Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism (CRM)

T-4 Capacity Auction for 2022/23

Best New Entrant Net Cost of New Entrant

(BNE Net CONE)

Decision Paper

SEM-18-156

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 European Commission (EC) gave State aid approval for the CRM on 24 November 2017.

The first transitional T-1 Capacity Auction took place in December 2017 for Capacity Year (CY) 2018/19. The second transitional T-1 Capacity Auction is due to take place on 13 December 2018. This decision specifically relates to the first T-4 Capacity Auction which relates to Capacity Year 2022/23 and is scheduled for 28 March 2019[1].

As part of the I-SEM CRM design the SEM Committee committed to reviewing the key assumptions in setting the Best New Entrant Net CONE before the first T-4 auction for Capacity Year 2022/23[2]. The rationale being that more significant 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.

Previous SEM BNE assessments have focused on peaking plants in order to serve the final megawatt (MW) of demand, however given this BNE assessment will apply to the new capacity market arrangements with a focus on procuring a set amount of capacity via a competitive auction process, it is the SEM Committee's view that this BNE assessment should more generally reflect the technology and cost decisions a rational investor would take within the new all-island market.

Therefore the recent consultation on the Best New Entrant Net Cost of New Entry (BNE Net CONE) (SEM-18-025)[3] reflected this change in purpose for the BNE assessment which included an estimate of the Net CONE for a peaking plant that meets a set of criteria similar to those previously used to determine the BNE peaking plant under the SEM Capacity Payment Mechanism and also introduced an estimated Net CONE for a Combined Cycle Gas Turbine (CCGT) given the evidence of recent investment in the SEM.

The SEM Committee is of the view that the lowest Net CONE value should represent the Best New Entrant as it provides an appropriate expectation of a rational investor within a competitive capacity auction process whilst also being mindful of the need to protect consumers. Based upon the analysis carried out for the consultation the SEM Committee proposed that a CCGT located in Northern Ireland should represent the Best New Entrant based upon the lowest Net CONE value presented in the consultation paper.

[1] T-4 CY2022/23 Capacity Auction Timetable: http://www.sem-o.com/ISEM/General/CAT2223T-4%20-%202022%202023%20T-4%20Capacity%20Auction%20Timetable.pdf
[2] CRM Auction Parameters Decision SEM-17-022
[3] https://www.semcommittee.com/news-centre/i-sem-crm-t-4-cy202223-best-new-entrant-consultation

11 responses were received to the CRM T-4 CY 2022/23 BNE Net CONE consultation which were all non-confidential. The responses to the consultation (SEM-18-025) have been published on the SEM Committee website.

The majority of respondents were concerned with the introduction and recommendation made in the consultation paper that the Best New Entrant be a CCGT. The range of concerns include: feasibility of timing of construction, assumed energy market revenue, assumed DS3 revenue, location of the unit, the Weighted Average Cost of Capital (WACC) and a lack of emphasis for flexible plant.

As mentioned in the consultation paper the final BNE Net CONE decision will reflect updated assumptions to align with other T-4 parameter decisions and will also reflect the latest available information.

Having updated the assessment the SEM Committee has decided that the Best New Entrant applicable to the first T-4 Capacity auction (CY2022/23) is an OCGT, firing on distillate fuel, located in Northern Ireland. The estimated **BNE Net CONE value is €92.3/de-rated kW/per year**. This move from a proposed CCGT to an OCGT as the Best New Entrant is a result of moving from a sea-water cooled to an air-cooled CCGT and the recognition of the cost of equity during construction.

The WACC applied is a **real pre-tax WACC of 5.4%,** and represents a move from the current CPM WACC of 5.17%. A key driver for this change is the observed changes to the underlying market data whilst recognising the presence of a ten year Reliability Option which should help de-risk new projects.

This BNE Net CONE value and corresponding BNE Gross Investment Cost has been used to inform the following parameters for the first T-4 CY2022/23 capacity auction which are detailed further within the T-4 CY2022/23 Parameters Decision[4]:

- **Auction Price Cap (APC):** The maximum price qualified bidders may bid their qualified volume at, and is therefore the maximum price that the auction can clear at. For the T-4 CY2022/23 capacity auction this will be set at a multiple of 1.5 of Net CONE being €138.45/de-rated kW/per year.
- **Existing Capacity Price Cap (ECPC):** A uniform price cap to apply to all existing capacity providers (except DSUs), with the exception of those who apply and receive a Unit Specific Price Cap. For the T-4 CY2022/23 capacity auction this will be set at a multiple of 0.5 of Net CONE being €46.15/de-rated kW/per year.
- **New Capacity Investment Rate Threshold (NCIRT):** The amount that a new investor must invest per de-rated MW of capacity to qualify for a multi-year Reliability Option. This parameter is approximately based on 40% of the gross BNE investment cost. For the T-4 CY2022/23 capacity auction this will be set at €300,000/de-rated MW.

