Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism (CRM)

Parameters for T-4 2022/23 Capacity Auction

Decision Paper

SEM-18-155

28 September 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 Capacity Year (CY) 2018/19 T-1 Auction took place in December 2017. Following the completion of the CY2018/19 auction, 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-18-030 the SEM Committee decided on the parameters for the T-1 CY2019/20 auction. The purpose of this decision paper is to set out the decisions in relation to:

- The parameters for the CY 2022/23 T-4 auction;
- Enduring aspects of the CRM design including those areas for which interim arrangements have been put in place; and
- Specific changes to the CRM auction design to comply with terms of the EC State aid decision.

The assessment criteria to inform decisions is set out in Section 1.3 and is consistent with that used for the CRM detailed design.

The decisions within this paper follow on from the associated consultation (SEM-18-028) which closed on 26 June 2018. Eighteen responses were received to the CRM T-4 CY2022/23 consultation. All non-confidential responses to the consultation (SEM-18-028) have been published on the SEM Committee website.

Summary of Key Decisions

The SEM Committee has made the following decisions:

- Transmission constraints (Section 2):
    - To reflect transmission constraints in the CY2022/23 T-4 auction;
    - To choose Option 1 in relation to multi-year pay-as-bid Reliability Options in Local Capacity Constrained Areas. This maintains the status quo of allowing the possibility of multi-year pay-as-bid Reliability Options only where there are no other solutions available to satisfy the minimum MWs in the constrained area;
- Auction format (Section 3). To implement Auction Format C for the CY2022/23 T-4 auction (Alternative Auction Solution Methodology as described in Appendix A) in order to ensure compliance with State Aid decision commitments;
- Capacity Requirement (Section 4):

- To reflect a measure of operating reserve in the demand curve for T-4 auctions. The level of reserve to include will be no less than 100MWs, and no more than 500MW at the all-island level. The exact level will be defined in the Final Auction Information Pack;
- To keep the 8-hours LOLE standard unchanged for CY2022/23;

- Administered Scarcity Pricing (Section 5):
  - To set full Administered Scarcity Price equal to 25% of VoLL from the start of CY2022/23;
  - To set VoLL on an October to September year, rather than the current calendar year basis;

- Auction volumes and demand curve (Section 6):
  - To defer a decision on the proportion of the Capacity Requirement to hold back from the T-4 capacity auction to the T-1 auction. The deferred decision applies both to the withholding at the All-Island level, and for LCC minimum MWs;
  - To use a different shape of demand curve for the CY2022/23 T-4 auction (Option B), to the shape used in transitional auctions. The curve continues to slope at volumes below the Capacity Requirement, as illustrated in Figure 5;

- Auction Price Caps (Section 7):
  - To set the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auction for CY2022/23. Given the revised estimates of the BNE Net CONE, APC for the CY2022/23 T-4 auction will be set at €138.45/kW/year; and
  - To set the ECPC at 0.5 x Net CONE for CY2022/23. Given the revised estimates of the BNE Net CONE, APC for the CY2022/23 T-4 auction will be set at €46.15/kW/year.

- Derating factors (Section 8): The RAs have updated the estimates of the GB interconnector factors. The EMDF for GB remains at 60%, and the outage factors are unchanged from the consultation document.
- New Capacity Investment Rate Threshold (Section 9): remains at €300/kW.

Related to the issue of reflecting a measure of operating reserve in the demand curve for T-4 auctions, the RAs intend to carry out a supplemental consultation regarding the inclusion of reserves in constrained regions (Local Capacity Constraint Areas as defined in the CMC). This supplementary consultation is due to be published shortly.

Contents

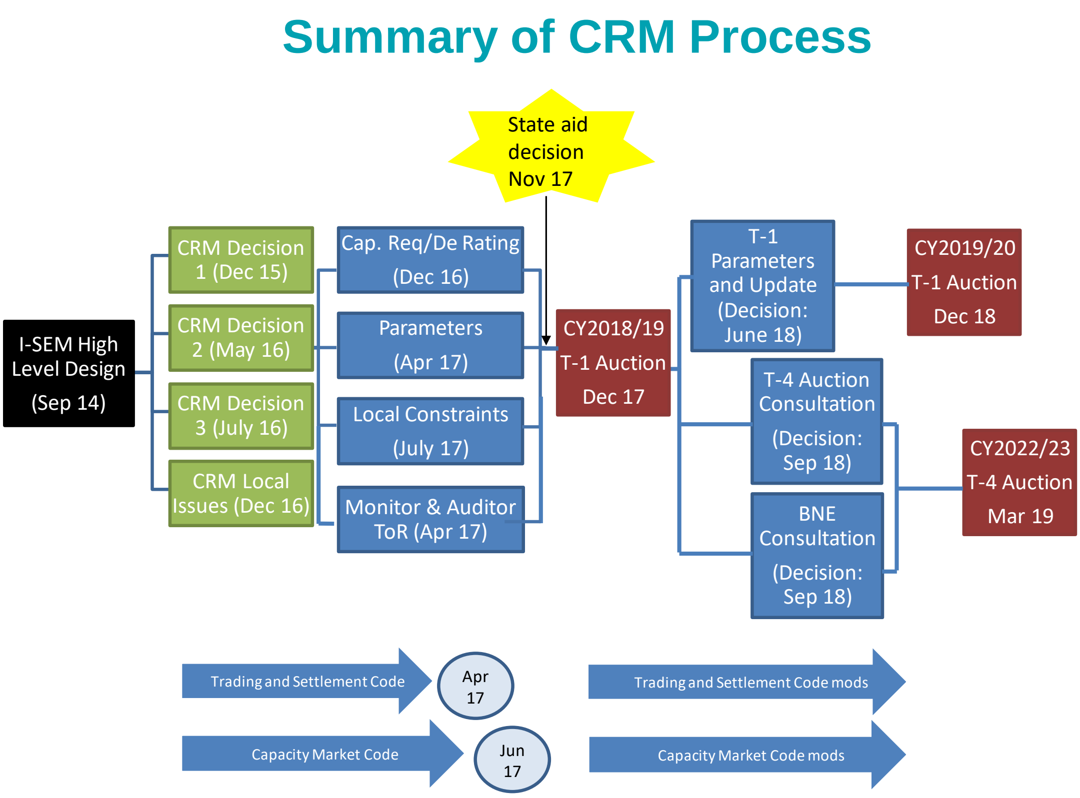
1. OVERVIEW

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[1]. 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. The first T-4 auction for CY2022/23 is planned for late March 2019, as set out in the capacity auction timetable published on the SEMO website.

1.1.6 The SEM Committee published the CRM Parameters for T-4 2022/23 Capacity Auction paper (SEM-18-028) on 14 May 2018. The purpose of this paper is to consult on:

- The parameters for the first T-4 capacity auction parameters for CY 2022/23;
- Decision on enduring aspects of the CRM design including those areas for which interim arrangements have been put in place;
- Specific areas of the CRM auction design in light of the updates mentioned above.

1.1.7 This document sets out the decisions following the SEM-18-028 consultation.

1.1.8 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 was consulted upon separately by the SEM Committee within the CRM T-4 Best New Entrant consultation (SEM-18-025)[2]. The decision SEM-18-156 on the BNE/Net CONE is a key driver in setting the following auction parameters for the T-4 capacity auction:

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

1.1.9 This decision paper and the T-4 BNE/Net CONE decision will inform the T-4 CY2022/23 Initial Auction Information Pack due to be published shortly after the SEM Committee has published these decision papers.

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

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

1.2 RESPONSES TO CONSULTATION

1.2.1 This paper includes a summary of the responses made to the CRM T-4 2022/23 Capacity Auction Parameters consultation paper (SEM-18-028) which was published on 14 May 2018.

1.2.2 A total of 18 responses to the consultation were received. These respondents are outlined below. One of these submissions was marked private and confidential, another submission had separate parts which were marked private and confidential.

- AES
- Aughinish Alumina Ltd
- Bord na Mona
- Bord Gais Energy
- CEWEP
- Deputy Dooley FF
- ESB GWM
- Eirgrid SONI
- Eirgrid interconnector
- Energia
- Grange
- Moyle interconnector Ltd
- Power NI Energy PPB
- SSE
- Tynagh
- UL – Dr R Lynch
- 3cea

1.3 ASSESSMENT CRITERIA

1.3.1 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.

1.3.2 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 INTRODUCTION

2.1.1 In the CRM Locational Issues decision (SEM-16-081), the SEM Committee decided to reflect transmission constraints in the transitional T-1 auctions, in the context of needing to manage the location of plant exit. The SEM Committee deferred the decision on whether to reflect transmission constraints in the first T-4 auction, committing in SEM-16-081 to consult again on the pros and cons of including locational constraints at a time closer to the first T-4 auction.

2.1.2 In SEM-18-028, the SEM Committee consulted on:

- Whether to include transmission constraints in the CY2022/23 auction, and
- If transmission constraints are included, whether multi-year pay-as-bid Reliability Options be permitted (other than, if no other solution can ensure minimum MWs are met in a Local Capacity Constraint (LCC) area.

2.2 CONSULTATION SUMMARY

Inclusion of transmission constraints

2.2.1 In SEM-18-028, the SEM Committee consulted on whether to reflect transmission constraints in the first T-4 auction for CY2022/23.

2.2.2 The results of the CY2018/19 auction reflected 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.

2.2.3 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)[3]. This in turn may reduce the need for further management of exit by CY2022/23.

2.2.4 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

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

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

2.2.5 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:

- Uncertainty as to if transmission capacity constraints will be resolved by CY2022/23;
- Uncertainty around the demand growth forecasts;
- Uncertainty around what units may exit by CY2022/23, and the geographical distribution of those awarded in merit Reliability Options may change from year to year;
- Uncertainty around the effect of CO_2 emissions limit of 550g/kWh impacting exit decisions; and
- It is not clear where the most competitive locations for new entry will be.

2.2.6 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.

2.2.7 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.

2.2.8 **SEM-18-028 stated that, 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**, and the SEM Committee sought consultation feedback on that point of view.

2.2.9 The SEM Committee proposed that the CRM T-4 auction system 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.

Multi-year pay-as-bid ROs

2.2.10 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[4].

2.2.11 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*."

2.2.12 Therefore, it was 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. 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.

2.2.13 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.

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[4] 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.*"

2.3 SUMMARY OF RESPONSES

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

2.3.1 Most respondents were in general agreement with reflecting transmission constraints in the T-4 auction. Reasons put forward by respondents included:

- Without an explicit locational capacity requirement, it could be difficult to secure enough capacity to meet the security requirement in localised areas;
- It is not clear that transmission constraints, resulting in the need for localised capacity requirements have been or will be resolved by the 2022/23 Capacity Year;
- There is a continued need to (carefully) manage exit and/or entry in the CY2022/23 via the inclusion of transmission constraints in the CRM auction;
- It 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;
- It was contended that there is a particular threat to the security of supply in the Level 2 Greater Dublin area and contend that a minimum capacity commitment of 2,000 MW is required for capacity year 2022/23 to ensure continuity of supply;
- It is not clear that the North-South transmission constraint will be removed by capacity year 2022/23; and
- Reflecting constraints in the T-4 auction will ensure that, where new entry is required in certain locations, then the auction lead time will facilitate such new entry.

2.3.2 Some respondents did not agree with reflecting transmission constraints in the T-4 auction, variously arguing that:

- In-merit participants of the unconstrained auction should not be disadvantaged by system constraints;
- Long-term customer bills could be increased by the forced closure of efficient in-merit generator units due to grid constraints;
- Locational capacity constraints should be addressed outside the CRM;
- The proposed methodology will result in flawed arrangements that are not a market based solution and will end up failing to provide efficient entry and exit signals;
- Locational issues in I-SEM could be addressed via alternative solutions such as sharpening TLAFs and GTUoS, allowing unrestricted bidding in the Balancing Market or side contracts between TSOs and generators;
- Transmission constraints should be addressed through network upgrades and/or other measures, rather than capacity mechanisms;
- Certain constraint related issued should be addressed by other market based solutions (e.g. voltage support contracts that can be tendered for, by any plant capable of providing these services);
- It is unfair to directly discriminate based on locational constraint in the capacity market;
- The issue of locational constraints is not strictly a capacity market issue i.e. it is not a shortage of capacity problem;

- The recommendation appears to be driven by an inability to have a 'full suite of reforms to locational signals' in place by March 2019; and
- Unconstrained generators are at a huge disadvantage.

2.3.3 One respondent who did not agree with the proposal suggested a two-stage approach:

- Hold an unconstrained T-4 auction initially, for around 60-70% of capacity.
- Hold constrained auctions if necessary later at T-3, T-2 or T-1 stage, after the SEM Committee had had time to conduct a full review of locational signals, and once investors have had the chance to react to the new signals.

They suggested that withholding 30-40% of capacity from the T-4 auction, would mitigate the risk that too little capacity would be procured in certain LCCs at T-4 stage, and that the required capacity could only be procured at a later stage by "procuring extra".

Q. 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?

2.3.4 A number of respondents supported the inclusion of multi-year pay-as-bid Reliability Options to meet the minimum Locational Capacity Constraint requirement. These respondents stated that:

- The results of the T-1 auction highlighted that several existing units could be decommissioned ahead of schedule, potentially leading to a capacity shortage in a constrained area;
- Under the assumption that current installed capacity is not sufficient to meet the localised minimum capacity requirement, new capacity will be required in the short-medium term;
- The proposals support the ability for multiyear ROs to compete against single year ROs provided that they are a cost-effective solution for consumers; and
- There was merit in such an approach as it would introduce greater levels of competition in these areas; and
- Not allowing multi-year bids is effectively excluding new plant from the market, as it is not possible to finance and build a new generation unit without a multi-year capacity commitment.

2.3.5 One respondent who saw merit in the approach cautioned that careful consideration of issues relating to market power and also of the likely duration of the constraint would be important. In this regard, there may be merit in allowing shorter duration multi-year offers to compete out-of-merit to satisfy Locational Capacity Constraints.

2.3.6 A number of respondents stated that prices in multi-year contracts are not directly comparable with prices in single-year contracts, suggesting a long-term contract can be a more expensive solution than a single-year contract with the same price or even a higher one. These respondents stated that the capacity auction will therefore produce inefficient and higher cost outcomes, if the prices bid for multi-year contracts are compared directly with the prices bid for single-year contracts. It was stated there is a very substantive risk of generating stranded assets and costs. It was stated that the price discovery in meeting these constraints should be used to promote locational signals and incentivise the TSOs to remedy the infrastructure.

2.3.7 One respondent raised concerns that a pay-as-bid approach would significantly disadvantage new entrants and in fact may provide a disincentive for the level of new entry needed, to be built. This respondent stated this approach for pay-as-bid is not completely clear and said this approach encourages less transparency in motivating bids as close as possible to the clearing price, and not setting bids reflective of a generator's costs.

2.3.8 Another respondent not in support stated new participants should be allowed bid in for multi-year pay- as- bid Reliability Options, but not confined to a constrained area, and described an example where the North South Interconnector is subsequently built and there is no requirement now for a plant which was successful for locational reasons in NI, the System Operator will be paying out of market payments for 5-10 years.

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

2.3.9 A number of respondents favoured option 1 (as currently in transitional auctions), these stated:

- option 1 should be modified to promote competition and to facilitate comparison of bids. Option 1 should be adapted, so that existing generators can earn the same revenue as new entrants, (1) by allowing all existing generators within a constrained area to bid up to the market-clearing price for single-year offers in that area and (2) to submit multi-year offers as well as single-year offers
- Options 2 and 3 are flawed and will produce inefficient, high cost outcomes. These options will produce biased and costly outcomes in favour of new entry; and
- They consider option 1 to be the only viable option that is economically justifiable. Options 2 and 3 will result in inefficient outcomes as it is impossible to complete a coherent objective assessment of the options without taking account of the duration and where the objective is least cost for consumers then such an assessment would also need to consider total costs including energy, etc.

2.3.10 A number of respondents favoured Option 2 (multi-year offer is priced at or below Net CONE). They described how given the role of the BNE Net CONE, it is difficult to justify procurement at a price above this from a consumer perspective (unless there is no other option and the unit has progressed through the USPC process). Option 3 places potential unjustifiable costs on the consumer.

