Information Pack based on the forward exchange rate for 2022/23 applying at the time.

7.2 EXISTING CAPACITY PRICE CAP (ECPC)

7.2.1 In CRM Decision 3 (SEM-16-039) we set out a suite of market power controls which cap the price at which Existing Generators and interconnectors can offer their Qualified Volume into the I-SEM CRM auctions (whether transitional T-1 auctions, or T-4 auctions):

- The Existing Capacity Price Cap (ECPC) is a uniform (i.e. non-technology specific) cap which caps the price that Existing Generators and interconnectors can offer volume at, unless they apply for higher Unit Specific Price Caps (USPC)[52]. New Capacity[53] and DSUs are not subject to the ECPC, and may bid up to the APC;
- An Existing Generator which has Net Going Forward Costs (NGFCs) which exceed ECPC can apply to the RAs to obtain a USPC[54].

7.2.2 In the CRM Parameters decision (SEM-17-022) the SEM Committee decided to set ECPC at 0.5 x Net CONE for the first T-1 auction. In the CY2018/19 T-1 Initial Auction Information Pack this

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[51] GB uses a 1.5x multiplier, but GB NetCONE is only 49£/kW

[52] or submit an Opt-Out Notification on the grounds that they are going to close before the end of the relevant Capacity Year

[53] Generators which meet the criteria for new build generation will not be subject to the Existing Capacity Price Cap and may bid at a price up to the Auction Price Cap

[54] SEM-16-039 referred to Price-taker Offer Caps, which were subsequently called Unit Specific Price Caps (USPCs)

was subsequently set at €41.06/kW/year and £36.8185/kW/year for the CY2018/19 T-1 auction.

7.2.3 SEM-17-022 set out the SEM Committee's rationale for setting the ECPC at 0.5 x Net CONE for the first transitional auction. SEM-17-022 noted that…

"the ECPC performs two key functions, and the level of the ECPC needs to reflect these two key functions.

Firstly, it limits the ability of generators with market power, but with low NGFCs to exercise their market power through making high offers. Given the significant concerns about market power in the CRM (see SEM-16-010), it is important that the ECPC is not set at a level significantly above where we expect the market to clear in current market conditions. As we explained in the consultation document (SEM-16-073), and re-iterated in our response on sunk costs, we would anticipate that in the current market, with significant capacity in excess of the Capacity Requirement, in the absence of market power we would expect the auction to clear well below Net CONE, and not far from 0.5 x Net CONE.

Secondly it provides a filter to ensure that only those USPC applications which the RAs need to scrutinise (because they may have a material impact on the clearing price or pay-as-bid prices) are scrutinised. If the ECPC is set too low, then offer prices which are below the clearing price (and therefore will have no impact on the clearing price or pay-as-bid prices) will need to be reviewed, imposing an unnecessary administrative burden on both the RAs and bidders.

The SEM Committee considers that setting the ECPC at 0.5 x Net CONE strikes an appropriate balance between the objectives of protecting consumers from the potential for bidders to exercise market power, and not placing an excessive workload on the RAs and market participants."

7.2.4 The CY2018/19 T-1 auction cleared at €41.80/kW/yr, i.e. just above ECPC, so that those capacity providers which influenced the clearing price and/or were awarded pay-as-bid Reliability Options. The SEM Committee therefore achieved the balance that it was seeking. Based on current estimates of the revised BNE Net CONE, the SEM Committee is of the view that keeping ECPC at 0.5 x Net CONE is appropriate for the first T-4 auction.

7.3 METHODOLOGY AND PROCESS FOR CALCULATING NGFC AND USPC

7.3.1 The CRM Parameters decision (SEM-17-022) stated that the RAs will calculate the NGFCs and USPCs for generators based on the following formula:

- NGFC = Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets + appropriate proportion of unavoidable future investment),0] + Expected Reliability Option difference payments

  Where the appropriate proportion of unavoidable future investment will be determined on a case-by-case basis

- USPC: Unit Specific Price Caps will be set based upon Net Going Forward Costs (NGFCs) according to the following formula:

  Max allowed USPC bid = 110% x RAs' NGFC estimate, updated following review of USPC application.

7.3.2 Whilst SEM-17-022 and its accompanying consultation paper (SEM-16-073) set out some of the detail of how the RAs/SEMC would evaluate key elements, such as fixed operating costs, gross infra-marginal rent, ancillary services income etc, inevitably some detailed implementation decisions remained to be made by the RAs/SEMC during the USPC implementation process as regards to how USPCs should be calculated

7.3.3 Following the T-1 CY 2018/19 USPC process the SEM Committee published an information paper, SEM-17-090, which set out further details of the approach the RAs / SEM Committee used in assessing applications in the first T-1 auction.

7.3.4 The RAs / SEM Committee does not intend to make any significant policy changes to the approach used to the setting of USPCs for the CY2022/23 T-4 auction. However:

- The approach will need to be tailored to a T-4 auction rather than a T-1 auction; and
- The Excel data templates will need to be updated to be appropriate for a T-4 auction.

7.3.5 A separate briefing note will be published in due course outlining the exception application process including the excel templates.

7.3.6 We discuss the key changes below.

Investment and maintenance

7.3.7 The USPCs for CY2022/23 may include any Unavoidable Future Investment (UFI) allowances awarded in the decision relating to the CY2018/19 T-1 auction, where that allowance was to be spread over an investment of 5 or more Capacity years[55].

7.3.8 Any UFI qualifying investments which existing generators are expected to make in respect of CY2019/20, will need to be submitted as part of the USPC setting process for the CY2019/20 T-1 transitional auction. According to the timetable published by the TSOs, the USPCs will need to be submitted by the CY2019/20 T-1 Auction Exception Application Date of 28 June 2018[56]. Approved UFI allowances in respect of CY2019/20 may also be carried forward to CY2022/23, where the SEM Committee determines those CY2019/20 allowances are to spread over 4 or more Capacity Years.