[4] SEM-18-155 T-4 Parameter Decision Paper

Contents

1. OVERVIEW

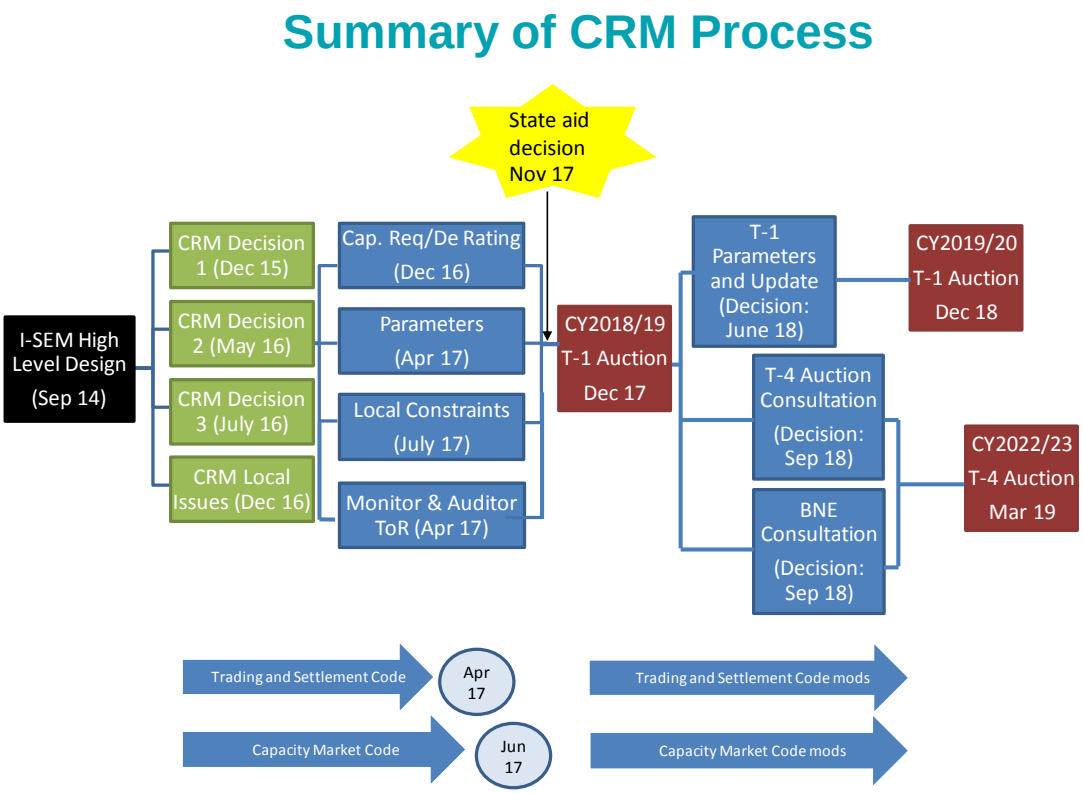
1.1 BACKGROUND

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 Throughout the design and implementation process of the I-SEM (including CRM) the intention was to avoid any unintended consequences. In order to manage the risk of unintended consequences occurring an I-SEM Rules Working Group was established. The aim of this group was to ensure the processes were robust and, through their involvement, utilised industry input and feedback. Industry input was provided through regular opportunities to provide feedback on the drafting of processes.

1.1.3 Decisions made during the aforementioned consultations were translated into auction market rules to form the Capacity Market Code (CMC) (SEM-17-033) 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



1.1.4 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.

1.1.5 The EC approved the CRM on 24 November 2017[5], based upon some further commitments given by the Departments to the EC during the State aid approval process. The State Aid commitments had/have limited impact on the Capacity Year (CY) 2018/19 and CY2019/20 T-1 auctions, but have a material impact on the first T-4 auction (for CY2022/23) and the remaining two transitional auctions for CY2020/21 and CY2021/22.

1.1.6 The first Capacity Auction took place in December 2017 to cover the period from I-SEM go-live to 30 September 2019, and is referred to as CY 2018/19. The second transitional T-1 capacity auction is due to take place on 13 December 2018 and relates to capacity year 2019/20[6]. Furthermore, the first T-4 Capacity Auction for capacity year 2022/23 is now planned to take place on 28 March 2019[7], for which this decision relates.

1.2 PURPOSE OF THIS DECISION PAPER

1.2.1 Following consultation on the first Capacity Auction parameters the SEM Committee decided to review the key assumptions (including the Weighted Average Cost of Capital (WACC)) in setting the Net Cost of New Entry (Net CONE) before the first T-4 auction for Capacity Year 2022/23[8]. The rationale being that more significant 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.

1.2.2 The SEM Committee previously carried out a detailed bottom-up review of the BNE Net CONE specifically for a peaking plant to apply to the 2016 Annual Capacity Payment Sum under the Capacity Payment Mechanism. This BNE Net CONE has since been uplifted to apply to subsequent years and was used as the basis of the Net CONE calculation for the CRM T-1 transitional auctions to date.

1.2.3 It is the SEM Committee's view that the primary focus for this BNE assessment going forward is that it should more generally reflect the technology and cost decisions a rational investor would take within the new all-island market. This change in focus for a BNE assessment within the

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

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

[7] T-4 CY2022/23 Capacity Auction Timetable: http://www.sem-o.com/ISEM/General/CAT2223T-4%20-%202022%202023%20T-4%20Capacity%20Auction%20Timetable.pdf

[8] CRM Auction Parameters Decision SEM-17-022

new Capacity Market has resulted in the introduction of a Net CONE assessment for a Combined Cycle Gas Turbine (CCGT) given the evidence of recent investment in the SEM.

1.2.4 The SEM Committee engaged Poyry Management Consulting to assist the RAs in a bottom up assessment of the fixed costs and Net CONE of a BNE peaking plant that meets a set of criteria similar to those previously used to determine the BNE peaking plant under the SEM Capacity Payments Mechanism and a BNE Combined Cycle Gas Turbine (CCGT).

1.2.5 Where possible, the methodology applied is consistent with that used for previous BNE calculations, however adjustments are necessary to make the BNE applicable to the capacity market design. These adjustments are detailed further within this decision paper and the accompanying Poyry Report.

1.2.6 This BNE Net CONE assessment has been updated since the consultation to reflect and align with other T-4 parameters and has also been updated for the latest available information.

1.2.7 This decision paper summarises the BNE Net CONE assessment and decisions made by the SEM Committee are based upon views from the consultation responses and the updated analysis by Poyry. The detail accompanying this decision is contained with the Poyry report which is attached as Appendix A to this paper.

1.2.8 The SEM Committee is of the view that the lowest Net CONE value should represent the Best New Entrant as it provides an appropriate expectation of a rational investor within a competitive capacity auction process whilst also being mindful of the need to protect consumers.

1.2.9 This BNE Net CONE value and corresponding BNE Gross Investment Cost has been used to inform the following parameters for the first T-4 CY2022/23 capacity auction which are detailed further within the T-4 CY2022/23 Parameters Decision:

1.2.10 The final BNE Gross Investment Cost and BNE Net CONE will first be applied to setting the following parameters for the first T-4 capacity auction being CY2022/23:

- **Auction Price Cap (APC):** The maximum price qualified bidders may bid their qualified volume at, and is therefore the maximum price that the auction can clear at. This is set as a multiple of Net CONE.
- **Existing Capacity Price Cap (ECPC):** A uniform price cap to apply to all existing capacity providers (except DSUs), with the exception of those who apply and receive a Unit Specific Price Cap. This is set as a multiple of Net CONE.
- **New Capacity Investment Rate Threshold (NCIRT):** The amount that a new investor must invest per de-rated MW of capacity to qualify for a multi-year Reliability Option. This parameter is based approximately upon 40% of the gross BNE investment cost.