2.3.11 Some respondents favoured Option 3 (multi-year offer any price up to the Auction Price Cap). Their reasons included:

- They do not believe that placing a cap at Net CONE is the appropriate course of action, overall costs required by a new build unit might genuinely be higher than the Net

CONE. The inclusion of more efficient, new build plant will bring additional consumer savings as would generally be expected to lower the average wholesale market price;

- Investor confidence will only be realised where there is stability and where there is an appropriate balanced risk between the investor and the authorities;
- Considering the APC was set to accommodate the potential forecasting errors for the BNE, multi-year pay-as-bid reliability options should be at any price up to the Auction Price Cap. Application of Option 2 (up to BNE) is excessive regulation considering the APC is meant to address BNE's market power;
- Option 3 is the optimal choice to allow fairer competition between existing capacity providers and new entrants, this would encourage market exit for older inefficient polluting plants; and
- The Option 2 proposal of a 1 x CONE price cap for procuring capacity to solve transmission constraints is effectively a price cap on new entrants in constrained areas which is anti-competitive, when others are allowed bid up to 1.5 X CONE (albeit for a 1 year period).

2.3.12 One respondent favoured option 3, but only if there are no locational constraints. If locational constraints are included then they favour option 1.

2.4 SEM COMMITTEE RESPONSE

Reflect transmission constraints in the T-4 auction

2.4.1 The SEM Committee thinks that it is appropriate to reflect transmission constraints in the first T-4 auction for a number of reasons, agreeing with the majority of respondents in this respect.

2.4.2 Feedback from the TSOs has indicated that the two key existing capacity constraints are unlikely to be resolved by CY2022/23, and that without an explicit locational capacity requirement it could be difficult to secure enough capacity to meet the security requirement in localised areas. In particular, we note that:

- The planned date for the completion of the North-South interconnector upgrade, which would relax the constraint between Ireland and Northern Ireland is now not scheduled for completion until 2023[5].
- Likely load growth in the greater Dublin area is likely to mean that the constraints are likely to persist for a number of years.

2.4.3 The SEM Committee agree with those respondents who suggested that a full review of locational signals is appropriate, but notes that there is insufficient time to complete such a review in time for it to affect the outcome of the first T-4 auction for CY2022/23, which is planned to take place in late March 2019.

[5] See http://www.eirgridgroup.com/site-files/library/EirGrid/Tomorrows-Energy-Scenarios-2017-Locations-Report.pdf page 4

2.4.4 It would be possible to delay the auction, holding a T-3 auction or a T-2 auction for CY2022/23 after a review of locational signals is complete. However, if the auction is delayed beyond the current 3 ½ year lead time, it will increasingly preclude new entry from certain technologies that take a time to build. For any review of locational signals to have meaningful effect, not only would the review need to be complete, but:

- Investors would have to adjust their investment plans to take account of the locational signals. In practice, it is likely to take investors a significant time to adapt their plans, identify sites and obtain necessary planning approvals and connection agreements for the new sites; and
- The TSOs would have to have time to re-plan the development of the transmission system to take account of changes in the location of new capacity and/or demand, and be confident that they can deliver on the required transmission reinforcement.

2.4.5 In practice, delaying any auction for CY2022/23 to such an extent that meaningful changes in locational decisions can be accommodated, is likely to foreclose entry by many technologies, including new CCGTs.

2.4.6 The SEM Committee viewed the proposed two-stage approach (to have an initial unconstrained T-4 auction for limited volume, followed by a later constrained auction once investors have signals to reacted to locational signals) with interest. However, it does not consider this to a viable solution. The benefits are likely to be limited, since by the time investors and the TSOs have reacted to likely signals, it is likely to be too late for a number of technologies to enter. Such proposals would also raise a number of other key risks and issues including:

- A significant volume would have to be withheld from the initial unconstrained auction to the later constrained auction to ensure that we did not "procure extra" – given the undertaking to the EC, not to do so from CY2020/21 onwards.
- Withholding volume from the constrained auction may create issues for existing generators. Participation is currently mandatory for existing non-intermittent generators, to prevent the exercise of market power. Withholding a significant amount of volume from the initial unconstrained auction could artificial depress the clearing price if participation remained mandatory, or create market power issues if the mandatory provisions were relaxed.
- Such an approach, which would entail major changes to policy decisions and the CMC may prove very difficult to implement in such a tight timeline.

2.4.7 The RAs note that some respondents argued that reflecting transmission constraints in the T-4 auction disadvantaged in-merit participants, and was "unfair". The SEMC notes that if transmission constraints persist, then the location of capacity needs to reflect those constraints. Incremental capacity in over-supplied areas has little additional value to consumers, and they should not be expected to pay for it. Furthermore, as part of the State aid undertaking to consumers, the authorities have undertaken not to "procure extra" capacity in respect of transmission constraints from CY2020/21 onwards. Those respondents who argue that the CRM auctions should ignore transmission constraints and should procure capacity to deal with transmission constraints are effectively asking the SEMC to "procure extra" capacity.

Inclusion of multi-year pay-as-bid Reliability Options

2.4.8 The SEM Committee has taken the view that, on balance, at the current time, the risk of "stranded" multi-year pay-as-bid Reliability Options outweighs the risk of repeatedly contracting for high priced one year Reliability Options from existing generators.

2.4.9 The SEM Committee has therefore decided to stick with the current rules (Option 1), whereby multi-year pay-as-bid Reliability Options can only be awarded to auction participants who are in-merit on an All-Island basis, unless there is no other way of meeting an LCC minimum MW.

2.4.10 For instance, the North-South interconnector upgrade is currently projected to be complete some time in 2023. Let us assume that we know with reasonable certainty that the upgrade will be complete by 30 September 2023, and that the completion of the upgrade removes the constraint. On that basis, we could expect Northern Ireland to be a separate Level 1 LCC in CY2022/23, but not thereafter. Option 2 would have allowed a new entrant to obtain a multi-year contract to obtain a Reliability Option for CY2022/23 to CY2031/32 at Net CONE, i.e. at price of €92.30/MWh. If the interconnector upgrade is then completed as expected, Northern Ireland would then cease to be an LCC from the start of CY2023/24, and there is a risk that consumers would be required to pay a price which is above average clearing prices for the remaining 9 years of the Reliability Option, i.e. to pay the cost of a "stranded" contract.

2.4.11 The "failsafe" still exists to cover the eventuality that that several existing units could be decommissioned leading to a capacity shortage in a constrained area. In such a case, where the minimum MW could not be met any other way, provisions still exist to permit a multi-year contract.

2.5 SEM COMMITTEE DECISIONS

2.5.1 The SEM Committee have decided to reflect transmission constraints in the T-4 auction CY2022/23.

2.5.2 The SEM Committee have decided to choose Option 1 in relation to multi-year pay-as-bid Reliability Options. This is consistent with the transitional auctions, allowing the possibility of multi-year pay-as-bid Reliability Options, only where there are no other solutions available to satisfy the minimum MWs in the constrained area.

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 T-1 transitional auction.

3.1.2 The two key changes were being proposed for the T-4 auction in SEM-18-028:

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 was to ensure compliance with the State aid commitments not to over procure. The CY2022/23 T-4 auction will be the first auction for which this change applies; and

b) A change required to the "winner determination" approach to allow multi-year pay-as-bid Reliability Options, at a price up to Net CONE. However, this change was only relevant if we made a change to allow multi-year pay-as-bid ROs. As explained in Section 2, the SEM Committee has decided not to make any changes to the treatment of pay-as-bid ROs, so this change is no longer relevant.

3.1.3 No changes were 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.

3.2 CONSULTATION SUMMARY

Background

3.2.1 A background was provided of previous key auction design decisions made in:

- CRM Decision 3 (SEM-16-039) regarding bid structure, managing lumpiness and process for managing tied bids;
- CRM Locational Issues consultation paper (SEM-16-052) options included:
  - Option B: Simple sealed bid with locational capacity secured additional
  - Option C: Simple sealed bid with "heuristic-based" second step to offset additional locational capacity secured
  - Option D: Full combinatorial
- CRM Locational Issues 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

- As enduring solution implement Auction Format Option D

3.2.2 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). 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.

Proposed auction format

3.2.3 The auction format Option B 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.

3.2.4 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.

3.2.5 The CRM Locational Issues consultation (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:

- 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.

3.2.6 SEM-18-028 provided a worked example of the CY 2018/19 format and illustrated the effect of proposed changes using auction format Option C heuristic format to reflect required changes by State Aid decision.

3.2.7 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.

3.2.8 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 previously 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.

3.2.9 The TSOs would 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.

3.2.10 The TSOs proposals for the updated AASM which defines the detail of the heuristic auction format (Option C) are set out in Appendix A.

3.2.11 The RAs had reviewed the TSOs proposals and stated in SEM-18-028 that they were 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 SUMMARY OF RESPONSES

Q. 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?

3.3.1 A number of respondents had no objection to moving to Auction Format C, stating that:

- They were happy to move to Option D as an enduring solution, but of the options proposed still prefer Option B;
- The format reflects the need to avoid future procurement of out of merit capacity in addition to in merit capacity;
- They agree with the necessity of the proposed changes to the auction format and the development work for the changes is planned to commence in Q4 2018 to be completed in time for the T-4 auction in March 2019; and
- This is the logical approach to follow and in-line with the state-aid decision to send an appropriate market exit signals where surplus capacity is located.

3.3.2 A number of respondents raised concern with Auction Format C citing:

- They think the change will bias the selection of capacity towards multi-year contracts, i.e. in favour of new entry, even when the new entry prompted by multi-year contracts would be inefficient and would raise costs for consumers, relative to using existing capacity;

- There is also nothing to demonstrate the integrity of the Auction Format C process, there has been no proper impact assessment of a change to Format C;
- It is unfair to directly discriminate on the basis of locational constraints in the capacity market. Locational constraints indicate network issues. These issues should be addressed through network planning and delivery, not the capacity market;
- They stated the consultation paper does not provide sufficient detail on the design of Option C to support a detailed appraisal of the design, and suggest it would be necessary to provide a full draft of the revised capacity market code for both Options C and D in order to identify whether they supported their adoption as currently proposed;
- The auction should be unconstrained, with any constraints being applied in the T-1 Auction. Failing that, the TSO's should have the ability to offer necessary plant a Strategic Reserve Contract. These plant would then be excluded from the market but could be dispatched by the TSO when required; and
- They recognise that while this approach may deliver consumer benefit in the short term, do not believe that it will necessarily deliver the optimum long-term solution.

3.3.3 One respondent urged the SEM Committee to perform the full and comprehensive review of locational signals prior to the T-4 auction. This respondent stated that a T-4 CRM auction without the negative impacts from including locational transmission constraints will provide market participants with an auction that is free of inefficient exit/entry signals.

3.3.4 Another respondent strongly argued a position to retain Auction Format B for as long as there are significant transmission constraints, for which there is no visibility of an alternative position or take-up by new local capacity, for the first T-4 auction.

Q. 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?

3.3.5 A number of respondents had no issue with the AASM stating that:

- They believe that the specification of 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) may be over-complicated at this stage of the process;
- The proposed change to N, i.e. two values to take account of those above and below the base solution, allows for the potential to prioritise those inflexible offers set at below the base solution. This is a sensible approach and fairer than the alternative, which would provide a highly complex and risky scenario where the likelihood of being displaced by other offers, is less certain;
- They believe that the proposed AASM is reflective of the objective of providing for displacement of in-merit units with out-of-merit constraint area located units;
- The suggest that the net social welfare function of the AASM should effectively recognise that if a constraint is expected to be in situ for a short period of time, displacing a unit in the auction results in order to accommodate more expensive but

locationally better situated units, may not be the most efficient outcome from a consumer cost perspective;

- They agree with the RAs' suggestion that two separate N parameters (N1 for the number of offers below the base solution, N2 for the number of offers above the base solution) should be investigated;
- Careful consideration needs to be given to the number of combinations to be considered for each stage of algorithm calculation;
- They suggest setting the Offer Price Clearance Ratio such that offers that are considerably less than the clearing price are automatically cleared. The risk of displacement of such "deep-in-the-money" offers is reduced in the case of Auction Format C due to the use of a limited set of combinations. Nevertheless, the Offer Price Clearance Ratio would reduce the likelihood of non-intuitive outcomes; and
- They accept the RO and TSO advice that it will enable solving of the auction scenarios without running an infinite number of solutions.

3.3.6 One respondent stated based on the existing detail available in Appendix A, believe the proposal is flawed in at least two ways. Firstly, it is unclear from the SEM Committee's description in Appendix A how the mechanism would take account of contract duration when selecting bids (proposed mechanism does not prioritise shorter-term contracts in meeting constraints). Secondly, the SEM Committee proposes to select the efficient plant to meet constraints using a calculation of Net Social Welfare that does not accurately reflect the costs and benefits of selecting offers from constrained plant.

3.3.7 Another respondent stated that the consultation paper does not provide any impact assessment of this approach. In the absence of such an assessment and also analysis showing the impact on the potential outcomes with different values for "N1" and "N2" would be necessary to enable informed consideration and comment.

3.3.8 One respondent stated they disagreed with the proposed AASM, suggesting this mechanism to support constraints is flawed, it is simpler to design the T-4 Auction correctly so that it is an enduring solution and facilitate a T-1 auction that can also resolve constraints if required.

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

3.3.9 Respondents largely reiterated views expressed in Section 2 and above, about whether multi-year pay-as-bid Reliability Options should be accommodated. Since the SEM Committee decided in Section 2 not to make any changes to the treatment of multi-year pay-as-bid Reliability Options, discussion of consequential auction format changes is no longer relevant.

3.4 SEM COMMITTEE RESPONSE

Auction Format C for the CY2022/23 T-4 auction

3.4.1 Following decisions made in Section 2 to implement transmission constraints in the T-4 auction, this question focussed on how to implement transmission constraints whilst complying with the State aid undertakings not to "procure extra" in respect of transmission constraints from CY2020/21 onwards.

3.4.2 The SEM Committee notes that a number of respondents had no objection to moving to auction format C, citing how this design is in-line with the State-aid decision and meets locational requirements. The SEM committee agrees with these views.

3.4.3 A number of respondents supported retaining the approach based on auction format Option B, but this approach has to be ruled out as it will not deliver compliance with the State aid undertaking not to "procure extra". Auction format Option C seems the only practical approach to implementing the State aid undertaking, given that the TSOs are not able to deliver the target solution (auction format option D) in time for the first T-4 auction.

3.4.4 However, some respondents answered the question be re-iterating their views that locational constraints should not be reflected in the T-4 auction, and/or suggesting that alternative means be used to meet locational requirements . The SEM Committee addressed these comments in Section 2, and does not propose to repeat its responses here..

3.4.5 One respondent raised concerns with auction format C suggesting change will bias the selection of capacity towards multi-year contracts. As set out in section 2 the SEM Committee has decided to stick with multi-year Reliability Option 1, 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, which reduces the relevance of these comments. However, this criticism reflects a misunderstanding of the differences between auction format C and auction format option B. Auction format option c favours capacity in under-supplied Local capacity constraint areas over those in over supplied areas, but is neutral between single and multi-year Reliability Option, by not taking option duration into account.

3.4.6 A number of respondents requested additional information on auction format C, suggesting sufficient detail had not been provided. These respondents requested a proper impact assessment of a change to auction format C and full draft of the revised capacity market code for both Options C and D. The SEM Committee set out the proposed auction format C in detail in the consultation paper (SEM-18-028), this was both in section 3 and in the Alternative Auction Solution Methodology (AASM) set out in Appendix A. Examples were provided to show the effects of the proposed changes in the auction format on possible outcomes in different circumstances. The detail provided in the consultation sets out the functioning of the proposed auction format. Any auction format policy design decision made by the SEM Committee will be represented in the

CMC where appropriate, consistent with how the CMC was developed (falling out of the CRM detailed design policy decisions). Also, any changes/modifications to the CMC would have to be subject to scrutiny and passed through the CMC modification process. For these reasons, the SEM Committee believes that sufficient information has been presented, and that an appropriate process has been followed.

AASM for the CY2022/23 T-4 auction

3.4.7 The AASM sets out the detail of how auction format option C would be implemented. The SEM Committee notes that a number of respondents had no issue with the AASM as drafted and presented in Appendix A of SEM-18-028.