7.3.9 The Exception Application process for the CY2022/23 T-4 auction will occur before the Exception Application process for the transitional CY2020/21 and CY2021/22 T-1 auctions. The T-4 CY 2022/23 auction timetable is expected to be published early June 2018 and will set out the timelines for submitting exception applications to the RAs.

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[55] Investment allowances may be spread over up to 10 years

[56] 2019/20 T-1 Capacity Auction Timetable: http://www.sem-o.com/ISEM/General/CAT1920T-1%20-%202019%202020%20T-1%20Capacity%20Auction%20Timetable.pdf

7.3.10 **Investment plans in respect of CY2020/21 and CY2021/22 will need to be included within the T-4 USPC submission for CY2022/23, if the market participant is seeking to have an element of allowance carried forward to CY2022/23**. It is in the interest of market participants to provide this full information in their T-4 USPC submission for CY2022/23. For instance, if at T-1 stage, a market participant decides that it has a UFI in CY2021/22, the SEM Committee may decide that the investment has a life of 5 years. Just because the market participants decided not to submit that project in its CY2022/23 T-4 submission will not stop the SEM Committee deciding that recovery should be "spread" over 5 years, even though the market participant omitted to include the UFI in its CY2022/23 USPC T-4 submission back in 2018.

7.3.11 For CY 2018/19, generation asset owners typically had a reasonable idea where in the maintenance cycle they were going to be, and what the resulting capex requirements would be for their plant in 2018/19. However, we recognise that there is significant uncertainty about the likely running regimes for individual units between now and 2022/23, and the resulting impact on investment and running regimes. It may not be possible to use historic running and maintenance as a guide. We would expect participants to clearly evidence changes, but it may be appropriate to move to a more averaged approach, based on long run average levels of investment and maintenance, and not focus excessively on expenditure in or for a particular year.

7.3.12 We seek consultation feedback on the issues associated with making UFI submissions in respect of CY2020/21, CY2021/22 and CY2022/23 as part of the CY2022/23 T-4 auction Exception Application process.

Projecting costs and inflation

7.3.13 For a number of cost categories, in the CY2018/19 T-1 USPC setting process we needed to inflate current or historical costs to CY2018/19 costs.

7.3.14 As set out in SEM-17-090, we used Bank of England (BoE) and Central Bank of Ireland (CBoI) inflation projections to inflate current operating cost expenditures to 2018/19 values, where relevant. The same approach cannot be applied to a T-4 auction, as neither the BoE nor the CBoI make projections inflation projections 4-5 years forward. For the T-4 CY2022/23 auction, we plan to use a 2% p.a. inflation projection to project nominal 2022/23 values from nominal 2018 values. 2% is the inflation target (not a forecast) of both the Bank of England and the European Central Bank. We propose to use this value, given the absence of longer term inflation BoE and CBoI inflation projections for either the UK and Ireland.

7.4 SUMMARY OF CONSULTATION QUESTIONS

7.4.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you agree with the proposal to keep the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?

2) Do you agree with the proposal to keep ECPC at 0.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?

3) USPC setting: Do you agree with the proposed approach for UFI submissions?

4) USPC setting: Do you agree with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23?

8. DERATING FACTORS

8.1 INTRODUCTION

8.1.1 The RAs are responsible for calculating the interconnector de-rating factors, according to the methodology determined by the SEM Committee.

8.1.2 The SEM Committee set out the RAs' approach to calculating the interconnector de-rating factors in SEM-16-082, and the associated appendix on interconnectors SEM-16-082b. SEM-16-082 and 16-082b set out *inter alia*:

- The key inputs to be used for the CY2018/19 T-1 auction;
- The methodology, which includes the calculation of An External Market De-rating Factor (EMDF), a Forced Outage Rate (FOR) assumption, a Scheduled Outage Rate (SOR assumption) all of which combine with system wide de-rating curves to produce Interconnector De-rating Factors. As with other technologies, the de-rating factor to be applied to any specific interconnector is a function of its Initial Capacity (i.e. its capacity before de-rating). The final de-rating factors used in the CY2018/19 T-1 auction are set out in Table 4.

8.1.3 In SEM-18-009 we consulted on some changes to the proposed methodology to apply in respect of CY2019/20, including:

- How to generate the updated input assumptions for CY2019/20;
- A proposed refinement to the methodology to use a Least Worst Regret Cost approach to selecting which demand scenario to use for GB for CY2019/20;
- Whether adjustments need to be made to the GB EMDF to reflect the likely impact of the proliferation of smaller GB capacity units on coincident scarcity.

8.1.4 The SEM-18-009 consultation closed on 19 April 2018 and the SEM Committee will publish its decision in respect of these issues in late May/early June. The decisions with respect to use of a Least Worst Regrets approach to select the GB demand scenario, and the treatment of smaller GB capacity units will also apply to CY2022/23 for the T-4 auction.

8.1.5 In this section the SEM Committee sets out:

- How to generate the updated input assumptions for CY2022/23; and
- Issues associated with the move from the interim "interconnector-led" solution to the hybrid solution, in accordance with State aid undertaking to allow direct participation of cross-border capacity from auctions occurring in 2020 or later

8.1.6 The RAs' final interconnector de-rating factors will be included in the Initial Auction Information Pack. However, we show indicative results, and how they compare with CY2018/19 T-1 factors in Table 4.

8.1.7 The potential impact of coincident scarcity is impacted by the decisions on the Capacity Requirement, including the potential change to the inclusion of a volume for reserve in the Capacity Requirement or a change to the LOLE security standard. The inclusion of reserve or tightening the LOLE standard reduces the probability of scarcity in the SEM and the remaining incidents of scarcity are more likely to coincide with scarcity in GB. This arises as scarcity is more dependent on extreme demand events which are likely to also impact GB.