1.2.11 It is important to note the references to BNE Net CONE has the same meaning as Best New Entrant price (BNE price). In capacity terms, both Net CONE and BNE price are presented as a

monetary figure per unit of de-rated capacity per year. In this decision these values are on a €/de-rated kilowatt/year basis.

1.2.12 Each chapter of this decision paper sets out a summary of the consultation proposal, provides a summary of responses, and sets out the SEM Committee's decision.

1.3 RESPONSES TO CONSULTATION

1.3.1 This paper includes a summary of the key points respondents made to the CRM T-4 Capacity Auction for 2022/23 Best New Entrant Net Cost of New Entrant (BNE Net CONE) consultation paper (SEM-18-025), which closed on 15 June 2018.

1.3.2 A total of 11 responses to the consultation were received which are outlined below and copies can be obtained from the SEM Committee website.

- ART Generation
- BGE
- Bord na Mona
- EAI
- Energia
- Ennercomm International
- ESB
- Grange
- Power NI PPB
- SSE
- Wartsila

1.4 ASSESSMENT CRITERIA

1.4.1 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.

1.4.2 These assessment criteria are set out below:

- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.
- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Competition**: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system.
- **Practicality/Cost**: the cost of implementing and participating in the CRM should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

1.4.3 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. REFERENCE TECHNOLOGIES

2.1 INTRODUCTION

2.1.1 The first step in this BNE Net CONE assessment is to propose suitable technology options, applicable for use in the Capacity Market for auctioning capacity for the Capacity Year 2022/23.

2.1.2 Previous SEM BNE assessments were carried out periodically as part of the Capacity Payments Mechanism, a fixed revenue mechanism which collected a pre-determined amount of money, the Annual Capacity Payment Sum from supplier and paid these funds to available generation capacity in accordance with rules set out in the Trading and Settlement Code. The value of the Annual Capacity Payment Sum was determined as the product of two number:

- A Quantity (the Capacity Requirement) – determined as the amount of capacity required to exactly meet an all-island generation security standard; and
- A Price – determined as the annualised fixed costs of a Best New Entrant peaking plant net of Infra-marginal rent and ancillary services revenue, expressed in €/kW per year.

2.1.3 The previous SEM BNE calculations were designed to determine the costs that a rational investor in a peaking plant, which served the final megawatt (MW) of demand, would incur at the point when the market was in equilibrium. The characteristics of the BNE plant for which costs were derived was that the notional plant could be located in either Ireland or Northern Ireland and use the plant and fuel type which proved most cost efficient. The plant serving the final megawatt of demand was expected to only operate for a very small proportion of the time.

2.1.4 With the introduction of the new I-SEM Capacity Remuneration Mechanism (CRM) a BNE Net CONE assessment is still relevant however its purpose within the CRM is very different. The CRM moves to procuring a pre-defined capacity requirement as part of a competitive process and therefore sends both exit and investment signals.

2.1.5 Within the CRM new capacity can apply for a multi-year Reliability Option of up to 10 years. To qualify for participation in the capacity auction for a multi-year Reliability Option, *inter alia*, a New Capacity Investment Rate Threshold (NCIRT) must be met. This threshold is based approximately upon 40% of the Gross Best New Entrant Investment Cost and expressed in terms of €(or £)/de-rated MW)[9]. Ultimately, to be awarded a multi-year Reliability Option the new capacity must be successful in the competitive auction process. Furthermore, within the new CRM the BNE Net CONE assessment is used as the basis for setting separate values for the Auction Price Cap and the Existing Capacity Price Cap expressed as €(or £)/kW per year. The multiple of BNE Net CONE for each of these price caps are set out in the separate T-4 CY 2022/23 parameters decision paper (SEM-18-155).

[9] This is the gross investment spend, not an annualised value which is the case for Gross CONE and Net CONE

2.1.6 The above outlines the change in purpose of the BNE assessment within the CRM and how the BNE assessment should more generally reflect the technology and cost decisions a rational investor would take within the new all-island market as a whole. In recent years, within the SEM, investors' technology choice has been the CCGT ranging from 343 MW to 464 MW. Other capacity markets such as GB and PJM have also considered the Net CONE of CCGTs. It is for these reasons the Regulatory Authorities requested that Poyry carryout an estimate of the Gross Investment Cost and Net CONE for both:

- A peaking plant that meets a set of criteria similar to those previously used to determine the BNE peaking plant under the SEM CPM; and
- A Combined Cycle Gas Turbine (CCGT) of a size that would not exceed the size of the current largest infeed in the all-island system[10].

2.2 CONSULTATION SUMMARY

2.2.1 For the consultation paper an assessment of the wide range of available technologies was made to ascertain feasible technology options for the BNE reference peaking plant.

2.2.2 In looking at this afresh, Poyry are of the view that interconnectors, Aggregated Generating Units (AGUs) and pumped storage should not be considered further as feasible options for the BNE reference peaking plant. Technology options such as battery storage, compressed air energy storage and flywheel, and open cycle gas fired reciprocating engines, which could potentially be considered as a 'peaking plant', have for various feasibility reasons not been considered appropriate as the BNE reference peaking plant. Chapter 3 of the Poyry report detail the reasons for not considering these technologies further which broadly include a lack of commercial experience, difficulty in determining costs and environmental reasons.

2.2.3 Poyry therefore concluded that the only technology to be considered further as a potential BNE peaking plant is an Open Cycle Gas Turbine (OCGT).

2.2.4 A selection criteria was then applied to initially filter a wide range of gas turbines. The criteria applied for short listing technologies is summarised in Table 1 below.

Table 1: Reference Peaking Plant Selection Criteria

Criteria
Is the gas turbine model commercially proven, with over 8,000 hours of commercial operation at three different sites?
Can the gas turbine model operate on distillate fuel oil as back up fuel in order to comply with secondary fuel obligations in both Ireland and Northern Ireland?
Can the gas turbine model comply with the environmental requirements?
Can the gas turbine model reach full load from a cold start in under 20 minutes?