3.4.8 A number of respondents commented on the two N parameters proposed by the RAs. Some respondents believed it was a sensible approach, some agreed two separate N parameters should be considered/investigated, one respondent suggested it may be over-complicated at this stage of the process.

3.4.9 In light of the State aid requirements to ensure that the auction does not procure additional capacity in respect of transmission constraints the RAs view the revised specification to allow the auction system to consider whether to accept/reject the N1 inflexible offers above and the N2 offers below the marginal inflexible offer as a sensible approach.

3.4.10 As set out in the consultation paper (SEM-18-028) the TSOs will propose a value for N1 and N2 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.

3.4.11 One respondent suggested the AASM should recognise if a constraint is expected to be in situ for a short period of time, to prevent the inefficient displacement of a unit in order to accommodate more expensive but locationally better situated units. The SEM Committee see challenges in trying to determine the exact duration of locational constraints, with a certain level of uncertainty and external factors affecting these.

3.4.12 One respondent raised the issue of “deep-in-the-money” offers being displaced leading to non-intuitive outcomes, suggesting setting the Offer Price Clearance Ratio such that offers that are considerably less than the clearing price are automatically cleared. This respondent also mentioned how this risk is reduced in the case of Auction Format Option C due to the use of a limited set of combinations, compared to Auction Format Option D. The SEM Committee notes the Offer Price Clearance Ratio value remains in the CMC, and the SEM Committee retains the power to determine an Offer Price Clearance Ratio value for a specific capacity delivery and notify that value to the TSOs, and publish it in the Final Auction Information Pack.

3.4.13 One respondent stated that they believe that the proposals are flawed stating it is unclear the mechanism would take account of contract duration when selecting bids; and secondly the proposal to select efficient plant to meet constraints using a calculation of Net Social Welfare does not accurately reflect the costs and benefits of selecting offers from constrained plant. During the detailed design phase, the SEM Committee considered how to compare contract offers of different lengths, and rejected approaches which made more complicated trade-offs between contracts of different durations when selecting bids. At the time, the SEM committee noted that such approaches were complicated to solve, and that few if any capacity auctions weighted offers based on duration. This remains the case. Moreover, this criticism applies equally to all of the options B, C and D. As set out in section 2 the RAs favour staying with Option 2, 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, which limits the extent to which multi-year offers can displace single year offers.

Proposed change to the format to accommodate multi-year pay-as-bid Reliability Options

3.4.14 In Section 2, the SEM Committee decided that multi-year pay-as-bid Reliability Options should only be accommodated where there are no other ways in which to meet the minimum MWs in a Local Capacity Constraint Area. There is no change of policy, therefore no consequential changes are required to the auction format.

3.4.15 One respondent suggested change to rule around tied bids, proposing that bids being ordered first by duration (from shortest to longest), ranked by price for each duration, and then selected by reference to the other criteria ("clean, flexible, quantity") only if is there is a tie. The proposed change is not a required, and not a direct or necessary consequence of any changes to the policy around treatment of multi-year pay-as-bid Reliability Options. This proposed change would only affect winner determination for offers which are at the margin. In practice, this is likely to have an effect only in relative rare cases where offers in the same are tied, and at the margin and have different durations. Whilst the SEM Committee may consider this change at a later stage, it is not significantly likely to be material to prioritise it as a systems change for the first T-4 auction, given time constraints.

3.5 SEM COMMITTEE DECISIONS

3.5.1 The SEM Committee have decided to implement Auction Format C for the CY2022/23 T-4 auction (Alternative Auction Solution Methodology as described in Appendix A) in order to ensure compliance with State Aid decision commitments. This reflects the change if out-of-merit volumes need to be procured to satisfy locational constraints, this will displace in-merit generation elsewhere.

3.5.2 The SEM Committee observe that the Interim Auction Solution, as set out in section M.4 of the CMC, does not permit the displacement of in-merit generation (see M.4.1.6) as required by the State aid decision and to implement Auction Format C – though this is permitted in the main body of the code as set out in F.8.4.4(c). The RAs will propose a modification to M.4.1.6 as soon as possible to go through the modifications process set out in the Capacity Market Code with the intent that this change is effective for the CY2022/23 T-4 auction.

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:

- In CRM Decision 1 (SEM-15-103), where the SEM Committee decided to retain the existing (8-hour LOLE) all-island security standard; and
- In the Capacity Requirement and De-rating Factor decision (SEM-16-082) the SEM Committee decided that operating reserve will not initially be included in the CR; pending further evidence from the TSOs supporting the need for such inclusion.

4.1.2 In making these decisions, which applied to the first CY2018/19 transitional auction, the SEM Committee was mindful that a number of factors would apply in CY2018/19 which would be likely to lead to procurement of capacity significantly in excess of the Capacity Requirement. This decision was vindicated by the results of the CY2018/19 auction, where a total of 1,054MW of Reliability Options were awarded in excess of the adjusted[6] CR.

4.1.3 However, the SEM Committee decided to consult again on the approach to inclusion of operating reserves in the CR, and on the LOLE standard, recognised that:

- A number of the factors which led to procurement significantly in excess of the CR in CY2018/19 would not necessarily apply in a T-4 auction;
- There was more evidence on the direction of travel on the harmonisation of EC capacity requirements since the original decisions had been taken;
- 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, which provided more concrete evidence on incidences of lost load.

4.2 CONSULTATION SUMMARY

4.2.1 SEM-18-028 reviewed moves to harmonise EC standards before discussing the pros and cons of including different measures of reserves in the CR and then discussing whether to tighten the LOLE standard.

Harmonisation of EC capacity requirements

4.2.2 The latest planned Energy Package[7] includes a proposed Energy Regulation[8] 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

[6] Adjusted for non-participating capacity
[7] Typically referred to as the Clean Energy Package
[8] 2016/0379 (COD)

the ISEM. The current draft of this Regulation has been prepared for negotiation with the European Parliament during 2018.

4.2.3 Whilst no harmonised standard has emerged as yet, the analysis showed that:

- The direction of travel is generally to include a measure of operating reserve in the CR. However, 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. 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;
- Whilst not significantly outside EC norms, a number of EC countries have tighter standards in setting their CRs, including surrounding countries in the I-SEM Regional Security Co-ordination area, CORESO, including GB, France and Belgium.

Reserves and the capacity requirement

4.2.4 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.

4.2.5 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, which can be up to 500MW- the maximum import capacity of the EWIC interconnector. Whilst the CR is currently calculated as the level of capacity which delivers a maximum of 8 hours when available capacity exceeds demand, in practice the TSOs operate the system in a different way.

4.2.6 In practice, the TSOs may engage in “demand control”, i.e. controlled load shedding before the level of available capacity is equal or less than demand. They engage in “demand control” 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. The RAs understanding that circumstances in which “demand control” actions may be taken will vary, but as a rule of thumb, “demand control” will be actioned when the level of available operating reserve falls below 100MW.

4.2.7 The following options were considered 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.

LOLE standard

4.2.8 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. The most likely options, if there is any standardisation are:

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

4.2.9 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.

4.2.10 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.

4.2.11 SEM-18-028 evaluated the implications of the different options for including operating reserve / LOLE standard against the I-SEM design criteria.

4.3 SUMMARY OF RESPONSES

Q. 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?

4.3.1 The majority of respondents supported incorporating some measure of operating reserves in the capacity requirement. Responses favoured a wide spread of the options, with no clear consensus on the amount of operating reserve that should be included. Some respondents stated that they consider it appropriate to consider reserve scarcity as a loss-of-load event, as the risk of load shedding at these times is significant.

4.3.2 The majority of respondents supported the tightening of the LOLE standard (reducing LOLE target), with a lot of these respondents favouring a shift to a 3 hour LOLE standard to bring in line with neighbouring markets and EU harmonisation. Some other respondents stated:

- Tightening of the LOLE should also have an inverse impact on the ASP. If the LOLE is being tightened, it would suggest the ASP should be increased;
- Considering the increasingly pivotal role electricity has in society and the economy, they believe that a higher security standard is in the interest of consumers and that a tighter LOLE might deliver an appropriate trade-off between cost and reliability.

4.3.3 Some respondents recognised that that including operating reserves in the capacity requirement and tightening the LOLE standard have broadly the same effect, and argued that implementation of some measure of operating reserves or tightening the LOLE should be done, but it was necessary to do both. For instance, a number of respondents noted that inclusion of 250MW of operating reserve is broadly equivalent to the 3 hours LOLE. One respondent stated that the addition of 444MW should also allow the 3-hour LOLE standard to be met in practice. Another respondent favoured an overall increase of 400-450MW of operating reserve.

4.4 SEM COMMITTEE RESPONSE

Operating reserve

4.4.1 The SEM Committee sees merit in including a measure of operating reserves in the Capacity Requirement. In particular, the SEM Committee recognises that the way that the Capacity Requirement methodology is currently specified requires the inclusion of some measure of operating measure of operating reserves to deliver the LOLE standard in practice.

4.4.2 With an 8 hour LOLE standard, the existing methodology calculates the minimum derated MWs that will deliver no more than 8 hours where demand exceeds available capacity. The existing methodology does not take into account the fact that in practice, the TSOs will undertake "demand control" actions when available operating reserves falls to such low levels that that it considers that the consequences of voluntary demand control are less detrimental than the very likely consequences of involuntary load shedding. These "demand control" actions result in actual instances of unserved energy, and are instances of lost load which are not picked up in the LOLE calculation. A measure of operating reserve needs to be included in the Capacity Requirement to adjust for the fact that the LOLE calculation does not take account of "demand control" actions which occur when available capacity is only slightly more than demand.

4.4.3 The TSOs have indicated that as a rule of thumb, they would typically expect to undertake demand control actions when the surplus of available capacity above demand falls as low as 100MWs, but that the precise value is not codified, and that it may depend on system conditions. Furthermore, there is little or no operational history of such demand control actions, given the fact that available capacity has significantly exceeded the Capacity Requirement (and hence demand) over the last decade.

4.4.4 The SEM Committee notes that there is a strong case for including at least 100MWs of operating reserve in the All-Island Capacity Requirement in the T-4 auction, and that there may be a case for including a larger measure of operating reserve. However, the SEM Committee does not accept the argument that any instance where there is insufficient available capacity to meet the target reserve constitutes a lost load event and should be treated as such in calculating the Capacity Requirement. Whilst it is true that any occasion when available capacity is less than 500MW in excess of demand increases the risk of unserved energy, it does not necessarily result directly in unserved energy. The Capacity Requirement should be strongly rooted in an analysis of the costs and benefits to consumers- the costs of additional capacity versus the saving in the opportunity cost of unserved energy (valued at VoLL per MWh of unserved energy).

4.4.5 Given that the SEM Committee has now decided to reflect transmission constraints in the T-4 auction, it is also considering whether it is appropriate to reflect a measure of operating reserve in the Level 1 and Level 2 Local Capacity Constrained Areas, as well as the All-Island Capacity Requirement. This issue will be considered in a separate supplementary consultation due to be published shortly.

4.4.6 The SEM Committee notes that if, following this supplemental consultation it decides that it is appropriate to include a measure of operating reserves in the Local Capacity Constraint Areas, this decision, rather than the decision on the All-Island Capacity Requirement may drive actual auction outcomes. If, for instance, following the supplemental consultation the SEM Committee considers that it is appropriate to include 100MW of reserve in the Northern Ireland minimum MW and 100MW of reserve in the Dublin minimum MW, in practice this is likely to mean procurement of an extra 200MW across the island, even if only 100MW is added to the All-Island Capacity Requirement.

4.4.7 The SEM Committee has therefore decided to defer a decision on the amount of All-Island operating reserve to be reflected in the CY2022/23 T-4 auction and make that decision alongside the decision on how much, if any, reserve to allocate to Local Capacity Constraint Areas in CY2022/23.

4.4.8 Under the terms of the CMC, the TSOs are required to publish the Capacity Requirement within the Initial Auction information Pack (IAIP). The indicative timetable set out in the CMC provides for the IAIP to be published about 24 weeks before the date of the auction. Given the requirement to publish the IAIP at around 24 weeks in advance of the auction to allow Qualification and Exception Application process to begin, the SEM Committee approved the CY2022/23 T-4 auction IAIP without the inclusion of any measure of operating reserve in the All-Island Capacity Requirement. The IAIP was then published on 28 September 2018

4.4.9 However, the SEM Committee has powers under CMC to adjust the All-Island demand curve after the publication of the Capacity Requirement[9]. In the CY2018/19 transitional T-1 auction the SEM Committee used those powers to adjust the demand curve to take account of non-participating capacity[10]. The SEM Committee intends to use those powers to adjust the All-Island demand curve for the CY2022/23 T-4 auction to also adjust the demand curve to include the appropriate measure of All-Island reserve[11] to achieve the same effect as if it had been included in the Capacity Requirement published on 28 September 2018.

LOLE standard

4.4.10 The SEM Committee has decided to not change the 8-hours LOLE standard for CY2022/23.

4.4.11 The updated review of EC harmonisation of standards does not show a clear single LOLE/LOLP standard. Whilst some surrounding countries such as GB and France have tighter standards (lower LOLE targets), the 8-hour standard is by no means an outlier on an EC wide basis.

4.4.12 There is no new evidence that the Value of Lost Load (VoLL) to consumers on the island of Ireland is inappropriate. With the estimate of the cost of incremental capacity (Net CONE) in SEM-18-156 increasing by about 12% rather than reducing, there is no clear evidence base to justify the tightening of the LOLE standard. At an 8-hour standard (with the inclusion of an appropriate measure of operating reserve), the evidence suggests that the incremental cost of capacity (Net CONE = €92.30/MWh) approximately balances the incremental saving in expected unserved energy, when valued at VoLL.

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[9] The SEM Committee approves the Capacity Requirement approximately 6 months before an auction as part of approving the Initial Auction Information Pack

[10] Capacity which is not mandated to participate in the auction (intermittent renewables), but which is able to provide a measure of capacity and has chosen not to participate in the auction

[11] And to make other adjustments to withhold capacity from the T-4 auction to the T-1 auction for DSU participation and demand forecast uncertainty, as discussed in Section 6

4.4.13 The SEM Committee notes that the EC State aid decision specifically references the inter-relationship between the LOLE standard, VoLL and Net CONE, noting that "*To ensure the correct trade-off between costs and security of supply, the authorities calculated the actual value that consumers place on additional security of supply (the value of lost load or VOLL) and compared that with the costs of additional security of supply (the cost of the so-called 'Best New Entrant' plant, i.e. a peaking plant that would just cover its fixed costs if its annual running hours were the same as the LOLE). On that basis, the authorities explain that the estimated VOLL corresponds to an 8-hour LOLE*"…

4.4.14 This SEM Committee may change the LOLE in future, if there is any clear evidence of a change in relevant assumptions (VoLL, Net CONE, or the estimated incremental saving in MWh of unserved energy resulting from a tightening of the LOLE standard). Alternatively, the SEM Committee may change its view if there is consistent evidence of new entry at a capacity price significantly less than estimated Net CONE (as has been the case in GB).

4.5 SEM COMMITTEE DECISIONS

4.5.1 The SEM Committee has decided to keep the 8-hours LOLE standard unchanged for CY2022/23.

4.5.2 The SEM Committee has decided to reflect a measure of operating reserve in the demand curve for T-4 auctions. The level of reserve to include will be no less than 100MWs, and no more than 500MW at the all-island level. However, the final decision on the precise measure to include in the All-Island demand curve will be taken following the supplemental consultation regarding inclusion of reserves in constrained regions (Local Capacity Constraint Areas as defined in the CMC).

4.5.3 The IAIP for the CY2022/23 T-4 auction which was published on 28 September 2018, did not reflect any measure of reserve in the Capacity Requirement. The Capacity Requirement for any given auction is fixed at the IAIP stage. However, the SEM Committee will use it powers under the CMC to direct the TSOs to adjust the demand curve included in the FAIP to reflect the decision on the level of reserves to include at All-Island level made following the supplemental consultation.