CY2022/23 Inputs

8.1.8 For this consultation document, the assumption for the I-SEM Capacity Requirement was re-estimated based on the increase in GCS demand between 2022 and 2023[57]. This suggested an increase of approximately 60MW based on the previous relationship between Capacity Requirement and the range of demand forecasts in the GCS, i.e. that the least-worst regrets analysis tends to pick a demand scenario close to the High Demand scenario in the GCS. For the final decision, an estimated value of the Capacity Requirement will be obtained from the TSOs using the approved Capacity Requirement and De-rating Methodology.

8.1.9 As set-out in the Capacity Requirement and De-rating Methodology Decision (SEM-16-082), the historic interconnector outage rates are determined based on the most recent 10 years of historic data. The historic determination of interconnector outage rates was updated, for this consultation paper, to include data to the end of June 2017. This is consistent with the decision to use 10 years of historic data for the Interconnector Technology Class. For the final decision, data for the whole of 2017 should be available for incorporation into this historical determination.

8.1.10 For this consultation document, the assumptions for GB which are derived from NGC's Future Energy Scenarios (FES) have been updated to use the 2017 FES.

8.1.11 The export limit from I-SEM to GB from the Moyle interconnector has been reduced to 80MW (from the 450MW used for the 2018/19 T-1 Auction), reflecting the expected reduction in the ability of the GB transmission system to accept exports above this level. This reduces the probability of scarcity in GB driving scarcity in the I-SEM.

8.1.12 These assumptions will be refreshed prior to determination of the interconnector de-rating factors to be published in the Initial Auction Information Pack for the 2022/23 T-4 Auction.

Indicative results

8.1.13 The analysis of coincident scarcity in the SEM and GB produced a broad range of possible values of EMDF given the variation in assumptions between the four Future Energy Scenarios[58] by 2022/23. As in the 2019/20 T-1 Parameters Consultation (SEM-18-009), EMDF values were determined using both a 7% and 10% assumption for average forced outage rate in GB given the sensitivity to this assumption. The values of EMDF ranged from 32% to 95%.

8.1.14 As noted above, the inclusion of additional capacity requirement in respect of operating reserve, or a tighter security standard, reduces the incidence of scarcity in the SEM and increases the coincidence of scarcity between the SEM and GB. However, the variation in generation mix and outage assumptions in GB continues to generate a broad range of possible

[57] Latest available TSOs Generation Capacity Statement 2017-2026 used

[58] A set of future scenarios for the GB market produced by NC.

out-turn values for EMDF. For likely potential increases to the capacity requirement, EMDF values range from 18% to 91%.

8.1.15 The RAs see clear benefit in avoiding volatility in the level of EMDF from year-to-year. On the basis of the coincident scarcity analysis, and given the uncertainties involved and the volatility of the key FES assumptions from forecasting year to forecasting year, the RAs are proposing to retain the EMDF value of 60% used in CY2018/19 and CY2019/20 for CY2022/23. However, this will be reviewed when the analysis is refreshed for the Decision paper based on the latest data available at that time.

8.1.16 Indicative outage rates for the GB interconnectors will be:

- Forced Outage Rate: 10.3%
- Scheduled Outage Rate: 5.1%

8.1.17 As set-out in SEM-16-082, these outage rates and the EMDF feed into the standard TSO methodology to determine the Capacity Requirement and De-Rating Factors. Interconnectors are treated as a technology class in this methodology and are given a marginal de-rating using the same process as other generators. This marginal de-rating is then scaled by the EMDF to give the final de-rating.

8.1.18 For this consultation paper, no EMDF has been determined for markets other than GB. It is not intended to determine an EMDF for any other market for the Initial Auction Information Pack, unless a clear requirement emerges from this consultation related to a planned interconnection which will participate in the 2022/23 T-4 Auction.

Table 4: Indicative interconnector de-rating factors

	T-1, CY2018/19 Initial Auction Information Pack	**T-4, CY2022/23 Estimated**
EMDF	60%	60%
Forced outage rate	6.9%	10.3%
Scheduled Outage Rate	3.7%	5.1%
Overall Interconnector De-rating (450MW unit)	48%	44%

Issue moving to the enduring hybrid-solution for cross border capacity

8.1.19 The first T-4 auction will not have direct participation by cross-border capacity. It will operate, at least initially on the interim, interconnector-led approach to the treatment of cross-border capacity which uses the methodology for interconnector de-rating set-out above. However:

- The current intention is that I-SEM will move to the enduring hybrid solution for cross-border trading from the auctions taking place in 2020, i.e. the T-1 auction for 2021/22 and T-4 auction for 2024/25;
- It may be feasible to operate a two-step approach whereby whilst cross-border capacity does not participate directly in the CY2022/23 T-4 auction, there is a

subsequent secondary auction for CY2022/23 capacity in which cross-border capacity participates.

8.1.20 This means that the T-4 auctions for 2022/3 and 2023/4 would use the interim solution, but the T-1 auctions for 2021/2, 2022/3 and 2023/4 would use the enduring hybrid solution. This creates two potential issues:

- **Consistency of Interconnector De-Rated Capacity**: The EMDF will have a potentially different role in the enduring cross-border solution where external CMUs participate directly. This could create unnecessary volatility in the treatment of interconnector de-rated capacity over the period where the cross-border solution is in transition.

- **Consistency of signals to external CMUs**: External CMUs could fully participate in the first capacity auctions for CY2021/22 and CY2024/25 but not for CY2022/23 and CY2023/24 (based upon auctions scheduled in 2020 onwards). For these years, the full de-rated interconnector capacity will likely have been awarded in the T-4 auction in which they were unable to take part. This could lead to inconsistent economic signals to capacity in external markets.

Consistency of Interconnector De-Rated Capacity

8.1.21 The enduring hybrid solution has not been fully defined at this stage, however CRM Decision 2 (SEM-15-104) does set out the basic structure of this solution. The hybrid solution would retain the need to de-rate interconnectors but is not explicit about what should be considered in this de-rating. Each external generator unit would also be de-rated based on its reliability in the same basic manner as is used for units within the I-SEM.