[10] Currently East West Interconnector at 500 MW

2.2.5 Having applied this criteria and given consideration to the lowest specific capital cost, a shortlist of four gas turbine models was identified. In order to make the final selection a more detailed assessment of their net electrical output and EPC[11] contract price was modelled using Thermoflow GTPRO and its associated cost estimating program PEACE[12].

2.2.6 Based on Poyry's detailed assessment the **BNE reference peaking plant chosen was a Siemens SGT5-2000E** and this was considered appropriate for use as the BNE peaking plant for capacity year 2022/23. The average lifetime output is 190 MW on distillate and 198 MW on dual fuel.

2.2.7 To select the technology for a reference CCGT consideration was given to the technology choices made by investors for the most recent gas fired CCGT in Ireland and Northern Ireland. All of the eight projects identified used F class gas turbine technology and therefore the **BNE reference CCGT plant was the GE 9F.05** gas turbine, with a capacity of 447 MW.

2.2.8 The detailed approach taken to select the above reference plants is set out in Chapter 3 of the attached Poyry report (Appendix A).

2.2.9 The technical assumptions for both selected reference plants were built into the performance and cost models. These reference plants were then assessed based on the costs associated with locating in either Northern Ireland or Ireland, and the reference peaking plant is also assessed by fuel type i.e. distillate or dual fuel.

2.3 SUMMARY OF RESPONSES

2.3.1 As a general comment, some respondents considered the flexibility of plant within I-SEM as being an increasingly important criteria and raised concerns about both the reference technology choices and the relative size of these units. A small number of respondents gave a preference for reciprocating engines due to the flexibility they can provide.

2.3.2 Support was received for the SEM Committee having given consideration to a possible shift in technologies. However a range of concerns were raised in relation to the inclusion of CCGTs, specifically respondents were concerned with the feasibility of the market to build a CCGT for the Capacity Year commencing 1 October 2022, inflexible and risk of stranding of a large asset, location, cost and load factor assumptions and the inframarginal rent estimations for a CCGT.

2.3.3 There was strong support for an OCGT peaking plant remaining as the Best New Entrant. Reasons given for the preference for OCGTs were: retains market stability, avoids regulatory risk associated with switching technology, OCGTs are the technology choice in other capacity markets.

[11] Engineering Procurement Construction

[12] Thermoflow GTPRO is a well-established automated system design software which automates the process of designing a combined cycle or gas turbine plant. PEACE (Plant Engineering and Cost Estimator) is a separately licensed module which can be run in conjunction with GTPRO and provides additional inputs to automate the preliminary engineering and cost estimation of each plant, as designed in GTPRO.

2.3.4 A proposal was suggested that a fairer basis to reflect the actual costs of real investors might be an average of the four candidate OCGTs rather than relying on a snapshot selection of the cheapest OCGT.

2.4 SEM COMMITTEE RESPONSE

2.4.1 For this BNE assessment consideration was given afresh to the wide range of technologies and which technologies are feasible to take forward as a BNE reference plant. Technology options such as battery storage and gas fired reciprocating engines, could in the first instance, potentially be considered as a 'peaking plant'. However, upon further consideration of open cycle reciprocating engines, solely on the basis of a 'static' MW remuneration, the technology was viewed unlikely to be the choice for a rational investor based on capital cost alone. Furthermore, battery storage is becoming increasingly widespread, however due to volatility in recent years in estimating costs and income, battery storage is not considered an appropriate technology choice for this BNE assessment but could be considered as a potential choice for future BNE assessments.

2.4.2 CCGTs have been the preferred technology choice in recent years in the all-island market and therefore this BNE assessment took into consideration the actual market outcome for technology choice. The first T-4 capacity auction is scheduled for 28 March 2019 and relates to a capacity year commencing 1 October 2022. This implies a lead time of 42 months. The BNE assessment assumes a 30 month construction period for an F class CCGT (EPC contract duration) thereby allowing 12 months for a project development phase. This is considered achievable, noting that many project development activities should already have occurred prior to the T-4 auction. In the event a project is delayed the Capacity Market Code has set the Long Stop Date equal to 18 months after the start of the Capacity Delivery Year. This Long Stop Date is the date by which Awarded New Capacity must meet the Minimum Completion i.e. have delivered 50% of its contracted capacity.

2.4.3 Concerns were raised by respondents regarding the location assumptions for the CCGT including an inconsistency between assuming agricultural land/greenfield site and a coastal site providing for direct seawater cooling. There is merit in the concerns raised and that the coastal location restricts the site choice. Within the all-island market many CCGTs have an inland site and use an air cooled condenser. Therefore the CCGT technical assumption has been updated and now assumes an inland site using an air cooled condenser rather than seawater cooling. This has had an impact on the plant performance causing a reduction to the net output and the net efficiency whilst increasing EPC costs slightly. Therefore the BNE reference CCGT plant GE 9F.05 gas turbine has a revised capacity of 438 MW (previously 447 MW).

2.4.4 Following specific consultation feedback and subsequent review the minimum gas pressure technical assumptions for both an OCGT and CCGT have been updated. In both cases the minimum gas delivery pressure is now 19 bars requiring gas compressors to be considered and therefore costs have been updated to reflect the addition of fuel gas compressors for both OCGT (dual fuel) and CCGT plants.

2.4.5 Following this recent assessment we conclude that OCGTs, both dual fuel and distillate, should continue to be considered the most proven economical technology choice for the reference peaking plant. A wide range of gas turbines were considered and included differing models ranging from 30 MW to 200 MW capacity. Due to economies of scale, the largest capacity units yield the lowest specific costs and therefore the largest unit consistent with meeting the criteria was selected. The OCGT selected as the reference peaking plant has been considered appropriate for the capacity year 2022/23 and the SEM Committee consider the selection of one OCGT model, rather than an average across four OCGT models, as being appropriate for considering the Best New Entrant.

2.5 SEM COMMITTEE DECISION

2.5.1 The SEM Committee is content with the rigorous assessment that has been made of the technologies and the reference plant conclusions made.

2.5.2 Based on Poyry's detailed assessment the **reference peaking plant** considered appropriate for the BNE peaking plant for capacity year 2022/23 is a **Siemens SGT5-2000E.** The average lifetime output is **190 MW on distillate and 198 MW on dual fuel**.