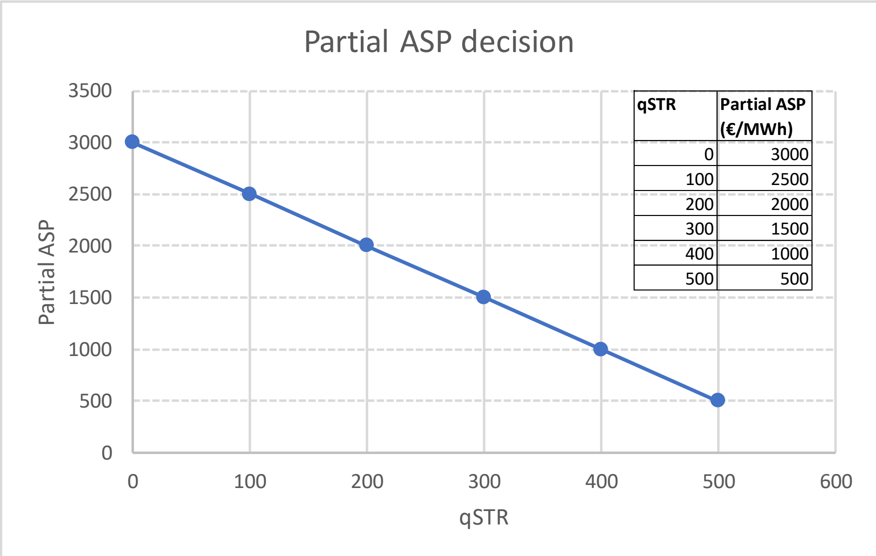
5. ADMINISTERED SCARCITY PRICING PARAMETERS

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 2.

Figure 2: Administrative Scarcity Price as function of available operating reserve (qSTR)



5.1.2 The SEM Committee stated that:

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

5.1.3 In SEM-18-028 the SEM Committee consulted on the value of the ASP function to apply from CY2022/23 onwards, in order to help market participants to price their offers into the CY2022/23 T-4 auction.

5.2 CONSULTATION SUMMARY

Background

5.2.1 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 (€3,000/MWh) or a market determined price[12]. The market determined price can rise as high as VoLL[13], set at €11,128.26/MWh in 2018[14].

5.2.2 SEM-18-028 provided a wider context in arriving at the proposed options, discussing :

- 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.

Proposed options:

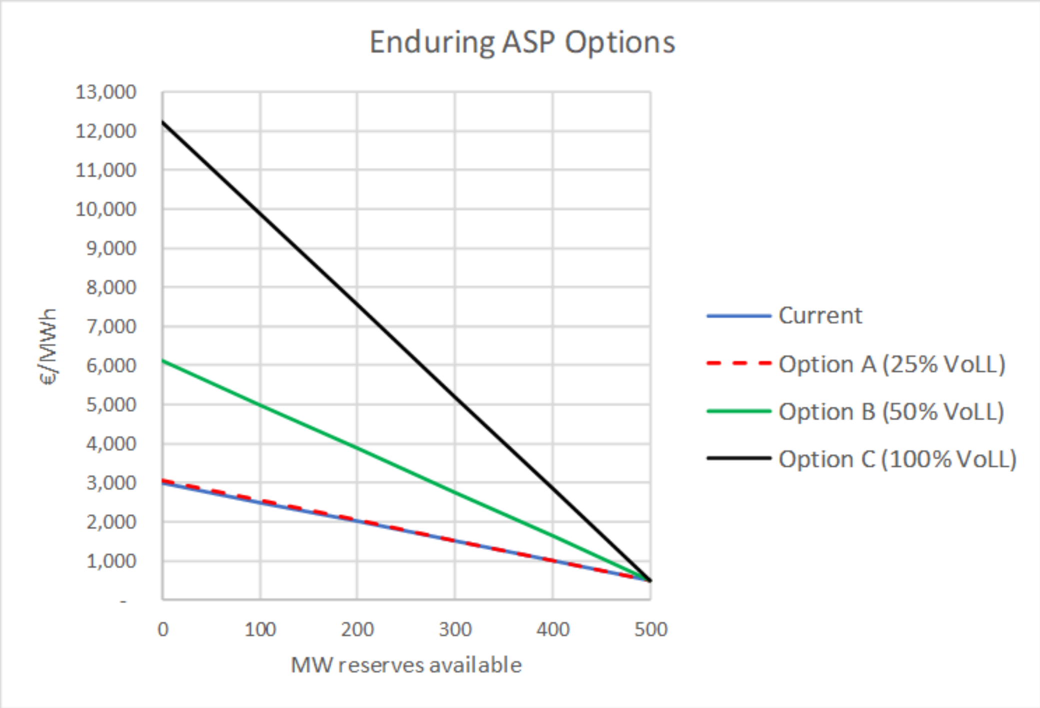
5.2.3 SEM-18-028 considered three options for the value of Full ASP following the transitional period (i.e. commencing at the start of CY2022/23):

- Option A: 25% of VoLL, likely to be around the current level of €3,000/MWh in CY2022/23, depending on inflation[15];
- 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.

5.2.4 These options are shown in Figure 3, which assumes that the Partial ASP function continues to be a straight line (one-piece linear) function, like the current (transitional) function.

[12] 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.
[13] 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.
[14] 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
[15] 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 3: ASP function options



Factors determining the enduring ASP function value

5.2.5 SEM-18-028 evaluated these proposed options in setting the enduring ASP function against the below relevant factors:

- 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; and
- Sending exit signals to unreliable plant.

5.3 SUMMARY OF RESPONSES

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

5.3.1 The majority of respondents favoured 25% of VoLL (approx. €3000/MWh) (option A) for the value of Full ASP. Reasons given included:

- Full ASP greater than 25% would put additional financial risk on the system's generation during both a transition to ISEM and as the island's energy markets transition to a larger renewable and intermittent generation footprint;

- Setting it anywhere near VoLL overlooks the role of ASP as a price floor in the balancing market and its role in signalling availability and DSR through high prices during scarcity. Such signals do not require prices near VOLL to incentivise reactions;
- Caution against big step changes in ASP levels that would undermine regulatory certainty, heighten perceived market exposure, and shake investor confidence;
- The most prudent approach is to retain the value of the Full ASP at €3,000/MWh until market participants have greater experience of balancing market to manage this risk;
- There is no operational experience of I-SEM yet and therefore any supporting evidence to increase the current ASP value. Consideration cannot therefore be given to increasing Full ASP towards higher levels of VoLL until a liquid, transparent, and fully functional set of markets exist. This includes an IDM, secondary market for ROs, and forward contract market.
- The impact of exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity and appropriate stop loss limits are not yet proven; and
- Although the equivalent of full ASP in GB is moving to £6000/MWh, that price is a cap, unlike ASP in SEM which is a floor.

5.3.2 A number of respondents favoured 100% of VoLL (option C), reasons include:

- This is the most efficient option, and sharpens the incentives for generators to be available at times of scarcity. It strongly promotes system security while rewarding generators with higher energy prices for being available in times of need; and
- The intention of the SEM Committee during CRM design was to move to VOLL after the transition period.

5.3.3 One respondent favoured option B a full ASP of 50% of VoLL as it seems likely that the ACER consultation, not yet complete, would likely correspondingly increase the Euphemia Day-Ahead price above its current €3,000/MWh to €6,000/MWh. This would provide better alignment on pricing between Ireland and GB.

5.3.4 One respondent clarified that the value of Full ASP does not apply to the Capacity Auction, it applies in the Balancing Market under section E.4 of the Trading and Settlement Code. Where the RAs wish to apply a higher Full ASP, it is important that their decision is specified in the terms set out in the TSC to ensure that the values can be enforced.

5.3.5 One respondent stated that tightening of the LOLE should have an inverse impact on the ASP. If the LOLE is being tightened, they suggest that the ASP is increased.

5.3.6 One respondent suggested that before addressing the issue of full ASP there needs to be a review of the risk associated with each generator. The risks are not equal amongst all generation as those plants behind a constraint will be dispatched by the TSO, however those plants who are not behind a constraint are exposed to potential errors on the part of the TSO.

Q. 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?

5.3.7 All respondents to this question support setting VoLL on an October to September year, rather than the current Calendar Year basis, some of these stated that:

- The key benefit of this proposal is that ASP will not change part way through a Capacity Year and therefore provides a greater level of certainty for CRM participants when participating in the capacity auctions; and
- It makes sense and its availability for calendar years is unlikely to be major complication for participants.

5.4 SEM COMMITTEE RESPONSE

Value of the ASP function

5.4.1 The SEM Committee is persuaded that the risks of materially increasing the value of full ASP above €3,000/MWh outweigh the benefits. At the time of decision making (the September SEM Committee meeting), the ISEM has not yet gone live, and market participants have no practical experience of the ISEM, its operation and the operation of ASP.

5.4.2 The SEM Committee recognises that Options 2 and 3 could create greater uncertainty for investors, and could have a material impact on capacity market offers and hence consumer bills.

5.4.3 The SEM Committee has therefore decided to adopt Option A for CY2022/23.

5.4.4 The SEM Committee feels comfortable in making this decision, knowing that the ASP function is a floor price, not a maximum price- as recognised by a number of respondents. Therefore, in scarcity, prices may still rise to provide efficient incentives on price responsive load, and to attract inflows into the ISEM through interconnectors, supporting system security.

5.4.5 Maintaining the floor price at this level remain compatible with existing moves to harmonise EU electricity market prices, which typically relate to maximum prices not minimum prices.

5.4.6 Whilst the SEM Committee is persuaded that Option A remains appropriate at this stage of the development of the ISEM, the SEM Committee does not preclude a move to Option B or C in the medium term. The SEM Committee sees merit in the arguments of certain respondents that Option B or Option C would sharpen the incentives to perform and provide an efficient exit signal for unreliable plant. Therefore, once we have more operational experience of the ISEM and ASP, including managing mitigating arrangements such as the socialisation fund, it may be appropriate to increase the values of the ASP function.

VoLL on an October to September year

5.4.7 The RAs note that all respondents to the question supported setting VoLL on an October to September year basis (capacity year), citing the benefit that ASP will not change part way through a capacity year and therefore provides a greater level of certainty for CRM participants when participating in the capacity auctions.

5.4.8 The SEM Committee favour a move to setting VoLL on an October to September year, rather than the current Calendar Year basis, so that a single value of VoLL value pertains to a particular capacity year.

5.5 SEM COMMITTEE DECISIONS

5.5.1 The SEM Committee has decided to adopt ASP Option 1, with the value of full ASP equal to 25%of VoLL, effective from 1 October. The actual value of full ASP will be dependent on the value of VoLL set by the SEM Committee for CY2022/23, closer to the time. VoLL for Calendar Year 2018 was set at €11,128.26/MWh in SEM-17-071.

5.5.2 For the purposes of the CY2022/23 T-4 auction USPC setting process, which will occur in Q3 2018 and Q4 2019, the SEM Committee will use an assumed value of ASP, calculated by projecting forward the existing VOLL based on a 2% inflation assumption. However, actual VoLL, and hence the actual value of full ASP in CY2022/23 is likely depend outturn inflation between now and CY2022/23, although the SEM Committee does not preclude conducting a fundamental review of VoLL between now and CY2022/23.

5.5.3 The SEM Committee has decided to set VoLL on an October to September year, rather than the current calendar year basis, so that a single value of VoLL value pertains to a particular capacity year. This change will take effect from the start of CY2020/21. During the remainder of the transitional period it will have no effect on the value of full ASP (which will remain fixed at €3,000/MWh), but is an input into the Capacity Requirement calculation.

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 0 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 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.

6.1.4 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. The experience of the CY2018/19 auction was that the participation of DSU increased substantially, with a total of 619MW of de-rated DSU capacity qualified for the first auction (8.8% of the total Capacity Requirement) and 548 MW being successful (7.8% of the Capacity Requirement). Therefore, in SEM-18-028, the SEM Committee consulted on whether it is appropriate to withhold a larger proportion of the Capacity Requirement back from the T-4 auction to the T-1 auction for CY2022/23.

6.1.5 In SEM-18-028 we also consulted on a potential change in the shape of the demand curve (relative to the shape employed in the transitional T-1 auctions).

6.2 CONSULTATION SUMMARY

Proportion of capacity requirement to withhold from T-4

6.2.1 SEM-18-028 evaluated the range of volume to be withheld from T-4 auctions, in light of key considerations including:

- The higher DSU participation in the I-SEM CRM compared to the SEM;
- The extent to which demand side response is able to compete at T-4 stage; and
- Facilitate the participation of environmentally friendly demand side response.

6.2.2 SEM-18-028 discussed how 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. A key assumption is that there are many technologies which can enter the market if they are given a four year lead time, but little new capacity that can enter with only a one year lead time.

6.2.3 Conversely, the risk of withholding to little capacity from the T-4 auction is that DSUs cannot compete in T-4 timescales, because end consumers (on whom DSUs rely to deliver the demand side response) can commit to delivering demand response four years ahead, due to lack of certainty over their business plans.

6.2.4 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.

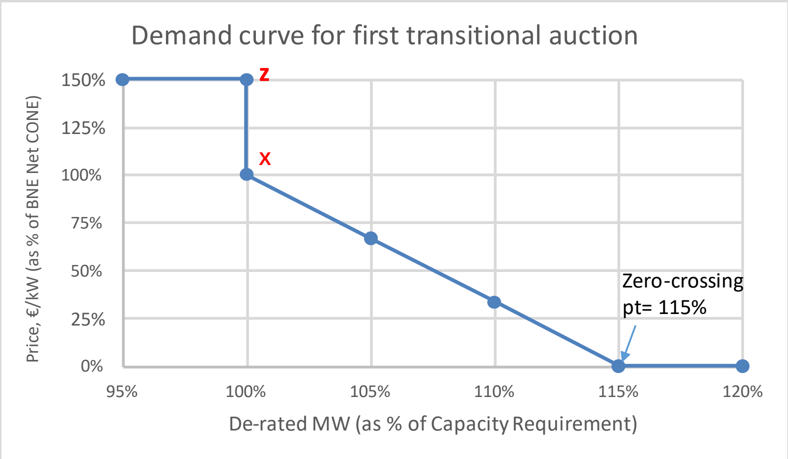
6.2.5 The SEM Committee considered the following options:

- 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.

Shape of the demand curve

6.2.6 In CRM Decision 3 (SEM-16-039) the SEM Committee decided on a shape and positioning for the demand curve in the transitional auctions. The shape of the curve in the transitional auction is shown in Figure 4 below.

Figure 4: Demand curve for transitional auctions



6.2.7 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.

6.2.8 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.

6.2.9 The SEM Committee therefore considered two options for the CY2022/23 T-4 demand curve shape and position:

- 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 **Error! Reference source not found.**;
- Option B: 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[16] in the T-4 auction we will aim to buy commensurately more in the T-1 auction[17].

6.2.10 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, as well as a number of other adjustments discussed in this document. The final demand curve will then be published in de-rated MW terms in the Final Auction Information Pack.

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[16] 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 **Error! Reference source not found.**.

[17] (or may hold T-3 or T-2 auctions if appropriate

6.3 SUMMARY OF RESPONSES

Q. 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?

6.3.1 The majority of respondents did not support holding back increasing the proportion of the capacity requirement from 5% to 7.5%, reasons included:

- Evidence from the PJM markets in the US would contradict statement in consultation paper that the experience of the US market has been that it is difficult for DSUs to compete at the T-4 stage;
- They believe the auction should be technology neutral and DSUs should not be getting favourable treatment. An auction that withholds capacity for a specific type of technology is biased and creates inequitable treatment for participants;
- Any increases in demand over forecast allied with holding back of capacity would leave the market at serious risk of the T-1 auction being incapable of fulfilling the capacity requirement. The proposal exposes the grid and consumers to an unacceptable risk of power shortages if insufficient capacity is available in the existing fleet (given that no new investment can be reasonably expected to participate in a T-1 timeframe);
- It is more prudent to wait until more experience of DSUs participation in the T-4 auctions is acquired rather than withholding capacity for DSUs;
- Withholding demand whilst forcing supply imposes excess supply, could cause the T-4 auction price to be permanently depressed, whilst the T-1 price could be permanently elevated by the lack of capacity able to enter the later auction. 5% of the CR is the equivalent of c350MW which is broadly a CCGT unit and withholding this demand will both distort the price and may send inappropriate closure signals. Increasing the amount held back to 7.5% will just serve to make the outcomes more distorted and ultimately less competitive by artificially depressing the prices in the T-4 auctions even further, sending stronger closure signals that may not be efficient and potentially creating un-competitive T-1 auctions;
- Uncertainty of availability is not limited to DSUs, since many generators are unsure of their availability in four years' time;
- In practice, many DSUs are aiming to provide capacity by installing small back-up generators that are fossil-fired (specifically, distillate- or diesel-fired). These DSUs would not offer any environmental benefits over capacity that is formally provided by generators;
- They favour a cautious approach, suggesting setting withholding at the lower end of the range (5%), since it could reasonably be assumed that many generating units which are unsuccessful in the T-4 auction will have closed by the time of the T-1 auction, limiting options other than DSUs at the T-1 stage; and
- Withholding should not be increased unless constraints are not in T-4, in which case it would be appropriate to hold back the additional 2.5% for the T-1 auction. While

there is an argument that DSU participation will increase by CY2022/23, there is nothing to prevent DSU's from participating in the T-4 auction as in GB.