8.1.22 The new EU Regulation on electricity markets is only a proposal at this stage, and was last revised on 9/11/2017[59]. In its latest form, this requires, as part of article 21, that Regional Security Co-ordinators determine a maximum entry capacity for each interconnector, taking account of its technical availability and the likely concurrence of system stress. This requirement appears consistent with the current I-SEM approach to interconnector de-rating using historic interconnector outages and an EMDF accounting for the concurrence of system stress. This strongly suggests a continuing role for a form of interconnector de-rating in the enduring solution similar to that used in the interim solution. Prior to full definition of the planned EU approach, it would seem sensible to retain the current interconnector de-rating methodology.

8.1.23 Article 21 of the latest draft of the EU Regulation, also provides scope for a Member State to prevent capacity from participating in two (or more) capacity mechanisms. If capacity does participate in two capacity mechanisms, then it would be liable to penalties for failure to provide availability in both markets if they have concurrent system stress.

8.1.24 Renewable capacity in GB is rewarded through the ROCs or CfD FiT schemes. For both of these support mechanisms, any capacity income from the I-SEM CRM would be additional to the support already paid. On the basis of the State aid decision for the I-SEM CRM, such capacity

[59] ST 10681 2017 REV 1 - 2016/0379 (COD): Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity (recast)

would not be able to participate in the CRM and retain its ROC and CfD FiT contracts. Experience from the I-SEM suggests this capacity would prefer to keep its renewable support revenue and so would not participate in the I-SEM CRM.

8.1.25 If capacity which was contracted in GB were prevented from participating in the I-SEM CRM for the enduring solution then this, in conjunction with the likely restrictions on renewable generation, might significantly limit the GB capacity that could participate in the I-SEM CRM. In this situation, while capacity would still be delivered to the I-SEM at times of stress based on the functioning of the energy markets, some of this capacity may not have been awarded Reliability Options in the CRM. Equally, if GB capacity is not awarded Reliability Options to take up all of the de-rated interconnector capacity for any other reason, e.g. on the basis of the prices offered, then this capacity may still be delivered to the I-SEM at times of system stress.

8.1.26 While the design of the enduring hybrid solution remains undefined, there is a clear potential for the capacity contracted from external CMUs to be lower than the de-rated capacity of the interconnector(s) and the capacity which is expected to be delivered to the I-SEM. In such a situation, this unused de-rated interconnector capacity might sensibly be used to adjust the Demand Curve, as is currently the case for capacity which chooses not to participate in the auction but which is still expected to provide capacity to the I-SEM, to avoid over-contracting for capacity in the I-SEM.

8.1.27 This approach should reduce the volatility in the capacity delivered to the I-SEM as the auction transitions from the interim to the enduring cross-border solution. There may still be some volatility when the new Electricity regulation comes into force, as the detailed calculation of de-rated interconnector capacity will vary from the current I-SEM determination. In advance of completion of the new regulation and more detail of the methodology to determine de-rated interconnector capacity, there is little that can currently be done to manage this uncertainty.

Consistency of signals to external CMUs

8.1.28 Once the enduring hybrid solution has been fully defined, the de-rated interconnector capacity for each affected Capacity Year (e.g. 2022/23 and 2023/24) could be re-offered to external CMUs through an additional auction. Only external CMUs would participate in this auction and, in line with the hybrid solution, would establish an auction clearing price for the external capacity zone[60]. This would allow external CMUs full access to the de-rated interconnector capacity for all auctions covering the transition between cross-border trading solutions, expected to be CY2022/23 and CY2023/24. This would provide consistent signals to such capacity across the whole period of transition between cross-border trading solutions.

8.1.29 The expectation is that the de-rated interconnector capacity will have cleared in the original auction for the Capacity Year and capacity awarded to the relevant interconnector owner at a price: mostly likely the Auction Clearing Price. Re-auctioning this capacity would require the capacity awarded to the interconnector owners to be reduced, potentially to zero. This would

[60] This would be analogous to the explicit auction model referenced in paragraph 2.4.35 of SEM-15-104

result in a reduction in both the capacity fee payable to the interconnector owners and a corresponding reduction in the obligation to deliver capacity and make difference payments.

8.1.30 It is unlikely that the clearing price for the interconnector capacity re-auction will match the Auction Clearing Price from the original T-4 auction for the relevant Capacity Year. It would be undesirable for this interconnector capacity re-auction to clear at a price above the original T-4 Auction Clearing Price, as such an outcome would be inconsistent with the results of the original auction and is unlikely to provide the continuity of economic signal to capacity in the external market. This suggests that offers into the interconnector capacity re-auction should be capped at the T-4 Auction Clearing Price, but it should be noted that there is no obligation on capacity in an external market to participate in the I-SEM CRM.

8.1.31 If the new auction clears at a lower price than T-4 Auction Clearing Price, then the capacity payments due to external CMUs will be lower than those due to the interconnector owners under the original auction. This reduction in the cost of capacity could be returned to Suppliers by reducing their obligations to make payments for capacity or could be retained by the interconnector owners. The latter approach seems more consistent with the direction of travel at the European level with congestion rents being allocated to the interconnector.

8.1.32 If not all of the de-rated interconnector capacity clears in the new auction, then this capacity could be retained by the interconnector owners or used to reduce the Demand Curve as set out above.

8.1.33 Clearly, the precise details of any such additional auctions for external CMUs and the impact on capacity already awarded to the interconnector owners will need to be reviewed in light of the detailed design of the hybrid solution and the final (or latest) form of the new EU energy regulation (COM2016/0379).

8.2 SUMMARY OF CONSULTATION QUESTIONS

8.2.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you have any views on the proposal of EMDF value of 60% subject to review and update of the analysis for the decision paper?