2.5.3 Having considered the most recent gas fired CCGT investments made in Ireland and Northern Ireland the **reference CCGT plant** chosen is the **GE 9F.05** gas turbine, with a revised capacity of **438 MW**.

3. INVESTMENT COSTS

3.1 CONSULTATION SUMMARY

3.1.1 Once the reference technologies were selected, the next step was to estimate the capital investment and annual fixed costs associated with that technology. Taken together with a Weighted Cost of Capital (WACC) a Gross BNE price/Gross CONE value can be derived.

3.1.2 Table 2 and Table 3 below summarise the total capital cost estimates and annual fixed cost estimates for both technologies located in Ireland and Northern Ireland. Chapter 4 of the Poyry report provided tables with a more detailed breakdown.

Table 2: Consultation Summary: Capital cost estimates (€ million 2017 prices)

Jurisdiction	**Ireland**			**Northern Ireland**		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
EPC costs	93.0	92.5	266.6	91.6	92.0	264.6
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	5.7
Water connection costs	0.5	0.5	0.6	0.5	0.5	0.6
Gas connection costs	0.0	3.7	4.6	0.0	3.7	4.6
Owners contingency	4.7	4.6	13.3	4.6	4.6	13.2
Financing costs	1.9	1.9	5.3	1.8	1.8	5.3
Interest during construction	1.3	1.4	5.7	1.2	1.2	5.2
Construction insurance	0.8	0.8	2.4	0.8	0.8	2.4
Initial fill of fuel oil tanks	1.8	1.6	4.3	2.4	2.1	5.7
Project development	5.6	5.6	16.0	5.5	5.5	15.9
Commissioning utilities costs	2.3	2.3	6.7	2.3	2.3	6.6
Operating spares	1.4	1.4	4.0	1.4	1.4	4.0
Accession fees	0.0	0.0	0.0	0.0	0.0	0.0
Participation fees	0.0	0.0	0.0	0.0	0.0	0.0
Total	**119.8**	**122.7**	**338.3**	**118.7**	**122.6**	**337.5**

Table 3: Consultation Summary: Annual fixed cost estimates (€ million 2017 prices)

Jurisdiction	Ireland			Northern Ireland		
Technology	OCGT distillate	OCGT dual	CCGT	OCGT distillate	OCGT dual	CCGT
Trading and admin	0.7	0.7	2.1	0.7	0.7	2.1
Personnel	0.8	0.8	3.2	0.8	0.8	3.2
Insurance	0.6	0.6	1.6	0.5	0.6	1.6
Fixed maintenance	0.5	0.5	1.3	0.5	0.5	1.3
Fixed fee under LTSA	0.6	0.6	1.7	0.6	0.6	1.7
Business rates	1.5	1.5	3.5	0.6	0.7	2.3
Market operator rates	0.0	0.0	0.0	0.0	0.0	0.0
Electricity transportation charges	1.2	1.2	2.8	1.1	1.1	2.5
Gas transportation charges	0.0	0.0	12.6	0.0	2.4	10.8
Total	**5.8**	**5.9**	**28.8**	**4.8**	**7.3**	**25.4**

3.2 SUMMARY OF RESPONSES

3.2.1 In general, respondents were concerned that there was a drive to minimise costs rather than accurately represent the costs and risks of a rational investor.

3.2.2 Concerns were raised regarding both the electrical and gas connection assumptions and costs and a possible misalignment between the location assumptions across a range of costs.

3.2.3 The interest during construction cost was viewed as being underestimated as it was based on the costs of debt alone (40% debt and lending rates of 2.75% and 2.5% for Ireland and Northern Ireland) and didn't allow for the opportunity cost of equity during the construction period. This was considered necessary to represent how a rational investor would consider the opportunity costs of capital over the construction period. This was viewed an important element particularly for a CCGT which requires a longer construction period than the OCGT.

3.2.4 A small number of respondents considered the estimations relating to land costs (particularly in the Dublin area) to be too low. Also it was unclear if the land cost included provision for carbon capture requirements associated with a CCGT.

3.2.5 Gas transportation costs were recognised as a significant cost and therefore respondents were seeking confirmation that the fundamental differences in the treatment of gas transportation in Ireland and Northern Ireland were appropriately reflected in the cost estimates.

3.2.6 Specifically in relation to a CCGT located in Northern Ireland, feedback was received which clarified that a c400MW CCGT would need to connect to the 275kV transmission network rather than a 110kV connection and therefore costs were under-estimated for a CCGT in Northern Ireland.

3.3 SEM COMMITTEE RESPONSE

3.3.1 In general, the capital costs of plant have fallen since 2015, when the last SEM BNE review was carried out. This has resulted in slightly lower EPC contract prices and subsequent costs which assume a percentage of the EPC contract price such as commissioning utilities and insurance. Such cost estimates are based on Poyry's experience of what has been achieved on other similar projects.

3.3.2 Gas connection costs have been reviewed afresh and this decision now reflects the latest estimates received from Gas Networks Ireland for a gas supply pipeline diameter of 8 inches for the OCGT plant and 16 inches for the CCGT plant.

3.3.3 Both the consultation and this decision paper reflect the different jurisdictional arrangements which are in place regarding gas transportation costs. For an OCGT located in Ireland the assumed gas transportation costs are zero for the purposes of this BNE assessment as a rational operator would buy short-term gas capacity rights. As an OCGT (running on gas) in Northern Ireland does not currently have the option to buy short-term exit capacity rights, it will need to buy long-term exit gas capacity rights and therefore this cost is reflected in the annual fixed costs for a dual fuelled OCGT in Northern Ireland. For a CCGT, with assumed baseload/mid-merit operation, it is assumed long-term exit and entry gas capacity rights are bought at the respective charges in Ireland and Northern Ireland.

3.3.4 In response to feedback received the cost estimates associated with a CCGT located in Northern Ireland have been revised upwards to reflect the additional costs associated with connecting to the 275kV transmission system.

3.3.5 Since the consultation it has been recognised that there is also an opportunity cost attached to the equity investment part during construction. Therefore to better reflect a rational investor's opportunity cost of the cost of capital foregone during construction the WACC has now been applied rather than the cost of debt alone. This cost item now assumes a rate of 5.3% for Ireland and 5.4% for Northern Ireland and impacts on the capital during construction cost estimate (previously referred to as 'interest during construction'), particularly for a CCGT which has a longer construction period. Similarly, debt and equity costs during construction are taken into account in the PJM Cost of New Entry.