6.3.2 A number of respondents were in favour of increasing the proportion of the capacity requirement to hold back above 5%. The reasons included:

- They believed that DSU participation should be well in excess of 7.5;
- Providing for excessive volumes in T-4 auctions inherently carries more risk given the multitude of uncertainty; and
- The uncertainty that exists four years out in relation to the future demand and the generation portfolio, means that it is prudent to hold back a higher portion of the Capacity Requirement.

Q. 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?

6.3.3 The majority of respondents favour Option 1 (procure the full LCC minimum MW requirement in the T-4 auction), stating that:

- The minimum capacity requirement in each constrained area should not be adjusted for volumes withheld from the T-4 auction to the T-1 auction;
- A prudent TSO will be particularly concerned with securing supplies in advance within constrained areas. Withholding demand from the T-4 auction will undermine the TSOs' ability to do so;
- Withholding capacity from a T-4 auction will distort the pricing and send erroneous closure signals to capacity that may actually be required. This may be even more critical in relation to constrained areas where the options to resolve those constraints in the T-1 timeframe may be even more limited and therefore the risk of inefficient outcomes is even greater; and
- They do not think a zonal minimum could be forecast accurately, given the limited historical data of DSU penetration levels available, and given the uncertainty of how DSUs will respond to the T-4 auctions.

6.3.4 A number of respondents saw merit in either option 2 or 3, where a component of the minimum MW requirement for a Locational Capacity Constraint is held back for inclusion in the T-1 Capacity Auction. One of these respondents suggested a compromise could be appropriate whereby historic DSU participation would be used, but up to a maximum of e.g. 5%.

6.3.5 One respondent favoured option 3 stating it is more likely to reflect market conditions and thereby to lead to a more secure and efficient solution. It is more efficient than option 2 by being market specific, and that the unnecessary purchase of expensive capacity some four years out far outweighs the certainty – as represented under option 1.

6.3.6 A number of respondents who oppose the inclusion of capacity constraints in the T-4 auction, also opposed withholding capacity at a locational level.

Q. 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?

6.3.7 A number of respondents favoured option B, stating that:

- If less than the Capacity Requirement is bought in the T-4 auction commensurately more can be purchased in the T-1 auction, with a more efficient outcome. It allows the auction to buy less if capacity is expensive and hold off for the T-1 auction; and
- Option B is also more stable from a pricing perspective as it does not feature any vertical sections. Vertical sections may give rise to large price jumps for small changes in Awarded Capacity.

6.3.8 A number of respondents favoured option A (same shape demand curve as in first T-1 auction), stating that:

- Option B would likely over-procure and over-pay capacity particularly given uncertain exit levels, demand levels and DSR at the long-term auction stage;
- Proposed Option B is not a prudent approach for ensuring the security of supply is achieved. The purpose of the T-1 auction should be to procure any additional capacity requirements due to changes in demand forecast and any remaining capacity that didn't clear in the T-4 auction, not as an additional auction that can be used to artificially lower the capacity requirements in the T-4 auction;
- The consequence of Option B is to again defer procurement from the T-4 auction to the T-1 for the same capacity year;
- They favour Option A as intrinsically more stable and predictable, because it is tied to known parameters;
- It was impossible to appraise – or to apply – demand curve option B, since it is simply not defined. The Consultation Paper shows a sloping line in figure 9, but the position of the sloping line is not defined by reference to any fixed points;
- It is difficult to comment on option B as the curve is not defined but merely shown as a line on Figure 9. There is no rationale to justify and define the start and end points of the line or whether the line is just arbitrarily selected;
- ; and
- The diagram presented is misleading and suggests that option B will cut the x axis at 120%, there is nothing in the accompanying text to support this.

6.3.9 Some respondents argued that Option B was insufficiently determined since the brown line in the diagram (Figure 9 in SEM-18-028) is shown shifted to right and above the blue line. However, the extent to which it is shifted is not determined in the diagram, or in the text.

6.4 SEM COMMITTEE RESPONSE

Proportion of capacity requirement to withhold from T-4

6.4.1 The SEM Committee notes that there is considerable change in the level of DSU participation in the All-Island Market and this creates a significant amount of uncertainty- a point raised by a number of respondents. There is uncertainty about the extent to which:

- Trend growth in participation seen in the CY2018/19 auction and during the CY2019/20 Auction Qualification process will continue; and
- DSUs can/will participate in T-4 auctions. Evidence from other markets, such as the PJM market cited provides insights, but nevertheless the composition of demand side response in the ISEM may be significantly different from demand side response in the PJM area.

6.4.2 The SEM Committee notes that:

- It will be able to make a more informed decision, once it has seen how many DSUs seek to qualify in the first T-4 auction; and that
- It does not necessarily need to make an *ex ante* decision on how much volume to withhold at All-Island and at constrained area level before it has seen how much DSU volume Qualifies for the T-4 auction.

6.4.3 The SEM Committee intends to wait and see how much DSU capacity seeks to qualify in the T-4 auction, before deciding how much capacity to withhold from the T-4 auction to the T-1 auction facilitate DSU participation. If a large number of MWs (in relation to the experience of the transitional CY2018/19 and CY2019/20 auctions) of DSU capacity seeks to qualify in the T-4 auction, the SEM Committee will withhold a smaller proportion of the Capacity Requirement back, based on the logic that it has been demonstrated that a large proportion of DSU capacity is able to commit at T-4 stage. If, however, the MWs of DSU capacity seeking to Qualify at T-4 stage is small in relation to the experience of transitional T-1 auctions, this will constitute evidence that DSUs find it difficult to participate at T-4 stage.

6.4.4 This approach mitigates the risks associated with setting a higher withholding percentage ex ante, which were identified by a number of respondents as set out above. The planned approach also incentivises individual DSUs to seek to participate at T-4 stage, since if other DSUs participate at T-4 the withheld percentage will be reduced, limiting their opportunities at T-1 stage. By incentivising T-4 participation where possible, it also seeks to maintain technology neutrality as much as possible, without precluded participation by DSUs that genuinely cannot commit at T-4 stage.

6.4.5 To clarify any supplemental capacity auction for a specific delivery year will be open to all technology types, not just DSU. Any portion of capacity withheld from the original T-4 auction would still be open for all available capacity.

6.4.6 A number of respondents were in favour of increasing the proportion of the capacity requirement to withhold, citing the uncertainty that exists four years out in relation to the future demand, as well as DSU participation rates.

6.4.7 As set out in the consultation paper (SEM-18-028) the SEM Committee view withholding larger volumes from the T-4 auction as mitigating the risk of over-forecasting (since if demand forecasts are subsequently revised downwards, we are not locked into higher volumes). The Least Worst Regrets approach increases the risk of over-forecasting demand, since it has a tendency to select higher demand scenarios.

6.4.8 Demand forecast uncertainty has come into particular focus lately. The 2018 Generation Capacity Statement (GCS) demand forecasts show a considerable increase in the demand forecasts for Ireland in 2022 and 2023 (and hence for the All-Island market) over the equivalent forecasts set out in the 2017 GCS. For instance, the 2018 GCS TER Peak forecast for Ireland in 2023 is around 12% higher than corresponding forecast in the 2017 GCS. There is also approximately an 7% difference between the High Demand scenario and the Median Demand scenario estimates for the TER Peak within the 2018 GCS. Both of these of statistics illustrate the level of demand forecast uncertainty at the current time.

6.4.9 This demand growth in the high growth forecasts is disproportionately driven by forecasts of data centre growth in the Dublin area, with the result that demand forecast uncertainty is significantly higher in Ireland, and particularly in the Dublin area than in Northern Ireland.

6.4.10 The SEM Committee agrees with those respondents that argue that the level of demand forecast uncertainty may be grounds for withholding a larger percentage of capacity from the T-4 auction. The SEM Committee also notes that differences in the levels of demand forecast uncertainty constitutes grounds for withholding different % of the minimum MW requirements in different areas.

6.4.11 The SEM Committee notes that supplemental capacity auctions do not have to be in the form of a T-1 auction, for instance supplemental auctions could be held at the T-3 or T-2 stage. This could be done in a scenario where the expected capacity demand turns out to be higher closer to the time than originally forecast at the T-4 stage.

6.4.12 The SEM Committee has powers under CMC to adjust the All-Island demand curve after the publication of the Capacity Requirement[18]. In the CY2018/19 transitional T-1 auction the SEM Committee used those powers to adjust the demand curve to take account of non-participating capacity[19], and the SEM Committee will do the same for the CY2019/20 T-1 transitional auction.

[18] The SEM Committee approves the Capacity Requirement approximately 24 weeks before an auction as part of approving the Initial Auction Information Pack

[19] Capacity which is not mandated to participate in the auction (intermittent renewables), but which is able to provide a measure of capacity and has chosen not to participate in the auction

6.4.13 The SEM Committee intends to use those powers to adjust the All-Island demand curve for the CY2022/23 T-4 auction to also adjust the demand curve to withhold:

- A percentage of the Capacity Requirement to cover demand uncertainty; and
- An amount to facilitate DSU participation in T-1 auctions.

6.4.14 These are in addition to the adjustments for non-participating capacity, and for the inclusion of a measure of reserve, as discussed in Section 4.

6.4.15 The decisions on the amounts to withhold will be made once the SEM Committee has seen the results of the CY2022/23 Qualification process, and communicated in the Final Auction information Pack.

6.4.16 The CMC does not currently specify precisely analogous powers for the SEM Committee to adjust the minimum MWs for constrained areas to account for appropriate adjustments- it only specifies the ability of the SEM Committee to approve or reject a recommendation. However, the SEM Committee is in the process of putting in place an emergency CMC modification to clarify its powers to adjust Local Capacity Constraint Area minimum MWs.

Shape of Demand Curve

6.4.1 The SEM Committee favours Option B as a shape for the demand curve, as it recognises the value in buying less at the T-4 stage if capacity is expensive, and allows any shortfall to be made up in supplemental auctions.

6.4.2 The SEM Committee notes that a number of respondents argued that the parameters of Option B were not fully defined in SEM-18-028. The value of the zero-crossing point (where the curve crosses the x axis) and the positioning of the line was not fully clear. The SEM Committee favours retain the same value of the zero cross-point, 115% of the Capacity Requirement as used in the transitional auctions and shown in Figure 4. This maintains the same trade-off between capacity and price, when the price is below Net CONE as in the transitional auctions. The SEM Committee favours extending the sloping demand curve backwards in a straight line beyond point x in Figure 4, so that intersects with the horizontal line at 92.5% of the Capacity Requirement. This curve is depicted in Figure 5 below.

6.4.3 The SEM committee notes that a number of respondents favoured Option B (curve continues to slope between the Net CONE value and the Auction Price Cap) precisely for this reason, arguing that it potentially leads to a more efficient outcome.

6.4.4 A number of respondents favoured option A (same demand curve as first T-1 auction) citing reasons such as proposed option B is not a prudent approach, and that Option A is intrinsically more stable and predictable. The SEM Committee recognises that Option A, has less guarantee of procuring at least the Capacity Requirement at T-4 stage, but considers that there are appropriate risk mitigants:

- The risk to security of supply is relatively limited, and the prospect of being able to procure additional capacity at T-3, T-2 or T-1 stage is a sufficient risk mitigant; and
- The fact that we have employed the Least Worst Regrets based approach which tends to set the Capacity Requirement based upon a higher case demand forecast is another risk mitigant.

6.4.5 Given these risk mitigants, the SEM Committee thinks that the following benefits potentially outweigh the risks:

- Not committing to procure capacity at T-4 stage, if expensive, when that capacity may not be necessary if higher case demand forecasts do not materialise; and
- Being able to procure cheaper at T-3, T-2 and T-1 stage if necessary.

6.4.6 The SEM Committee also notes that there is precedent from other global capacity auctions, of employing sloping demand curves which permit the procurement of less than the Capacity Requirement.

6.5 SEM COMMITTEE DECISIONS

Proportion of capacity requirement to withhold from T-4

6.5.1 The SEM Committee has decided to defer a decision on the proportion of the Capacity Requirement to hold back from the T-4 capacity auction to the T-1 auction. The deferred decision applies both to the withholding at the All-Island level, and for LCC minimum MWs.

6.5.2 The SEM Committee will determine the exact amounts to be withheld at the Final Auction Information Pack stage, and the amount withheld may include:

- A proportion of the Capacity Requirement which reflects the level of participation of DSUs seen during the CY2022/23 T-4 auction Qualification process; and
- A proportion of the Capacity Requirement to reflect demand uncertainty.

6.5.3 The SEM Committee may decide to withhold different percentages in the different constrained areas, depending on local variations in both the level of demand uncertainty and the level of DSU participation in those areas.

Shape of the demand curve

6.5.4 The SEM Committee has decided on a version of Option B as the shape for the CY2022/23 T-4 demand curve as illustrated in Figure 5.

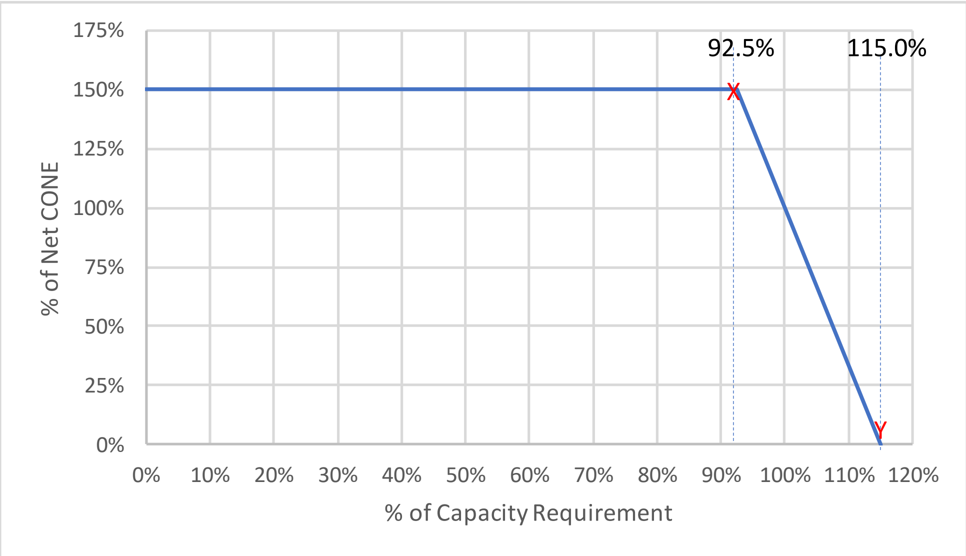
6.5.5 The Indicative Demand Curve shown below is:

- Horizontal at the Auction Price Cap of 1.5 x Net CONE (see decision in Section 7.5) from 0% of the Capacity Requirement to 92.5% of the Capacity Requirement (at point X in Figure 5)
- Slopes down in a straight line from point X to point Y in Figure 5. Point Y is the zero-crossing point at 115% of the Capacity Requirement. The line passes through the point at where the volume is equal 100% of the Capacity Requirement and the price equals Net CONE.