2) Do you expect to be applying to qualify a new interconnector between the I-SEM and an external market other than GB?

3) Do you have any feedback on the issues around transitioning from the interim to the hybrid solution for cross-border trading of capacity?

9. NEW CAPACITY INVESTMENT RATE THRESHOLD

9.1 INTRODUCTION

9.1.1 The New Capacity Investment Rate Threshold (NCIRT), is the minimum investment that a capacity provider must make to qualify for a multi-year fixed fee Reliability Option[61]. In the CRM Parameters decision (SEM-17-022), we set the NCIRT at 40% of the gross investment cost of a BNE plant, which was estimated at €300/de-rated kW. This decision was informed by the international benchmarks discussed in SEM-17-022.

9.1.2 In SEM-18-009, the SEM Committee consulted on keeping the NCIRT at €300/de-rated kW for the CY2019/20 auction, pending a full review of BNE costs.

9.1.3 The RAs recently carried out a review of the BNE cost estimates and the report contains updated estimate of the gross investment costs of OCGTs and CCGTs in Ireland and Northern Ireland[62]. The SEM Committee is currently consulting on the choice of BNE reference plant, and BNE Net CONE. As shown in the Best New Entrant consultation report (SEM-18-025a), there is little difference between the Net CONE of:

- An OCGT, which has lower investment costs, but is forecast to earn less IMR; or
- A CCGT, which has higher investment costs, but is forecast to earn more IMR and a lower overall Net Cost of New Entry (Net CONE).

9.1.4 Estimates are subject to further refinement, and at this stage it is possible that the BNE reference plant could be either an OCGT or a CCGT.

9.1.5 In Table 34, of the Best New Entrant consultation report (SEM-18-025a), the investment costs for OCGTs running on distillate, OCGTs running on gas and CCGTs in both Ireland and Northern Ireland are set out. The gross investment costs in €m for each plant are reproduced in Table 5 below, which then converts them to €/de-rated kW using the de-rating factor employed in the CY2018/19 auction. We have converted the investment cost numbers from 2017 values by inflating them by an expected average 2% inflation over 5.75 years.

9.1.6 The key results to note are that:

- 40% of the Gross Investment Costs are in the range €305/de-rated KW to €388/de-rated KW in 2022/23 money, with OCGTs being at the lower cost end of the range and CCGTs being at the higher cost end of the range;
- This analysis does not represent strong evidence in favour of a change to the NCIRT of €300/de-rated KW for the time being.

[61] which has been fixed as a maximum of 10 years in CRM Decision 3 (SEM-16-039)
[62] T-4 Best New Entrant Consultation – Poyry Report SEM-18-025a
https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-025a%20Cost%20of%20New%20Entrant%20Peaking%20Plant%20and%20Combined%20Cycle%20Plant%20in%20I-SEM_FINAL.pdf

Table 5: Estimates of gross investment costs

	Ireland			Northern Ireland		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
EPC costs	93.00	92.50	266.60	91.60	92.00	264.60
Site procurement cost	0.70	0.70	3.00	0.90	0.90	3.70
Electrical connection costs	5.70	5.70	5.70	5.70	5.70	5.70
Water connection costs	0.50	0.50	0.60	0.50	0.50	0.60
Gas connection costs	-	3.70	4.60	-	3.70	4.60
Owners contingency	4.70	4.60	13.30	4.60	4.60	13.20
Financing costs	1.90	1.90	5.30	1.80	1.80	5.30
Interest during construction	1.30	1.40	5.70	1.20	1.20	5.20
Insurance	0.80	0.80	2.40	0.80	0.80	2.40
Initial fill of fuel oil tanks	1.80	1.60	4.30	2.40	2.10	5.70
Project development	5.60	5.60	16.00	5.50	5.50	15.90
Commissioning utilities costs	2.30	2.30	6.70	2.30	2.30	6.60
Operating spares	1.40	1.40	4.00	1.40	1.40	4.00
Accession fees	-	-	-	-	-	-
Participation fees	-	-	-	-	-	-
Total gross investment cost €m, 2017 prices	**119.70**	**122.70**	**338.30**	**118.70**	**122.60**	**337.50**
MW nameplate	190.20	198.60	447.40	190.20	198.60	447.40
De-rating factor (CY2018/19)	90.90%	90.90%	87.20%	90.90%	90.90%	87.20%
MW de-rated	172.89	180.53	390.13	172.89	180.53	390.13
Gross investment cost €/derated kW	692	680	867	687	679	865
40% of gross investment cost €/derated kW, 2017 prices	276.94	271.87	346.86	274.62	271.65	346.04
40% of gross investment cost €/derated kW, 2022/23 prices	**310.33**	**304.66**	**388.69**	**307.74**	**304.41**	**387.77**

9.1.7 The SEM Committee now seeks feedback on the evidence presented in this document on gross investment costs, and will make the decision on the NCIRT value in conjunction with the choice of new BNE reference plant. However, the SEM Committee is considering keeping the NCIRT at €300/de-rated kW in nominal terms, given that:

- Respondents to the previous CRM Parameters consultation generally supported a lower limit, not least because the I-SEM regime does not have a refurbishment category, for those investors investing an intermediate amount; and
- The estimates of gross investment costs have not changed substantially.

9.2 SUMMARY OF CONSULTATION QUESTIONS

9.2.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you agree with keeping NCIRT at €300/kW, in the light of new evidence on BNE gross investment costs? Does your view depend on the choice of BNE reference plant resulting from the Best New Entrant consultation (SEM-18-025)?

10. SUMMARY OF PARAMETERS

10.1 INTRODUCTION

10.1.1 We have summarised the position on the key parameters for CY2022/23 in Table 6 below:

- Some parameters remain unchanged from CY2018/19;
- Other parameters will be updated only for changes in assumptions (e.g. inputs relevant to CY2022/23 rather than CY2018/19);
- Other parameters will reflect refinements consulted on in SEM-18-009 (State Aid Update, 2019/20 T-1 Capacity Auction Parameters and Enduring Storage De-rating Methodology), with the relevant decisions expected to be published in late May/early June 2018;
- Other parameters will reflect specific T-4 issues consulted on in this document.