3.3.6 In general, the land cost estimates are considered reasonable for Ireland and Northern Ireland as a whole and are not intended to reflect specific areas such as Dublin or Belfast. The move to an air cooled condenser (rather than sea-water cooled) for the CCGT plant allows greater

freedom in site location and the land area that was allocated for the CCGT plant (80,000m^2) is sufficient to accommodate future carbon capture equipment.

3.4 SEM COMMITTEE DECISION

3.4.1 Following a review and update of the capital costs and the annual fixed costs associated with the reference technologies the final cost estimates associated with this Best New Entrant assessment are as follows:

Table 4: Final Capital cost estimates (€ million 2017 prices)

Jurisdiction	**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	0.0	5.6	6.1	0.0	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	5.6
Project development	5.6	5.6	17.0	5.5	5.6	17.1
Commissioning utilities	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	0.0	0.0	0.0	0.0	0.0	0.0
Participation fees	0.0	0.0	0.0	0.0	0.0	0.0
Total	**123.8**	**129.8**	**380.0**	**122.8**	**131.4**	**386.4**

Table 5: Final Annual fixed cost estimates (€ million 2017 prices)

Jurisdiction	**Ireland**			**Northern Ireland**		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
Trading and admin	0.7	0.7	2.3	0.7	0.7	2.3
Personnel	0.8	0.8	3.2	0.8	0.8	3.2
Insurance	0.6	0.6	1.7	0.5	0.6	1.7
Fixed maintenance	0.5	0.5	1.4	0.5	0.5	1.4
Fixed fee under LTSA	0.6	0.6	1.7	0.6	0.6	1.7
Business rates	1.5	1.5	3.5	0.6	0.7	2.3
Market operator rates	0.0	0.0	0.0	0.0	0.0	0.0
Electricity transportation charges	1.2	1.2	2.8	1.1	1.1	2.5
Gas transportation charges	0.0	0.0	13.1	0.0	0.9	8.9
Total	**5.8**	**5.9**	**29.6**	**4.8**	**5.8**	**23.9**

4. ECONOMIC & FINANCIAL PARAMETERS

4.1 CONSULTATION SUMMARY

4.1.1 A key component of the calculation of the BNE Net CONE is the determination of the Weighted Average Cost of Capital (WACC). The WACC is combined with the capital expenditure and economic life to arrive at an annualised capital expenditure used in the BNE Net CONE calculation.

4.1.2 Poyry carried out an extensive assessment for each of the building blocks to arrive at a proposed WACC appropriate for the Capacity Year 2022/23. This comprehensive assessment, including assumptions made, was provided in Chapter 6 of the Poyry Report provided with the consultation paper (SEM-18-025).

4.1.3 The different WACC parameters were defined based on a wide range of market evidence and regulatory precedent. However, it was noted that there is limited precedent of regulators setting a cost of capital for a merchant generating unit, as in this case, compared to regulators WACC determinations for infrastructure projects or other monopolies.

4.1.4 Key assumptions made in the WACC analysis are summaries in Table 6 below:

Table 6: Summary of assumptions on the nature of investment

Description	Assumption
Type of Investment	The project is a green-field investment with no existing assets and associated financing costs.
Plant Life	Economic life of 20 years
Financing	The debt tenor is assumed to be 10 years

4.1.5 The Poyry Report (Chapter 6) appended with the consultation paper provided a comprehensive assessment of the WACC building blocks which formed their recommendation of the WACC to be used for the BNE Net CONE for Capacity Year 2022/23.

4.1.6 In summary and at the time of the consultation, Poyry recommended the appropriate range for the real pre-tax WACC for the BNE Net CONE to be 4.5% - 6.6% in Ireland and 4.7% - 6.6% in Northern Ireland.

4.1.7 Within the consultation paper the SEM Committee proposed setting the WACC for Ireland and Northern Ireland as set out in Table 7 below.

Table 7: Proposed real pre-tax WACC

Capacity Year 2022/23	Proposed WACC (real pre-tax)
Ireland	**5.0%**

Northern Ireland	**5.2%**

4.1.8 As the WACC is intended to apply to Capacity Year 2022/23 with a BNE Net CONE defined in nominal terms, the above real pre-tax WACC would need to be converted using an assumed 2% (long term) annual inflation to give a proposed equivalent nominal pre-tax WACC of 7.1% and 7.3% for Ireland and Northern Ireland respectively.

4.2 SUMMARY OF RESPONSES

4.2.1 There were concerns that the proposed WACC significantly underestimates the level of risk associated with the development of power generation assets because, in their view, the WACC is broadly reflective of risks associated with regulated entities and fails to capture the risk profile of merchant investors. Furthermore, the WACC was viewed as not reflecting the increased riskiness of the overall market that the Best New Entrant would be competing in e.g. forecasting risk of inframarginal rent, DS3 revenues together with an optimistic view on load factors for a CCGT.

4.2.2 Choosing a WACC at the lower end of the range is not robust as the WACC has been based on a combination of both market observations and regulatory precedents with the result of increasing the risk of underinvestment. A recommendation was made to choose a point estimate above the mid-point to align with T-4 capacity auction intent to send entry signals to new capacity.

4.2.3 Consideration should be given to WACC estimates adopted in the calculation of Net CONE in GB and other capacity markets.

4.2.4 The same WACC rates are being proposed for both the OCGT and CCGT reference technologies when a rational CCGT investor may expect a higher return for investing in a CCGT given the greater risk associated with capacity cost recovery.

4.3 SEM COMMITTEE RESPONSE

4.3.1 Since the consultation the WACC calculation has been refreshed to reflect more up-to-date information and following consideration of the feedback from respondents.

4.3.2 The cost of debt ranges, which reflect the risk free rate and debt premium, have subsequently been updated. The cost of debt range determined for Ireland is now 2.50% to 5.50% and the range determined for Northern Ireland is 2.25% to 5.00%.

4.3.3 The Equity Risk Premium (ERP) has been refreshed and the ranges are now 4.50% to 5.66% for Ireland and 5.25% to 5.57% for Northern Ireland.