6.5.6 Note that the Indicative Demand Curve shown in Figure 5 will be adjusted for:

- Non-participating capacity;
- Amounts withheld to facilitate DSU participating and to reflect demand forecast uncertainty in accordance with the decision set out in 6.5.2 above; and
- Any capacity already procured in previous auctions for the delivery year in question, via multi-year Reliability Options.

Figure 5: Indicative demand curve, before adjustments



6.5.7 The above adjustments will be calculated by the RAs and approved by the SEM Committee, and communicated to market participants in the Final Auction Information Pack.

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

7.1 INTRODUCTION

7.1.1 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, which was set at 1.5 x Net CONE in the first transitional auctions;
- The Existing Capacity Price Cap (ECPC) for the T-4 CY2022/23 auction, which was set at 0.5 x Net CONE in the first transitional auctions; 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.

7.1.2 In CY2018/19 and CY2019/20 auctions, the BNE Net CONE was set at €82.13/kW/year.

7.1.3 The SEM Committee consulted 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). Following the consultation, the SEM Committee have revised their estimate of the BNE Net CONE to €92.30/kW (see Table 9 of the T-4 Best New Entrant Decision (SEM-18-156)). This represents a 12.3% increase in nominal terms over the CY2019/20 figure, so that keeping the APC and ECPC multiples unchanged at 1.5 and 0.5 respectively would result in an increase in their €/kW/year values of around 12.3%.

7.2 CONSULTATION SUMMARY

Auction Price Cap (APC)

7.2.1 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.

7.2.2 The SEM Committee proposed 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 remained 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 (typically been around 70% of Net CONE in capacity payments in CPM).

Existing Capacity Price Cap (ECPC) and Unit Specific Price Caps (USPCs)

7.2.3 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)[20];
- An Existing Generator which has Net Going Forward Costs (NGFCs) which exceed ECPC can apply to the RAs to obtain a USPC[21].

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

7.2.5 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.

7.2.6 The SEM Committee do 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.

Investment and maintenance

7.2.7 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[22].

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

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

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

7.2.8 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**. SEM-18-028 stated that 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.** SEM-18-028 sought feedback on issues 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

7.2.9 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.

7.2.10 As set out in SEM-17-090, we used the 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.

7.3 SUMMARY OF RESPONSES

Q. 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?

7.3.1 The majority of respondents agree with the proposal to keep the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auction, stating that:

- They feel that the APC at 1.5 x Net CONE for T-4 auctions is sufficient. Some stated that this view is contingent upon the final value of BNE for CY2022/23, while others stated that the response is not contingent on SEM-18-025 (T-4 BNE consultation);
- There is no need to change the logic which was used in setting the original APC; and
- They do not believe that regular changes to this level would be conducive to investor confidence. The final APC should reflect the outcome of the recently consulted upon BNE for CY2022/23.

7.3.2 A number of respondents were of the view that the APC should be set higher than 1.5 x Net CONE, stating that:

- They were concerned that the assumptions used in the proposed BNE Net CONE methodology may lead to a failure in attracting new investment as the 50% margin could be too tight to deliver a new entrant, and the assumptions used in the T-4 auctions have greater chance for error than the T-1 auctions;

- At a general level, there is more uncertainty over future costs and infra-marginal rents, when looking four years ahead, than at a T-1 auction. To ensure that Reliability Options remain compatible with future costs of operation, prices need to include a higher margin for error in the T-4 auction than in the T-1 auction;
- There is a good case for having a factor higher than 1.5 for T-4 auctions to reflect the greater uncertainty;
- APC provides an indication of “headroom” which can provide encouragement for new entry. On this basis, they consider it should be set at a reasonable level, to provide such a signal; and
- APC should be set at 3 times Net CONE. They argued that there have already been announcements of closure for more than 1000MW after the first auction, it is reasonable to assume that new investment will be required by T-4.

Q. 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?

7.3.3 The majority of respondents were not in favour of the proposal to keep ECPC at 0.5 x Net CONE, stating that:

- ECPC at 0.5 x Net CONE combined with energy market bidding controls will restrict existing participants from recovering their true cost of production;
- Forcing participants to consolidate sunk costs as stranded assets will result in short-term gains for consumers but ultimately will be adverse in the long term. 1.0 x Net CONE should be the cap for existing players;
- The approach to setting the ECPC at 0.5 x Net CONE and the USPC calculation, that results in a plant remaining indifferent to opening or closing and not recovering any contribution to its sunk capacity costs, have created a regulated price rather than a market driven price;
- It is necessary to reset ECPC to include the capital requirements of plants going forward. They state that at a general level, there is more uncertainty over future costs and infra-marginal rents when looking four years ahead than at a T-1 auction. There is also greater uncertainty over the level of RO difference payments that the holder of an RO will have to make in four years’ time;
- ECPC should be higher than 50% of Net CONE to reflect both the incorrect pricing and the uncertainty of the RO payments, as well as more general uncertainty of costs and revenues on a T-4 timeframe;
- Capping ECPC at 50% of Net CONE creates a volatile clearing price whereby prices (barring USPCs) are capped at 50% Net CONE only rising above it in a year where New Entry occurs and dropping back to 50% until the next new entry. This profile is very spikey and does not follow price tracks that would normally be expected to increase on the lead up to new entry;

- Following the first T-1 auction, ECPC at 0.5 capturing 75% of plant, suggests that a large proportion of installed capacity is inefficient. This could result in an unintended exit signal to existing useful capacity. This suggests that the ECPC at the current level, is inappropriate for T-4. They are concern whether the time value of money has been incorporated; and
- The value to the system of generation is CONE, this will become more apparent in 2022/23, when the need to ensure that plants are recovering all costs will be far more apparent.

7.3.4 A number of respondents agreed with the proposal to keep ECPC at 0.5 x Net CONE, stating that:

- They believe the new final value of the BNE Net CONE for CY2022/23 is likely to be increased somewhat from the current Net CONE; and
- The value should reflect the outcome of the recently consulted upon BNE for CY2022/23. They support the current policy for the existing capacity price cap with a view to mitigating market power.

Q. USPC setting: Do you agree with the proposed approach for UFI submissions?

7.3.5 A number of respondents did not agree with the proposed approach for UFI submissions, stating that:

- They do not agree with the proposed approach that an UFI cannot be recovered in just one year and being forced to spread the costs over five years:
- They believe the SEM Committee must allow market participants to submit offers, that include UFI costs according to the risk appetite of the participant;
- The UFI mechanism is not fit for purpose in facilitating plant upgrades or refurbishment. They state that they have repeatedly argued in previous submissions that the current rules will continue to discourage refurbishment and plant upgrades unless they allow all significant future investment to benefit from a long-term contract; and
- As they do not agree with the USPC approach they do not agree with the approach for UFI submissions.

7.3.6 A number of respondents agreed with the proposed approach for UFI submissions. One respondent stated it supports stringent monitoring of the USPC and related UFI submissions. Efficient cost outcomes for consumers must be ensured and units, particularly in locational constraint area, must only be permitted to put forward capacity at as competitive a price as reasonably possible.

7.3.7 One respondent proposed that there is more clarity of Unavoidable Future Investment (UFI) eligible costs particularly in relation to the smearing forward of historic costs. Queried what recourse is there for a plant with substantial UFI in CY2019/20 to recover this in the T-4 CY2022/23 auction where there was no USPC made in CY2019/20?

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

7.3.8 A number of respondents agreed with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23, stating that:

- They support it in the current absence of an alternative proposal; and
- 2% p.a. inflation is a standard approach. However, they find it confusing that this appears to be being applied only to USPC (and not to other metrics within the consultation).

7.3.9 A number of respondents did not agree with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23, stating that:

- They would support a proposal that ties auction parameters to independent external sources, such as BOE and ECB projections. However, in relation to costs, there is significant uncertainty over future values four years in advance, which is not captured by a simple index of inflation;
- Inflation is currently running in excess of 3% and the impact of Brexit will likely impact on inflation being higher than the long term target of 2%, suggest 3% p.a. may be a more appropriate projection; and
- The proposed 2% seems very low with the advent of Brexit and the implications for Irish inflation indices.

7.4 SEM COMMITTEE RESPONSE

APC level

7.4.1 The SEM Committee notes that the majority of respondents agreed with the proposal to keep the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auction CY2022/23.

7.4.2 A number of respondents favoured setting the APC at a higher level than 1.5 times Net CONE. The SEM Committee are of the view that a multiple of 1.5 x Net CONE is sufficient to absorb all the uncertainty given that 1.5 multiple contains a 50% margin for uncertainty in setting Net CONE. In setting the APC the SEM Committee were mindful of market power concerns, even though these concerns may be diluted to some extent by the greater potential for new entry in T-4 auctions.

7.4.3 In the CPM capacity providers have been content to provide capacity at an average payment of less than Net CONE (with capacity providers typically receiving around 70% of Net CONE in capacity payments). The SEM Committee view setting the APC at 1.5 times Net CONE as sufficient to continue to provide scope for new capacity while accounting for uncertainty.

7.4.4 The SEM Committee also notes that, with the re-estimation of the BNE Net CONE, this means that the Auction Price Cap will be set at €138.45/kw/year. This is around 12.4%

higher than in the CY2019/20 auction. Given exchange rate (ACPER) in the Initial Auction Information Pack (IAIP) of 0.9478, this equate to £131.22/kW/year. We note that this compares to a price cap in GB of £75/kW/year.

ECPC level

7.4.5 The SEM Committee notes that the majority of respondents (predominantly generators) were not in favour of the proposal to keep ECPC at 0.5 x Net CONE for CY2022/23.

7.4.6 The SEM Committee is conscious in setting the level of ECPC its critical importance in limiting market power of existing generators. Also, the level of ECPC provides a filter to ensure that only those USPC applications which the RAs need to review are scrutinised. The SEM Committee are of the view that setting the ECPC at 0.5 x Net CONE for CY2022/23 strikes an appropriate balance between the objectives of protecting consumers from the potential exercise market power, and not placing an excessive workload on the RAs and market participants.

7.4.7 The SEM Committee also notes that, with the re-estimation of the BNE Net CONE, this means that the Auction Price Cap will be set at €46.15/kW/year. This is around 12.4% higher than in the CY2019/20 auction in Euro terms. Given exchange rate (ACPER) in the Initial Auction Information Pack (IAIP) of 0.9478, this equate to £43.74/kW/year. We note that:

- This represents a 18.5% increase over the CY2019/20 in sterling terms; and
- This compares to a Pricetaker Threshold in GB of £25/kW

7.4.8 A number of participants in favour of increasing the ECPC level cited uncertainty in projecting four years out and the ability to recover their true, sunk, and/or future production costs. We note that USPC applicants will have the opportunity to make submissions as part of the Exception Application process to demonstrate where there are material changes or significant uncertainty with respect to their future production costs, and those submissions will be given due consideration.

7.4.9 However, we do not propose to change our policy with regard to sunk costs. In developing these market power controls the RAs allowed for existing generators to apply for a Unit Specific Price Cap (USPC) in situations where their Net Going Forward Costs (NGFCs) exceed the ECPC. The definition of NGFCs does not allow for the inclusion of sunk costs. The SEM Committee set out its rationale for this approach in full in SEM-17-022 (CRM Parameters decision). The SEM Committee does not view that there has been any material change of circumstances, and does not intend to make any significant policy changes to this approach for the T-4 CY2022/23. We re-iterate, however, that the USPC process allows applicants to include any Unavoidable Future Investments (UFI) within their USPC submissions, with the UFI costs spread over the life of the upgrade/refurbishment.

7.4.10 The SEM Committee notes that a number of respondents agreed with the proposal to keep ECPC at 0.5 x Net CONE for CY2022/23.

UFI approach

7.4.11 The SEM Committee notes a number of respondents did not agree with the UFI approach. These respondents cited how they disagree with not being allowed to recover their full UFI in one year and described the current approach as discouraging refurbishment and plant upgrades (unless allow all significant future investment to benefit from a long-term contract).

7.4.12 The consultation paper (SEM-18-028) set out how the RAs / SEM Committee did not intend to make any significant policy changes to the approach used to the setting of USPCs for the CY2022/23 T-4 auction. The SEM Committee notes that a number of existing generators have re-iterated their concerns about the level of risk which they are required to bear, resulting from the approach of spreading UFI over 5 years in a number of cases. The SEM Committee fully understand that this imposes some risk on investors, and re-iterates that:

- It believes that this is a reasonable risk for investor which is investing less than the NCIRT to bear; and that
- This is the same risk that investor do bear in other markets, such as the PJM market-which has analogous arrangements.

7.4.13 The consultation paper (SEM-18-028) highlighted the how USPCs for CY2022/23 could include any UFI allowances awarded in the decision relating to the CY2018/19 T-1 auction. It also set out that investment plans in respect of CY2020/21 and CY2021/22 would 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.

7.4.14 One respondent queried what recourse is there for a plant with substantial UFI in CY2019/20 (but without sufficient costs to warrant a USPC in CY2019/20) to recover this in the T-4 CY2022/23 auction, if they have sufficient cost to warrant a USPC in CY2022/23. UFIs are defined as future investment costs which must be incurred if the capacity is to be delivered during the Capacity Delivery Year. If the respondent intends submitting an UFI through the USPC process for CY2020/21 (. The SEM Committee notes that this is a similar case to UFI relating to CY 2020/21. Where a market participant is making an unavoidable investment in respect of CY2019/20, but does not have high enough cost to justify a USPC in CY2019/20, a proportion of the CY2019/20 UFI can still contribute to NGFCs in CY2022/23. As part of its CY2022/23 submission, the market participant can submit the details of its CY2019/20 investment project. Suppose for instance, if that project would normally have resulted in a UFI spread over 5 years, that UFI can still be considered as contributing to the CY2022/23 NGFCs, even if its Cy2019/20 NGFCs are too low to justify a USPC in CY2019/20. If, including the carry forward of an appropriate proportion of the CY2019/20 related investment, the applicants total CY2022/23 costs are high enough to justify a CY2022/23 USPC, then credit for its CY2019/20 investment can still be reflected in its CY2022/23.

7.4.15 The SEM Committee notes that a number of respondents agreed with the proposed approach for UFI submissions, favouring continued stringent monitoring of the USPC and related UFI submissions.

USPC inflation rate to use

7.4.16 The SEM Committee notes that a number of respondents agreed with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23. The SEM Committee proposes to use this value, given the absence of longer term Bank of England and European Central Bank inflation projections for either the UK and Ireland, and with 2% being the inflation target (not a forecast) of both the Bank of England and the European Central Bank.

7.4.17 The SEM Committee notes that a number of respondents did not agree with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23, citing current higher rate of inflation, extra uncertainty with Brexit and uncertainty over future values four years in advance, not captured by a simple index of inflation.

Appeal Determination

7.4.18 Following the closure of the CRM T-4 Parameters consultation on 26 June 2018, the Determination was published in relation to the APPEAL PANEL ESTABLISHED PURSUANT TO SECTION 29 OF THE ELECTRICITY REGULATION ACT 1999, AS AMENDED between HUNTSTOWN POWER COMPANY LIMITED and VIRIDIAN POWER LIMITED and the COMMISSION FOR REGULATION OF UTILITIES (the Appeal determination). The Appeal found that "*there is a need for a targeted contracting mechanism or other additional remuneration mechanism to be put in place*".

7.4.19 Following the publication of the Appeal Determination the RAs received further representation in relation to the CRM design and parameters from a number of market participants. These representations were outside the CRM T-4 Parameters process, and were largely confidential in nature. Some of these representations included the relevant stakeholders' own interpretations of the Appeal Determination and how it may or may not affect the auction price controls.

7.4.20 The SEM Committee does not agree with a number of the interpretations of the Appeal Determination, and the extent to which it has material impact on the auction price controls. The SEM Committee also notes that the Commission for Regulation of Utilities intends to contest the decision of the Appeal Determination.

7.5 SEM COMMITTEE DECISIONS

APC level

7.5.1 The SEM Committee have decided to set the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auction for CY2022/23. This means that for the CY2022/23 T-4 auction, the

APC will be set at €138.45/kW/year. The €/kW/year will be converted to £/kW/year at the exchange rate published in the IAIP.

ECPC level

7.5.2 The SEM Committee have decided to set the ECPC at 0.5 x Net CONE for CY2022/23. This means that for the CY2022/23 T-4 auction, the ECPC will be set at €46.15/kW/year. The €/kW/year will be converted to £/kW/year at the exchange rate published in the IAIP.