Table 6: Summary of key CY2022/23 parameters

Parameter	Actual T-1 2018/19	Proposed T-1 2019/20	Description of Potential Changes for T-4	
			Policy	Inputs and values
Auction Price Cap	€123,190/MW per year	€123,190/MW per year	No change: Keep at 1.5 x Net CONE	Update for new Net CONE estimate resulting from **[consultation ref]**
Existing Capacity Price Cap	€41,060/MW per year	€41,060/MW per year	No change: Keep at 0.5 x Net CONE	Update for new Net CONE estimate resulting from **[consultation ref]**
Capacity Requirement	7030 MW	Update to latest demand forecast for CY2021/22	Consulting on inclusion of a proportion of operating reserve requirement and/or LOLE standard change in Section 4	To be updated based on latest demand forecast for CY2022/23
Volume withheld from T-4 to T-1	Not relevant	Not relevant	Being consulted on in Section 6	SEMC to set out in decision document corresponding to this consultation
Indicative Demand Curve Shape	As per CY2018/19 T-1 FAIP	Same shape as CY2018/19 T-1	Being consulted on in Section 6	To be updated based on latest demand forecast for CY2022/23, and published in CY2022/23 T-4 IAIP. Final demand curve adjusted for non-participating capacity to be publsihed in CY2022/23 T-4 FAIP
Locational Capacity Constraints	Dublin & NI, full definition in CY2018/19 IAIP & FAIP	Dublin and NI, full definition updated in CY2018/19 IAIP & FAIP	Inclusion in auction design being consulted on in Section 2	Area definition and minimum MW to be based on updated TSO analysis for CY2022/23. Area definitions to be publsihed in CY2022/23 T-4 IAIP. Minimum MWs to be published in CY2022/23 T-4 FAIP
De-rating Curves Storage Capacity	Interim arrangement	Enduring approach consulted on in SEM-18-009	To be set out in decision document to SEM-18-009	Final values to be updated by TSOs, approved by SEMC and included in CY2022/23 T-4 IAIP
De-rating Curves for DSUs	System wide de-rating used	Specific time limited de-rating consulted on in SEM-18-009	To be set out in decision document to SEM-18-009	Final values to be estimated by TSOs, approved by SEMC and included in CY2022/23 T-4 IAIP
De-rating Curves for Interconnectors	As per IAIP/FAIP	Minor variation due to updated inputs	Consulting on how to generate certain input assumptions in Section 8	Minor change resulting from updating inputs. Indicative numbers calculated by RAs shown in Section 8. RAs will calculate final values for approval by SEMC to be published in the CY2022/23 T-4 IAIP
De-rating Curves by Tech Class (excluding Interconnectors)	As per IAIP/FAIP	TSOs to update in advance of Initial Auction Information Pack	No changes	TSOs to update estimates for SEMC approval and included in IAIP with potential minor changes to reflect input assumption changes
Tolerance Bands	All 0% except DSU 100%	As CY2018/19, except proposal to allow Other Storage Units a tolerance band similar to DSUs consulted on in SEM-18-009	To be set out in decision document to SEM-18-009	No change from CY2019/20 T-1 auction proposed
New Capacity Investment Rate Threshold	€300,000 /MW; 40% BNE Invt Cost	€300,000 / MW	Consulted on in Section [x-ref]	No change from CY2018/19 proposed
Performance Securities	As per FAIP - staggered rates	Same as for CY2018/19	Same as for CY2018/19	Same as for CY2018/19
Termination Charges	As per FAIP - staggered rates aligned with performance	Same as for CY2018/19	Same as for CY2018/19	Same as for CY2018/19
Administered Scarcity Price	Reserve 500MW; ASP €500 - €3000/MWh	Reserve 500MW; ASP €500 - €3000/MWh	Being consulted on in Section 5	SEMC to set out in decision document corresponding to this consultation
Strike Price parameter: DSU Floor Price	€500 MW	€500 MW	No change	€500 MW
Strike Price parameters: Others	As per FAIP	Fuel/carbon/transport adders to be updated to CY2019/20	No change	Fuel/carbon/transport adders to be updated to CY2022/23. TSOs to provide updated values for SEMC approval for IAIP
Annual Capacity Payment Exchange Rate	As per FAIP	Updated exchange rate	No change	TSOs to propose indicative rate for IAIP and final rate for FAIP, based on market quotes for CY2022/23 forward period
Awarded Capacity	Zero	Zero	No change	Zero
Annual Stop-Loss Limit	1.5	1.5	No change	1.5
Billing Period Stop-Loss Limit Factor	0.5	0.5	No change	0.5

10.2 SUMMARY OF CONSULTATION QUESTIONS

10.2.1 The SEM Committee welcomes views on the following consultation questions:

1) Do you have any comments on any of the parameter summarised in Table 6, which are not already covered in your responses to other consultation questions?

11. NEXT STEPS

11.1.1 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. The SEM Committee would particularly want to receive evidence supporting any alternative to the proposals, where possible supported by quantitative analysis.

11.1.2 The SEM Committee intends to make a decision in September 2018 on the T-4 parameters to be applied to the Capacity Year 2022/23 for which the capacity auction is due to take place March 2019.

11.1.3 Responses to the consultation paper should be sent to Karen Shiels (Karen.Shiels@uregni.gov.uk) and Kevin Lenaghan (Kevin.Lenaghan@uregni.gov.uk) by 17.00 on Tuesday, 26 June 2018. Please note that we intend publishing all responses unless marked confidential.

11.1.4 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.