4.3.4 The gearing level of 40% is considered appropriate for this BNE assessment and reflects market evidence for competitive sectors and therefore no change has been made since the

consultation. Applying this gearing level an equity beta range was determined as 0.76 to 1.08 for Ireland and 0.76 to 1.06 for Northern Ireland.

4.3.5 A single WACC assessment has been carried out for both reference technologies, however it is important to bear in mind that technologies which could be considered less risky (i.e. those with lower merchant risk because of a higher proportion of regulated revenues) would be expected to have a WACC towards the lower end of the range with more risky assets towards the higher end of the range.

4.3.6 Within the capacity market a new entrant can apply for a ten year multi-year Reliability Option which should provide a good level of certainty and helps de-risk new projects. This contributed to the SEM Committee selecting a WACC closer to the regulatory precedent, lower bound of the range (with a 75% weighting on the lower bound and a 25% weighting on the upper bound) rather than moving to the mid-point of the range. This change does increase the WACC slightly from the values consulted upon.

4.3.7 Reflecting the above changes, and considering the overall WACC, the SEM Committee consider this WACC assessment appropriate for the purposes of this Best New Entrant assessment within the context of the capacity market and the wider all-island market.

4.4 SEM COMMITTEE DECISIONS

4.4.1 Table 8 below summarises the WACC assessment which results in a real pre-tax WACC of 5.3% for Ireland and 5.4% for Northern Ireland.

	Ireland			**Northern Ireland**		
	Low	**High**	**Mid-point**	**Low**	**High**	**Mid-point**
Cost of debt	2.50%	5.50%	4.00%	2.25%	5.00%	3.63%
Risk-free rate	1.50%	2.50%	2.00%	1.25%	2.00%	1.63%
Equity Risk Premium (ERP)	4.50%	5.66%	5.08%	5.25%	5.57%	5.04%
Asset Beta	0.69			0.69		
Equity Beta	0.76	1.08	0.92	0.76	1.06	0.91
Post-tax Cost of Equity	4.92%	8.64%	6.69%	5.24%	7.93%	6.56%
Taxation	12.5%			17.0%		
Pre-tax Cost of Equity	5.62%	9.87%	7.64%	6.31%	9.55%	7.91%
Gearing	40%			40%		
Real pre-tax WACC	**4.37%**	**8.12%**	**6.18%**	**4.69%**	**7.73%**	**6.20%**
Equivalent Vanilla WACC	3.95%	7.38%	5.61%	4.04%	6.76%	5.39%
Nominal pre-tax WACC	**6.46%**	**10.29%**	**8.31%**	**6.78%**	**9.89%**	**8.32%**

Selected WACC		
	Ireland	**Northern Ireland**
Real pre-tax WACC(%)[1]	5.3%	5.4%
Nominal pre-tax WACC[1,2]	7.4%	7.6%
Nominal post-tax WACC[1,2]	6.7%	6.6%

4.4.2 As the WACC is intended to apply to Capacity Year 2022/23 with a BNE Net CONE defined in nominal terms, the above real pre-tax WACC has been converted using an assumed 2% (long term) annual inflation to give an equivalent nominal pre-tax WACC of 7.4% and 7.6% for Ireland and Northern Ireland respectively.

5. ENERGY MARKET AND SYSTEM SERVICES REVENUES

5.1 CONSULTATION SUMMARY

5.1.1 To arrive at the BNE Net CONE an adjustment is required to subtract non-capacity market revenue streams from the Gross BNE price/Gross CONE. In addition to income from the Capacity Market, a generator operating in I-SEM would be capturing:

- revenues from the energy market(s):
  - a generating unit is expected to capture a certain amount of operating margin, commonly referred to as inframarginal rent, from selling electricity into different ex-ante markets and the balancing market.
- Income for the provision of DS3 System Services:
  - DS3 System Services are procured by the TSOs and potential providers capture a relevant payment.

Inframarginal Rent

5.1.2 The inframarginal rent can be defined as the electricity market revenue net of the short-run cost of operation.

5.1.3 Consideration had to also be given to the expected operation of the new plant, for example, an OCGT would be assumed to be operating as a peaking unit with low number of running hours. Whereas a new entrant CCGT would be expected to run in a baseload/mid merit position in the short to medium term with high number of running hours and low number of starts.

5.1.4 Due to the introduction of the CRM the formula applied previously to SEM BNE calculations for a reference peaking plant had to be revised to reflect the impact of Reliability Option difference payments and Administered Scarcity Pricing (ASP).

5.1.5 If a capacity provider has a Reliability Option (RO) it is required to make difference payments, when the relevant energy price exceeds the RO Strike Price set at €500/MWh. The Reliability Option reduces the inframarginal rent that a generator can earn, so should be taken account in a revised Net CONE calculation. The Reliability Option Strike Price, which will cap the inframarginal rent of a generator with a Reliability Option on the proportion of the capacity covered by the Reliability Option, will be a variable price. However, the DSU Floor Price is set at €500/MWh and unless there is a very significant change in fuel prices, the Reliability Option Strike Price will be €500/MWh most of the time. The €500/MWh value is used in place of the SEM €1,000/MWh Pool Price Cap in the revised BNE calculation, to calculate the inframarginal rent that the BNE plant can earn on the portion of the capacity covered by the Reliability Option. Furthermore, the following also needs to be taken into account, the fact that:

- The BNE reference plant will be exposed to difference payments on the full ASP when on forced outage; but

- Can earn inframarginal rent at the full ASP on the de-rated component of its capacity;
- The introduction of Partial ASP may mean that there are more hours when prices are lifted to €500/MWh or above.

5.1.6 Both the consultation paper and the Poyry report set out the detailed formula applied to the calculation of inframarginal rent for a reference peaking plant (OCGT) which proposed an inframarginal rent of €3.602/kW –installed in nominal money terms.

5.1.7 Inframarginal rent for a CCGT is driven by the operation pattern and the price formation and therefore the calculation applied to the peaking plant is not appropriate for calculating the inframarginal rent for a CCGT. Instead, an average load factor between 65% - 75% was assumed for the reference CCGT for the period 2022/23 to 2031/32, being the ten year Reliability Option period available to new capacity[13]. A key assumption for this is that a new entrant CCGT would have a relatively higher efficiency when compared to existing CCGTs in the all-island market and therefore have a more advantageous position in the merit order and would capture the highest inframarginal rent compared to all other CCGTs on the system.