UFI approach

7.5.3 The SEM Committee do not intend changing the policy approach to UFIs, for CY2022/23 and favour maintaining the current approach (as used in first two T-1 capacity auctions for CY2018/19 and CY2019/20). However, the implementation of the UFI approach will take appropriate account of investment in UFI in the intervening years between now and the start of CY2022/23.

USPC inflation rate to use

7.5.4 The SEM Committee have decided 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. 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.

8.1.2 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.

8.1.3 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.

8.2 CONSULTATION SUMMARY

CY2022/23 Inputs

8.2.1 For the consultation, the demand input to the determination of the I-SEM Capacity Requirement was based on GCS demand for 2023[23]. This suggested an increase of approximately 60MW over the level used in the CY2019/20 T-1 Auction 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.

8.2.2 The historic interconnector outage rates are determined based on the most recent 10 years of historic data using data to the end of June 2017.

8.2.3 For the consultation, the assumptions for the GB market were derived from NGC's 2017 Future Energy Scenarios (FES).

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

Indicative results

8.2.4 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[24] by 2022/23. Values were also 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%.

8.2.5 The RAs saw 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 proposed retaining the EMDF value of 60% used in CY2018/19 and CY2019/20 for CY2022/23. However, this position was to be reviewed when the analysis was refreshed for the Decision paper based on the latest data available at that time.

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

8.2.6 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 intention was for the I-SEM to 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.

8.2.7 This meant 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 created two potential issues:

- Consistency of Interconnector De-Rated Capacity
- Consistency of signals to external CMUs

Consistency of Interconnector De-Rated Capacity

8.2.8 The enduring hybrid solution was not fully defined at the time of the consultation, however CRM Decision 2 (SEM-15-104) did 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.

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

8.2.9 The consultation noted that If capacity which was contracted in GB were prevented from participating in the I-SEM CRM for the enduring solution then this might significantly limit external participation. Capacity would still be delivered to the I-SEM at times of stress based on the functioning of the energy markets regardless of whether capacity was awarded Reliability Options in the CRM.

8.2.10 If it exists, 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.

Consistency of signals to external CMUs

8.2.11 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[25]. This would allow external CMUs full access to the de-rated interconnector capacity for all auctions over the transition between cross-border trading solutions providing consistent signals to such capacity.

8.2.12 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.

8.2.13 It was clear that any additional auction approach would 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).

8.3 SUMMARY OF RESPONSES

Q. 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?

8.3.1 A number of respondents supported the proposed EMDF value of 60%.

8.3.2 One respondent noted the proposal to use a single rate, without analysis of the impact of the use of other values within the modelled range on Ireland's security of supply and LOLE and wished to see this addressed.

8.3.3 This respondent stated that surprised, given the historical higher outage rates (forced and scheduled) for the interconnectors for CY2022/23 vs CY2018/19 that the EMDF values are the same.

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

8.3.4 Another respondent sought further insight on the rationale for choosing the interconnector de-rating value from such a wide range of potential values, with a view to understanding the potential future regulatory direction in this area. They asked if the rationale is that the RAs do not want to deviate much from previous year's de-rating factor and if this were a precedent that the RAs will follow in future.

8.3.5 One respondent stated that the de-rating factors of interconnectors, similar to other technologies, should be continuously reviewed especially in light of changes to methodologies applied in other relevant capacity markets.

8.3.6 One respondent suggested that the use of forward looking modelling outcomes under implicit capacity allocation provides a more robust assessment of interconnector flow than historical analysis, and recommended that the RA's review the existing methodology and consider separate assignment of de-rating factors for the two existing interconnectors as presented in the most recent GB capacity auctions.

8.3.7 One respondent stated that changes to the EMDF should be incremental rather than substantial in order to send a consistent signal. Consideration should be given to increasing the EMDF in line with observed contribution to security of supply from the interconnected market.

8.3.8 One respondent stated that they consider the interconnectors should be de-rated even further, customers would be better served by relying on indigenous capacity that, while subject to normal outage risk is not capable of being withdrawn by a 3rd party at their discretion.

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

8.3.9 No respondent to this question expected to be applying to Qualify a new interconnector between the I-SEM and an external market for this T-4 auction.

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

8.3.10 One respondent stated that there needs to be a workshop and further consultation around what is an extremely important area. Consultation paper sets out many high level fundamental issues which will have a direct and, as yet unquantified large impact on existing and new generators in Ireland as a result of how Interconnector capacity is treated under the interim interconnector approach or the enduring hybrid solution.

8.3.11 One respondent stated with regard to this transition, in the re-auctioning of interconnector capacity, any interconnector capacity volumes not taken up at the re-auction stage should remain with the interconnector owner. This would help reduce the risk of uncovered RO difference payments which would be to the detriment of consumers in terms of exposure to high energy prices and possible socialisation fund costs.

8.3.12 This respondent suggested to reflect the risk that the interconnectors would take in keeping any un-sold ROs, where the re-auction price is less than the original T-4 auction price, the differential should be retained by the interconnector owners.

8.3.13 One respondent considered regulatory certainty and consistency of signals to market participants as key to the success of the CRM auctions. This respondent thinks the same interconnector de-rating methodology should be applied to all the capacity auctions (T-4 and T-1) for the same Capacity Year (2022/23), it was concerned that there is a possibility that new interconnectors may participate in the T-4 auctions CY2022/23 and CY2023/24 and clear a long term contract under the interconnector-led approach. This respondent asked whether the SEM Committee had considered the potential impact of such a scenario.

8.3.14 One respondent stated that high level solution set out in consultation provides insufficient and highly variable investment signals to interconnector developers. Barriers to participation and the risk of very marginal welfare gain from cross border participation in general need to be balanced against the downside risk of design change leading to insufficient signals for interconnector development. This respondent recommends that cross border participation only commences at a future T-4 (e.g. in 2020 for Capacity Year 2024/25) once the planned EU approach is agreed and the legal and regulatory framework for Brexit is finalised, and notes that prior to the definition of the full planned EU approach it would seem sensible to retain the current interconnector de-rating methodology.

8.3.15 One respondent stated that assigning capacity to the technical availability of the interconnector is a reasonable reflection of reality and that there are strong reasons for assigning capacity to the interconnector, rather than to any putative future users of the interconnector. They suggested that if there is capacity in Great Britain that wishes to participate in the I-SEM CRM, it must be required to show how it will access the interconnector whenever the TSO requires it for the I-SEM. If the capacity provider in Great Britain cannot provide the necessary assurances, the I-SEM will be relying on the security of supply provided by the interconnector, but allocating its value arbitrarily to someone in Great Britain who does not actually serve the interests of the I-SEM.

8.3.16 Another respondent stated that they favoured full interconnector participation in T-4 auctions to avoid distortions of the market if practical and efficient arrangements for explicit participation by cross-border units cannot be adequately developed. They stated that it seemed a confusing and bureaucratic exercise to award capacity to interconnectors at T-4 then retrieve those contracts from interconnectors in order to then (re-)distribute the same quantity though a T-1 auction. They suggested that if the interconnectors do not hold any form of reliability obligation (through not participating, transferring their obligations to cross-border units, or some other arrangement) there would be a consequent effect on their incentive to be available.

8.3.17 One respondent described proposals in consultation as speculative and stated there is little merit in considering them until the precise detail of the detailed design of the hybrid solution is known. They suggested keeping it simple over the transition and avoiding the creation of multiple prices and carving up already cleared capacity as such mechanisms will only add confusion and complexity in what is an already complex area. They stated that consideration must also be given to any impact that re-auctioning would have on the secondary market including any impact on liquidity in what will likely be an illiquid market in the early stages.

8.3.18 Another respondent stated they appreciate that this will be a complex undertaking, requiring significant cooperation cross-border. They stated the market codes currently do not make provision for a hybrid solution insofar as cooperation and participation of foreign capacity. They stated that generator licences would be the likely route, though these are separately awarded via country-specific authorities. There would need to be an understanding regarding the boundaries of licensing, minimum standards and market participation requirements that cross-border capacity would have to abide by, and how the market would treat them in terms of capacity market design. They also stated the importance of operating reserve levels for the capacity auction will be affected by the volumes of interconnector participation.

8.4 SEM COMMITTEE RESPONSE

Proposal of EMDF value of 60%

8.4.1 In proposing an EMDF value of 60% for CY2022/23 (the same as used in CY2018/19 and CY2019/20) the RAs saw clear benefits in avoiding volatility in the level of EMDF from year-to-year. This was due to a number of reasons, these included:

- uncertainties affecting a range of the inputs and assumptions to the determination which is greater in a T-4 Auction than for a T-1;
- the volatility of the key National Grid's Future Energy Scenarios (FES) assumptions from forecasting year to forecasting year and their impact on the determination of EMDF; and
- the potential for creating exit signals in one auction which evaporate in the following auction as new information or assumptions about the SEM or GB becomes available.

8.4.2 In proposing an EMDF value of 60% the RAs considered a range of possible values. The analysis as set out in the consultation paper (SEM-18-028) outlined the sensitivity of the EMDF value to changes in different assumptions, with:

- variation in assumptions between the four Future Energy Scenarios and using both a 7% and 10% assumption for average forced outage rate in GB produced values of EMDF that ranged from 32% to 95%; and
- inclusion of additional capacity requirement in respect of operating reserve, or a tighter security standard (reducing the incidence of scarcity in the SEM and increases

the coincidence of scarcity between the SEM and GB) produced values of EMDF that ranged from 18% to 91%.

8.4.3 The SEM Committee favour the above approach of choosing an EMDF value which minimises volatility year to year, however, this value will be reviewed on an annual basis for each relevant capacity year based on the latest data available.

8.4.4 Since the consultation paper was published, NGC has delivered a new set of Future Energy Scenarios (FES 2018) for GB. These scenarios are markedly different from those produced in 2017 and, in general, show increased GB capacity for CY2022/23. The RAs have repeated their analysis using FES 2018.

8.4.5 In addition to the impact of FES 2018, this Decision Paper also proposes the inclusion of a level of operating reserve of between 100MW and 500MW in the demand curve used for the T-4 auction (as set out in paragraph 4.5.2). This decision will have an impact on the expected level of scarcity in the SEM and how often this is coincident with scarcity in GB: with higher levels of reserve increasing the coincidence between scarcity in the two markets. The RAs have evaluated EMDF with 100MW, 300MW and 500MW of reserve included within the demand curve.

8.4.6 The updated EMDF analysis gives a range of 37% to 99% which is broadly consistent with the analysis performed for the consultation paper. In consequence, the SEM Committee have decided to retain the EMDF value of 60% as proposed in that paper.

8.4.7 The SEM Committee note that the outage rate of the interconnectors does not form part of the EMDF analysis, this only considers the availability of capacity in GB to meet potential incidents of scarcity in the SEM. As for other capacity in the SEM, interconnector outage rates are accounted for in the marginal de-rating factors determined by the SOs for the Interconnector Technology Class. However, as indicated in the consultation paper, the Interconnector outage rates which feed into the determination of the Technology Class de-rating factors have been updated to use historic data to the end of 2017.

New Interconnectors

8.4.8 The SEM Committee note that no respondents were expecting to Qualify a new interconnector for the CY2022/23 T-4 Auction. In consequence, EMDF has only been determined for the GB market.

Issues around transitioning from the interim to the hybrid solution for cross-border trading of capacity

8.4.9 As previously set out by the RAs the first T-4 auction will not have direct participation by cross-border capacity, it will operate on the interim interconnector-led approach. The State aid decision requires the I-SEM to move to the enduring hybrid solution for cross-border trading from the auctions taking place in 2020, this means that the T-4 auctions for 2022/23 and 2023/24 would use the interim solution, but the T-1 auctions for 2021/2, 2022/3 and 2023/4 would use the enduring hybrid solution. However, the decision recognises that this process requires the participation of parties external to the SEM which may impact the timing of the transitions.

8.4.10 The RAs set out a possible two-step approach whereby whilst cross-border capacity does not participate directly in the CY2022/23 T-4 auction, but there is a subsequent secondary auction for CY2022/23 capacity in which cross-border capacity participates. The SEM Committee acknowledge concerns from some respondents that this approach adds further complexity to the cross-border arrangements design, and is difficult to determine until the precise detail of the detailed design of the hybrid solution is known.

8.4.11 However, such an approach could alleviate certain potential issues created by having an interim and subsequent enduring cross border design arrangements. The consultation paper (SEM-18-028) described two potential issues, consistency of Interconnector de-rated capacity and consistency of signals to external CMUs.

8.4.12 A number of respondents also noted the issues which could arise if the enduring solution were implemented before the shape of the European cross-border trading arrangements was clear. The SEM Committee recognise that the new Energy regulation (COM2016/1370) is still under negotiation and is likely to impact on the design of the enduring solution.

8.4.13 A number of responses strayed into discussing their preferences for the actual detailed design of the hybrid solution. This parameters paper does not deal with the actual detailed design of the hybrid solution, this will be developed by the RAs and consulted upon separately to this parameters paper in due course.

8.4.14 The SEM Committee will continue to keep all possible options under review, but will abstain from making any decisions on bridging measures (such as on implementing any two-step approach) until further detail is available on the enduring design of the hybrid solution.

8.5 SEM COMMITTEE DECISIONS

8.5.1 The SEM Committee have decided to retain an EMDF value of 60% for GB, as proposed in the consultation paper.

8.5.2 The SEM Committee have decided that the interconnector outage rates will be as set out in the consultation paper.

Table 1: Summary of EMDF and interconnector outage rates and 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%†

† Overall de-rating has been estimated, the actual value will appear in the Initial Auction Information Pack

8.5.3 For this decision, values for EMDF and outage rates have been determined only for the GB market. Determinations for other markets will be considered as and when applications to qualify an interconnector linking the SEM to such other markets are received, including to facilitate new entry for the CY2022/23 auction if required.

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[26]. 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.

9.2 CONSULTATION SUMMARY

9.2.1 The RAs recently carried out a review of the BNE cost estimates and the report contains updated estimates of the gross investment costs of OCGTs and CCGTs in Ireland and Northern Ireland[27]. 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).

9.2.2 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.

9.2.3 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 2 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.

9.2.4 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;

[26] which has been fixed as a maximum of 10 years in CRM Decision 3 (SEM-16-039)

[27] 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

- This analysis does not represent strong evidence in favour of a change to the NCIRT of €300/de-rated KW for the time being.

Table 2: 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**

9.3 SUMMARY OF RESPONSES

Q. 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)?

9.3.1 Respondents were broadly in favour with proposal however some suggested some slight changes, stating:

- They understand that the Best New Entrant consultation could arrive at a higher BNE Net CONE mainly as a result of change of reference technology and believe that this should be reflected in an increased NCIRT should this technology be chosen;
- There should there be no change in technology we understand that the rate should increase to €305/de-rated kW;
- They support the current policy provided it is updated in line with the BNE decision as relevant;
- A high level of NCIRT should be maintained. This is to ensure only genuine new best-in-class technology is deployed, rather than basic refurbishment of older plants for the purposes of extending operation for short periods. The NCIRT should therefore be revised upward in line with inflation and the findings of the BNE consultations; and

- It may be useful to consider the real figure, deflated to reflect the lost value of money, over time.

9.3.2 One respondent described a need for a lower NCIRT in relation to refurbishment (for a shorter contract, GB style), describing as an inefficient disincentive against refurbishing existing plant. They made an argument for this lower NCIRT (for plant upgrades of €50 per kW of de-rated capacity) for refurbishing existing plant.

9.4 SEM COMMITTEE RESPONSE

9.4.1 The gross BNE cost is the investment that a low cost new investor on a greenfield site would be expected to make. However, it is expected that most genuine new build capacity would have a gross investment cost at least equal to the gross BNE cost.

9.4.2 The Best New Entrant consultation report (SEM-18-025a) looked at and summarised the investment costs for OCGTs running on distillate, OCGTs running on gas and CCGTs in both Ireland and Northern Ireland. In the BNE decision document SEM-18-156 the SEM committee provided some updates to the estimated gross investment costs. These revised estimates, which are not materially different to those presented in SEM-18-025a are set out in 3 below

9.4.3 This analysis still does not provide strong evidence to support a change to the NCIRT of €300/de-rated KW for the time being.