Appendix A Auction Format

A.1 Introduction

In this appendix we set out the TSOs' proposed Alternative Auction Solution Methodology which would be used to apply Auction Format Option C, which does not procure additional capacity in respect of transmission constraints but instead displaces an equivalent MW of in merit capacity.

A.2 Background

The Capacity Market for Ireland and Northern Ireland centres around annual Capacity Auctions that take place approximately four years in advance of delivery (T-4 auction) and approximately one year in advance of delivery (T-1 auction). These auctions match offers from Participants in respect of their Capacity Market Units against a Demand Curve set by the Regulatory Authorities. The auction is combinatorial in nature as it seeks to maximise Net Social Welfare subject to satisfying various constraints including inflexibility constraints (where offers can be all or nothing) and Locational Capacity Constraints (where a certain predetermined quantity of capacity must clear in particular constraint areas).

In the short term, in line with the SEM Committee decision SEM-16-081[63], the Capacity Market Code (in M.4 and M.6) provides for the interim solution of Option B, which entails any capacity secured to meet constraints being additional to that which clears in the unconstrained auction. The State aid decision allows for the Option B auction format to apply to the first two transitional auctions i.e. CY2018/19 and CY2019/20. After which Option C format will apply in the short term. The State aid decision expects the full combinatorial auction format (Option D) to apply to the T-4 CY 2024/25 capacity auction and endure for subsequent auctions. Within Option C the clearing of any marginal inflexible offer or alternative higher priced offers based on Net Social Welfare will be made after any offers cleared to meet locational constraints have been selected, and the additional capacity selected for locational reasons will be taken into account in the Net Social Welfare calculation. In the medium term, also in line with the SEM Committee decision SEM-16-081, the Capacity Market Code (in F.8.5.1) provides for the enduring solution of Option D, a mixed integer combinatorial optimisation approach, subject to activation of this enduring approach (in sections M.4 and M.6).

Prior to the implementation of Option D, the methodology for clearing offers to satisfy the Locational Capacity Constraints and inflexibility constraints on the basis of Net Social Welfare is based on Option C. This is referred to here as the Interim Auction Solution Methodology as it combines M.4 (Interim Auction Solution) and M.6 (Alternative Auction Solution Methodology) of the Capacity Market Code. M.4 relates to offers that are cleared based on the unconstrained auction used in the determination of the price and M.6 relates to the rules-based alternative to a mixed integer programming approach that is used to deal with inflexibility constraints and locational capacity constraints.

The Interim Auction Solution Methodology begins with Interim Auction Solution described under M.4 of CMC, where all offers scheduled in the determination of the Auction Clearing Price are cleared, except for a Price Setting Offer that is Inflexible. Then the Interim Auction Solution Methodology clears

[63] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-081%20CRM%20Locational%20Issues%20Decision%20Paper.pdf

additional “out of merit” offers only to serve locational capacity constraints and to address “lumpiness” (i.e. inflexible offers that exceed the quantity required).

The Interim Capacity Auction Methodology is subject to a set of requirements in M.6.1.7 of the Capacity Market Code. In particular, in accordance with M.6.1.7.(d), the Interim Auction Solution Methodology, “shall provide for limits, specified by the System Operators, on the number of combinations of solutions for Inflexible price-quantity pairs the subject of Capacity Auction Offers considered … so as to allow the methodology to reach a solution within the Allowed Timeframe”. Under the Interim Auction Solution Methodology described here, when seeking to maximise Net Social Welfare, a subset of inflexible offers not cleared is considered (rather than all inflexible offers not cleared) in order to ensure that the auction can solve within the Allowed Timeframe.

The Interim Auction Solution Methodology set out in this document implements the requirements of the Capacity Market Code set out in F.8 as modified by the Interim Auction Solution set out in M.4 and the Alternative Auction Solution Methodology set out in M.6.

A.3 TSOs Proposed AASM

Initial Clearing

In accordance with paragraph F.8.4.4(c), a price-quantity pair with a price less than the Offer Price Clearance Ratio of the Auction Clearing Price shall be cleared to its scheduled quantity as determined in accordance with paragraph F.8.3.2.

In accordance with section F.8.3 - Determination of the Auction Clearing Price, where a tie exists for the Price Setting Offer, the offers will be scheduled in the following order of priority: Clean, higher Net Social Welfare, lower Maximum Duration and finally randomly.

Locational Capacity Constraints

Figure 10Figure 10illustrates a set of offers that contribute to satisfying a Locational Capacity Constraint. Some of these offers are already cleared by the Initial Clearing Process. The following process is applied to identify a set of feasible solutions involving different combinations of inflexible offers to be considered further.