Table 3: Updated gross investment costs

	Ireland			Northern Ireland		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
EPC costs	93.0	93.4	284.1	91.6	92.8	285.1
Site procurement cost	0.7	0.7	3.0	0.9	0.9	3.7
Electrical connection costs	5.7	5.7	5.7	5.7	5.7	7.9
Water connection costs	0.5	0.5	0.6	0.5	0.5	0.6
Gas connection costs	-	5.6	6.1	-	5.6	6.1
Owners contingency	4.7	4.7	14.2	4.6	4.6	14.3
Financing costs	1.9	1.9	5.7	1.8	1.9	5.7
Capital during construction	5.3	5.5	25.2	5.4	5.7	26.3
Insurance	0.8	0.8	2.6	0.8	0.8	2.6
Initial fill of fuel oil tanks	1.8	1.6	4.3	2.4	3.4	5.7
Project development	5.6	5.6	17.0	5.5	5.6	17.1
Commissioning utilities costs	2.3	2.3	7.1	2.3	2.3	7.1
Operating spares	1.4	1.4	4.3	1.4	1.4	4.3
Accession fees	-	-	-	-	-	-
Participation fees	-	-	-	-	-	-
Total gross investment cost €m, 2017 prices	**123.8**	**129.8**	**380.0**	**122.8**	**131.4**	**386.4**
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	716	719	974	710	728	990
40% of gross investment cost €/derated kW, 2017 prices	286.42	287.60	389.61	284.11	291.15	396.17
40% of gross investment cost €/derated kW, 2022/23 prices	**320.96**	**322.29**	**436.60**	**318.37**	**326.26**	**443.95**

9.4.4 The RAs set out reasons for not having a refurbishing category eligible for multi-year Reliability Options in CRM Decision 2 (SEM-16-022), and the SEM Committee does not intend to revisit this arrangement at this point in time. The SEM Committee's aim in setting the NCIRT is to decide what constitutes as a level of financial investment reasonable for an investor to bear without a multi-year contract, and what level of risk is appropriately mitigated by a contract of up to 10 years. The SEM Committee believes that it is reasonable for an investor to bear the risk on investments of less than €300/kW.

9.4.5 The SEM Committee has implemented some measures to incentivise efficient refurbishment:

- As set out in CRM Parameters decision (SEM-17-022) for CY 2018/18, a refurbishing plant is allowed a proportion of their investment costs (Unavoidable Future Investment) into their Unit Specific Price Cap (USPC) applications; and
- The proposal to set the New Capacity Investment Rate Threshold at 40% of the gross BNE cost should ensure that any significant capacity, even on a brownfield site, should be able to bid for a Reliability Option of up to 10 years.

9.5 SEM COMMITTEE DECISIONS

9.5.1 The SEM Committee has decided to set the New Capacity Investment Rate Threshold (NCIRT) at €300/de-rated kW, this is consistent with the NCIRT level for the first two transitional T-1 auctions (for CY2018/19 and CY 2019/20). This is in the light of the analysis on BNE gross investment costs as set out in the consultation.

9.5.2 The SEM Committee does not intend to revisit the decision regarding including a refurbishment category eligible for multi-year Reliability Options at this point in time.

10. SUMMARY OF PARAMETERS

10.1 INTRODUCTION AND CONSULTATION SUMMARY

10.1.1 Section 10 of SEM-18-028:

- Provides a summary of the potential changes to the key parameters for CY2022/23; and
- Gave stakeholders an opportunity to provide comments on any of the parameters, which are not already covered in their responses to other consultation questions.

10.1.2 In this section we discuss additional responses received, and summarise the final position on key parameters.

10.2 SUMMARY OF RESPONSES

Q. 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?

10.2.1 One respondent stated that recognise that market power is a concern, as an independent generator of power are concerned that the Regulators have not proposed a price floor. They stated that without a floor, vertically integrated entities with inefficient units could ignore economic signals to exit the market by continuing to operate some of their portfolio at a loss. Ultimately independent generators could be forced to exit the market. In the long term, the environment and consumers of power would pay more for a less efficient fuel mix.

10.2.2 One respondent stated that basis for allocating demand to constrained regions is not yet clear. There was no equivalent statement to "least-worst-regrets methodology" of the basis for allocating demand to constrained regions. They stated it is not clear which data was used from Ten-Year Transmission Forecast Statement (TYTFS) for this exercise.

10.2.3 This respondent stated the higher levels of demand forecast for the system as a whole will only be reached if there is significant demand growth in the Dublin area, hence the proportion of the demand allocated to Dublin should reflect that expectation, or else the least-worst-regrets principle is not being maintained. They stated that the consequences of underestimating demand in a constrained area are, if anything, likely to be more severe than for the system as a whole.

10.3 SEM COMMITTEE RESPONSE

10.3.1 The SEM Committee considered and rejected a price floor in CRM Decision 3 (SEM-16-030). The SEM Committee believes that the reasons set out in that document are still valid. In particular, in SEM-16-030, the SEM Committee stated that a, "bid floor would have a similar effect to price floors and therefore would likely raise issues with the CRMs consistency with the EC State Aid Guidelines".

10.3.2 The SEM Committee notes that there may be opportunities to improve the transparency over which demand forecasts have been used to generate the estimates of minimum MWs. Whilst separate demand forecasts are published for Ireland and Northern Ireland, there is less transparency over the demand forecasts for the defined Greater Dublin area. The SEM Committee looks forward to working with the TSOs to improve the transparency of demand forecasts used in the calculation of minimum MWs where possible. The objective of improved transparency needs to be balanced against commercial confidentiality, where publishing more granular demand forecasts would reveal information about assumptions for particular end consumers, such as large data centres.

10.4 SUMMARY OF PARAMETER VALUES

10.4.1 We have summarised the position on the key parameters for CY2022/23 in **Error! Reference source not found.** below:

- Some parameters remain unchanged from CY2019/20;
- Other parameters have been updated only for changes in assumptions (e.g. inputs relevant to CY2022/23 rather than CY2018/19);
- Other parameters 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 published in SEM-18-030;
- Other parameters reflect specific T-4 decisions made in this document.

Table 4: summary of parameter decisions

Parameter	Actual T-1 2018/19	Decision T-1 2019/20	Description of Potential Changes for T-4	
			Policy	Inputs and values
Auction Price Cap	€123,190/MW per year. £ value based on CY2018/19 auction exchange rate	€123,190/MW per year. £ value based on CY2019/20 auction exchange rate	No change: Keep at 1.5 x Net CONE	€138,450/MW per year, reflecting updated BNE Net CONE estimate. £ value based on CY2022/23 auction exchange rate
Existing Capacity Price Cap	€41,060/MW per year. £ value based on CY2018/19 auction exchange rate	€41,060/MW per year. £ value based on CY2019/20 auction exchange rate	No change: Keep at 0.5 x Net CONE	Update for new Net CONE estimate resulting from BNE consultation
Capacity Requirement	7030 MW based on demand forecast for CY2021/22	7030 MW based on demand forecast for CY2021/22 (with potential adjustment for inclusion of a measure of reserves, with measure of reserves to be consulted on)	Retain 8 hour LOLE standard. Policy is to include a proportion a measure of reserve between 100 and 500MW, with final value subject to further consultation. Given timings, reserves not included in value published in CY2022/23 IAIP, but will be reflected in CY2022/23 T-4 auction via adjustment to final Demand curve	Estimate of 7,524 MW included in IAIP excludes any reserves, based on 2018 GCS demand forecasts for CY2022/23. Reserves will be included via a subsequent adjustment to the Final Demand Curve.
Volume withheld from T-4 to T-1	Not relevant	Not relevant	Withheld percentage may include a proportion of the CR which reflects: the level of participation of DSUs seen during T-4 auction Qualification process; and to reflect demand uncertainty. SEM Committee may decide to applying different withheld percentages in the different LCCAs, depending on local variations in both the level of demand uncertainty and the level of DSU participation in those areas	Values to be determined by SEMC and publsihed in FAIP
Indicative Demand Curve Shape	As per T-1 CY 2018/19 FAIP	Same shape as T-1 CY 2018/19 auction	Option B as set out in Section 6	Updated based on 2018 GCS forecast for CY2022/23, and published in CY2022/23 T-4 IAIP. Final demand curve (publsihed in FAIP) will also be adjusted for: non-participating capacity; and withheld percentage for DSU participation and demand forecast uncertainty
Locational Capacity Constraint Areas (including nodes)*	Level 1: Ireland and NI. Level 2: Dublin. Full definition in CY2018/19 IAIP & FAIP	Level 1: Ireland and NI. Level 2: Dublin. Full definition in CY2019/20 IAIP & FAIP	Inclusion in auction design. Minimum MW may also include allocation of operating reserves to LCCAs (subject to separate consultation)	Area definition and minimum MW based on updated TSO analysis for CY2022/23. Level 1: Ireland and NI. Level 2: Dublin. Area definitions published in CY2022/23 T-4 IAIP. Minimum MWs to be published in CY2022/23 T-4 FAIP.

Parameter	Actual T-1 2018/19	Decision T-1 2019/20	Description of Potential Changes for T-4	
			Policy	Inputs and values
De-rating Curves for DSUs (with Maximum Down Time >6 hrs)	System wide de-rating used	As per CY2018/19 FAIP	As set out in SEM-18-030	Final values updated by TSOs, approved by SEMC and included in CY2022/23 T-4 IAIP.
De-rating Curves for DSUs (with Maximum Down Time ≤ 6 hrs)	N/A	Apply De-Rating Curves for "Other Storage" (SEM-18-030)	As set out in SEM-18-030	Final values updated by TSOs, approved by SEMC and included in CY2022/23 T-4 IAIP.
De-rating curves for Interconnectors	As per IAIP/FAIP	As per CY2018/19 FAIP	See Section 8	Values calculated by RAs shown in Section 8, and published in the CY 2022/23 T-4 IAIP
De-rating Curves by Tech Class (excluding Interconnectors)	As per IAIP/FAIP	As per CY2018/19 FAIP	No changes	TSOs' update estimates approved by SEMC and included in CY2022/23 T-4 IAIP with potential minor changes to reflect input assumption changes
Tolerance Bands	All 0% except DSU 100% DECTOL	All 0% except DSU 100% DECTOL	As set out in SEM-18-030 (run-hour limited generation)	Final values as approved by SEMC and included in CY2022/23 T-4 IAIP
New Capacity Investment Rate Threshold	€300,000 MW; 40% BNE Invt Cost	€300,000 MW	No change	€300,000 MW
Performance Securities	As per FAIP - staggered rates	As per CY2018/19 FAIP	Same as CY2018/19 FAIP	Same as CY2018/19 FAIP
Termination Charges	As per FAIP - staggered rates aligned with performance securities	Same as CY2018/19 FAIP	Same as CY2018/19 FAIP	Same as CY2018/19 FAIP
Administered Scarcity Price	Reserve 500MW; ASP €500 - €3000/MWh	Reserve 500MW; ASP €500 - €3000/MWh	Reserve 500MW; ASP €500 - 25% of VoLL	VoLL equal to €11,128.26/MWh in Calendar 2018. Value for CY2022/23 will depend on outturn inflation, and could be subject to addditional review
Strike Price parameter: DSU Floor Price	€500 MW	€500 MW	No change	€500 MW
Strike Price parameters: Others	As per FAIP	As per CY2018/19 FAIP	No change	TSOs provide updated values for SEMC approval for CY2022/23 T-4 IAIP
Annual Capacity Payment Exchange Rate	As per FAIP	Updated exchange rate	No change	Indicative rate (0.9478GBP=1EUR) included in CY2022/23 T-4 IAIP and final rate to be FAIP, based on market quotes for CY2022/23 forward period
Awarded Capacity	Zero	Zero	No change	Zero
Annual Stop-Loss Limit Factor	1.5	1.5	No change	1.5
Billing Period Stop-Loss Limit Factor	0.5	0.5	No change	0.5

*Locational Capacity Constraint Minimum Requirement is provided in FAIP only.

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[28], 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

[28] 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

Initally, price-quantity pairs will be scheduled without consideration of Locational Capacity Constraints or inflexibility, as set out in section F.8.3. In accordance with paragraph F.8.4.4(c), only price-quantity pairs with a price less than the Offer Price Clearance Ratio[29] of the Auction Clearing Price shall be cleared at this stage.

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 6illustrates a set of offers that contribute to satisfying a Locational Capacity Constraint. Some of these offers may already have been 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.

[29] The Offer Price Clearance Ratio is currently set to zero, and so no price-quantity pairs are cleared during Initial Clearing.

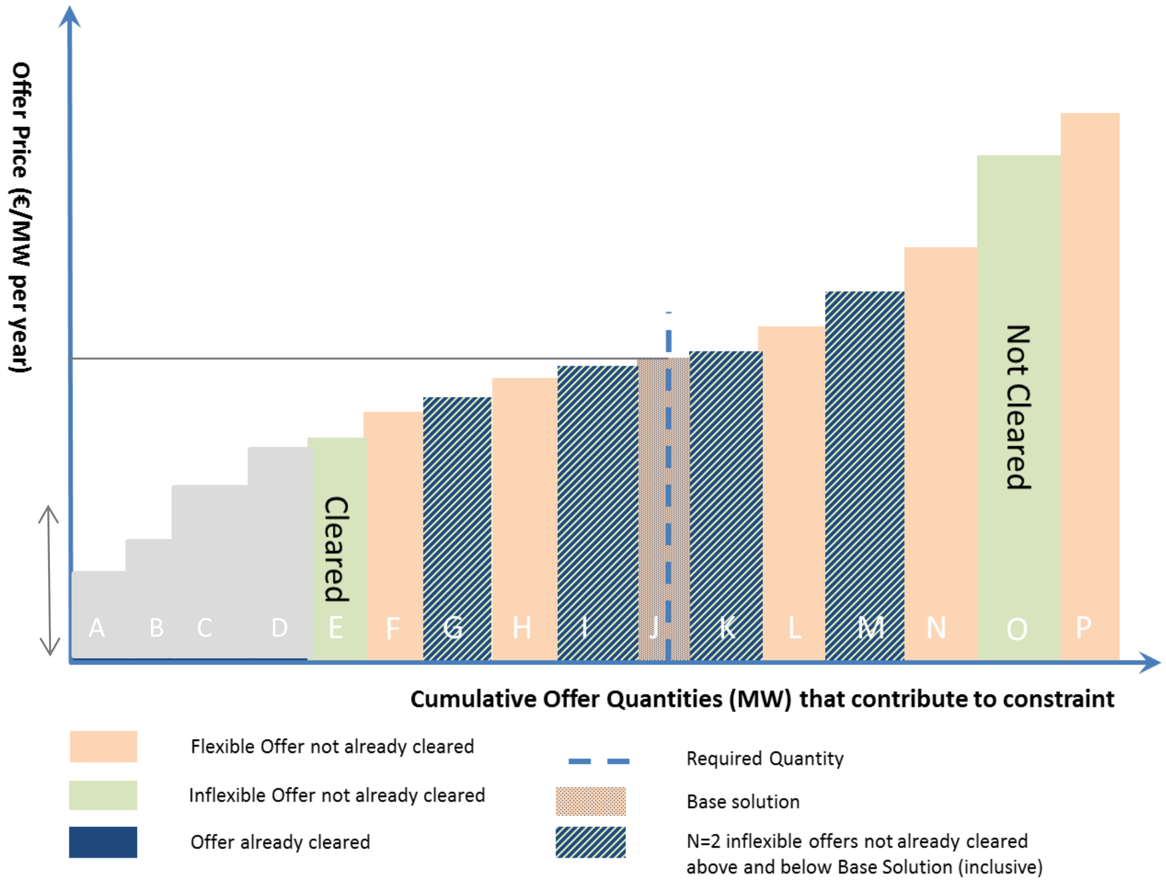


Figure 6: Identifying feasible solutions based on subset of inflexible offers not cleared for N=2

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 6, 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[30]. Where a tie exists, the approach in step 2 applies. In Figure 6, N=2 and the subset of offers to be considered is G, I, K and M.

[30] 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 6, 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 6, 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 6, 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 6, 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 of the Locational Capacity Constraint process 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.