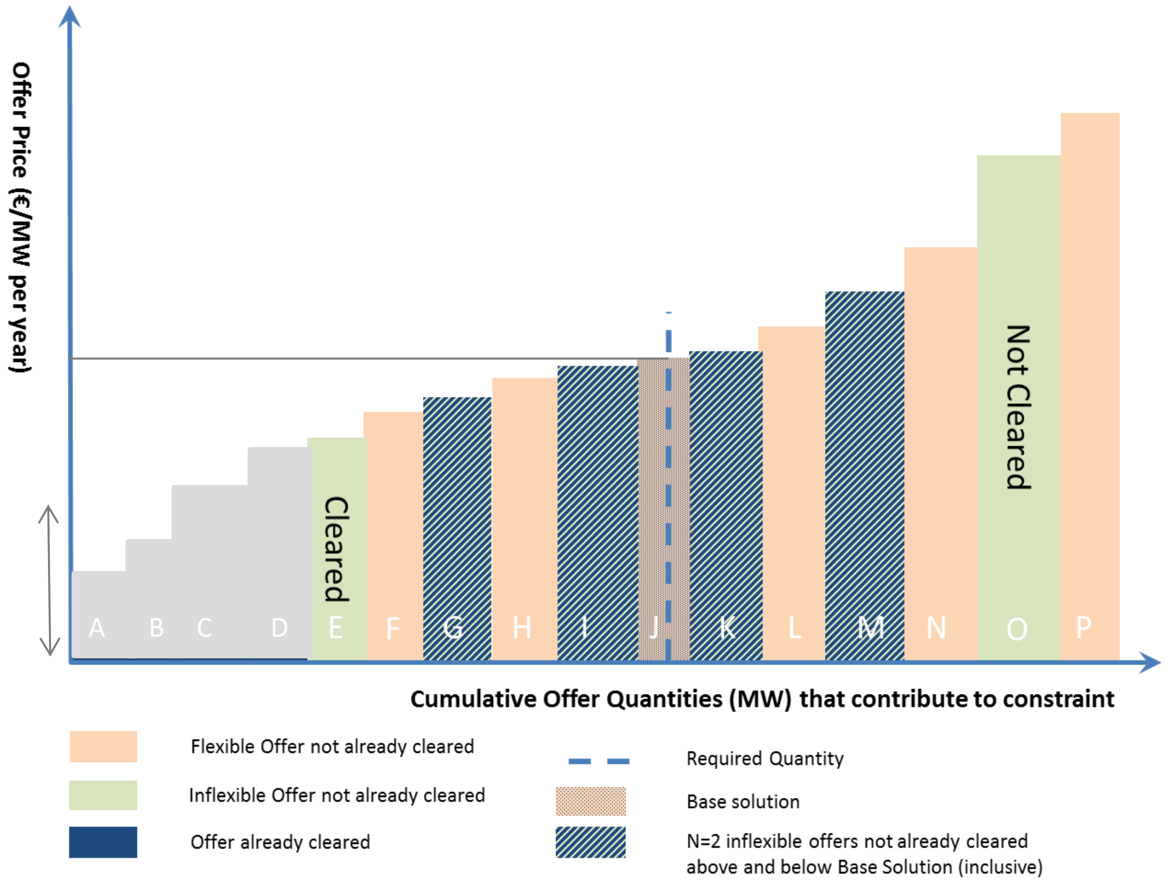

Figure 10: Identifying feasible solutions based on subset of inflexible offers not cleared for N=2

For each Locational Capacity Constraint, the following steps are followed for all feasible solutions already determined in that Locational Capacity Constraint:

1. Determine the base solution (the marginal offer that meets the requirements of the constraint when inflexibility constraints are relaxed). In Figure 10, this is offer J, which is a flexible offer. This can also be an inflexible offer.

2. Where two or more offers have the same price (i.e. there is a tie), schedule offer pairs in the following order: clean, flexible, quantity (lesser quantities first), duration (shorter durations first), random.
3. Where available, select next N inflexible offers not cleared above base solution (inclusive). Where available, select next N inflexible offers not cleared below base solution (inclusive). These offers represent the subset of inflexible offers not cleared to be considered further[64]. Where a tie exists, the approach in step 2 applies. In Figure 10, N=2 and the subset of offers to be considered is G, I, K and M.

[64] Where the base solution is flexible, this subset would be comprised of 2N inflexible offers not cleared. Where the base solution is inflexible, this subset would include the base solution and would therefore be comprised of 2N-1 inflexible offers not cleared.

4. Inflexible offers not cleared below this subset are cleared. Inflexible offers not cleared above this set remain not cleared. In Figure 10, offer E is cleared and offer O remains not cleared on this basis.

5. Determine allowed solutions for every combination of subset of inflexible offers not cleared subject to offers on same CMU being scheduled in order. Based on offers set out in Figure 10, 16 combinations of the four inflexible offers are possible. They are G, I, K, M, GI, GK, GM, IK, IM, KM, GIK, GIM, GKM, IKM, GIKM and "none".

6. For each allowed solution, schedule allowed flexible offers not cleared in order of increasing price as required to cover any remaining shortfall. Based on offers set out in Figure 10, combination GIKM would not require any flexible offers to be schedule, whereas the combination of none of the inflexible offers would require F, H, J, L and N (partially).

7. Check feasibility of allowed solution: (a) it meets the Required Quantity and (b) it does not exceed the Required Quantity by more than an entire offer quantity. Based on offers set out in Figure 10, all combinations would be feasible.

8. Record feasible solutions to take forward to processing next step of auction.

Repeat for all Level 2 Locational Capacity Constraints and then for all Level 1 Locational Capacity Constraints.

Inflexibility Constraints and Final Solution

Once a set of feasible solutions that satisfy all the Locational Constraints has been identified, associated offers are cleared for each feasible solution and the Net Social Welfare of each feasible solution is calculated.

For each feasible solution, if the Price Setting Offer is an inflexible offer not cleared, an approach similar to Section 0 is applied to determine if the Net Social Welfare can be improved as follows:

1. Determine the base solution as the inflexible Price Setting Offer.

2. Where available, select next N inflexible offers not cleared above base solution (inclusive). Where available, select next N inflexible offers not cleared below base solution (inclusive). These offers represent the subset of inflexible offers not cleared to be considered further. Where a tie exists, the approach in step 2 applies.

3. Inflexible offers not cleared below this subset are cleared. Inflexible offers not cleared above this set remain not cleared.

4. Determine allowed solutions for every combination of subset of inflexible offers not cleared subject to offers on same CMU being scheduled in order.

5. For each allowed solution, schedule allowed flexible offers not cleared in order of increasing price where they increase the Net Social Welfare of the allowed solution.

6. The feasible solution is updated with the allowed solution with greatest Net Social Welfare. Where there is no allowed solution with a greater Net Social Welfare, the feasible solution is not updated.

The final solution is the feasible solution (updated accordingly as set out above) with the highest Net Social Welfare from the set of feasible solutions identified in section 2.2 (as modified by this section). Where there is a tie between scheduled offers in the final solution in accordance with F.8.4.6 of the Capacity Market Code, the relevant offers are cleared in accordance with F.8.4.7 of the Capacity Market Code.