5.1.8 The Poyry report details further the approach taken for calculating a reference CCGT's inframarginal rent which arrived at a proposed inframarginal rent of €54.5/kW in 2022/23 rising linearly up to €62.7/kW in 2031/32 in real 2017 money terms for a reference new entry CCGT. After 2031/32 the assumption was made that the inframarginal rent decreases by 5% every year to reflect the entry of newer, more efficient units on the system and a decreasing load factor for the reference CCGT.

System Services Revenues

5.1.9 The latest published information relating to the DS3 System Services arrangements was used for the consultation[14]. The TSO recommendation paper provided the implied average annual revenue from regulated tariffs per technology type under two scenarios ('Enhanced' and 'New Providers') with the use of the 'stepped' temporal scalar design. These annual revenues are expressed in €/kW of installed capacity and reflect the average captured income of the entire technology portfolio for Capacity Year 2019/20. The consultation presented the average values across all scenarios for a 'generic' CCGT and peaking plants.

5.1.10 With the DS3 System Services arrangements an expenditure cap of €235 million has been set for 2019/20. For this BNE Net CONE calculation the assumption was made that this expenditure cap of €235 million would remain at the same level in nominal terms post 2019/20 for future capacity years and therefore has been assumed for the Capacity Year 2022/23.

[13] Assumption was a 75% load factor in the first year of operation gradually declining (linearly) to 65% in the tenth year of operation.
[14] DS3 System Services Tariffs for Regulated Arrangements, Recommendation Paper. 23 October 2017 published by Eirgrid and SONI; and
SEM-17-080 DS3 System Services Tariffs and Scalars Decision paper, 24 October 2017.

5.1.11 While a new entrant may have the potential to have more advanced System Service capabilities and is expected to capture System Services revenue greater than similar existing plant on the system, the consultation assumed a more conservative approach be taken. The assumption was to use the average across all cases for each technology type due to uncertainty in calculating future System Services revenues.

5.1.12 The consultation proposed a System Services income value of €14.6/kW – installed for a peaking plant (OCGT) and €7.7/kW-installed for a CCGT as the expected DS3 System Services income for a new entrant reference plant in nominal money terms.

5.2 SUMMARY OF RESPONSES

5.2.1 In general the inframarginal rent calculation was considered appropriate for the OCGT peaking plant, although a comment was made that the OCGT calculation should reflect that the Northern Ireland security of standard of 4.9 hours should be applied.

5.2.2 A common theme throughout the responses was that inframarginal rent plays such a significant role in the setting of the Net CONE for a CCGT, a move to a CCGT as the Best New Entrant technology should not be taken lightly, particularly with the range of uncertainties currently in the all-island market. Reference was made to the PJM market which recently considered both OCGT and CCGT options for their Net CONE evaluation however while the CCGT was the cheapest option the preliminary recommendation was for an OCGT as the BNE reference technology in recognition that an OCGT received the smallest amount of its revenue from the energy market and therefore the OCGT Net CONE value is less likely to be significantly affected by potential changes in the energy market.

5.2.3 There was concern that the CCGT inframarginal rent calculation didn't accurately reflect what participants considered could be captured in the I-SEM and that it was overestimated. Concerns included the linear relationship assumed for full and partial Loss of Load Expectation (LOLE) as in their view the linear rise didn't take account for newer more efficient plant entering the market or increasing penetration of renewables during the period, thereby reducing the BNE inframarginal rent.

5.2.4 Regarding the proposed DS3 System Services revenue there was some concern with the information being limited to Eirgrid's analysis from 2017 being used for a capacity year 2022/23 and also with the use of the average earnings across a technology being applied.

5.2.5 For a unit to be able to provide System Services under DS3 for the duration of a multi-year Reliability Option (up to 10 years) additional capital investment may be required in the first instance together with additional costs to maintain that capability. Such investment and operational costs has been overlooked when considering DS3 in this BNE assessment and therefore, in their view, DS3 revenues have been overestimated.

5.3 SEM COMMITTEE RESPONSE

5.3.1 This BNE assessment is for the purposes of the all-island capacity market and therefore only the all-island security standard has been assumed. For the capacity market this is assumed to be an 8 hour security standard as confirmed in the T-4 parameters decision (SEM-18-155).

5.3.2 The SEM Committee acknowledge the views expressed by respondents in that the CCGT Net CONE relies heavily on inframarginal rent and DS3 estimates which are subject to uncertainties over an estimated 20 year plant life whereas an OCGT is less impacted by such uncertainties e.g. demand growth and renewables.

5.3.3 The CCGT inframarginal rent calculation is based on assumptions for the expected operation (load factor) of a new entry CCGT, commodity price evolution from third party sources (primarily BEIS) and a reasonable estimate for the price-setting technology-on average – at the times when the entry CCGT would be operating.

5.3.4 In light of the consultation responses the CCGT load factor was specifically reconsidered. Actual operation of some of the more efficient CCGTs on the all-island system suggest load factors greater than 70% a few years after the commissioning year. A load factor of more than 65% for the first ten years of operation for a new entry CCGT commissioned in the early 2020s in I-SEM is considered to be broadly in line with Poyry's independent expectations.

5.3.5 Furthermore, It is recognised that when considering price formation, the higher levels of low variable cost renewables can put downward pressure on prices at times of high renewables output. However this does not necessarily entail a corresponding reduction of prices at 'tighter' periods. The total estimated inframarginal rent starting at €45/kW and increasing to €55/kW (equivalent to approximately €5/MWh to €6/MWh clean spark spread on the basis of baseload operation) is a reasonable (if not conservative) estimate of the expected inframarginal rent for a new, efficient CCGT on the all-island system based on the commodity price assumptions used.

5.3.6 The consultation paper noted that the inframarginal rent calculations had assumed the value of Full Administered Scarcity Pricing (ASP) to continue to equal €3,000/MWh while recognising that this value was the subject of the T-4 Parameters consultation (SEM-18-028). The T-4 Parameters decision paper (SEM-18-155) has now set the Full ASP at 25% of Value of Lost Load maintaining the Full ASP at €3,000/MWh.

5.3.7 The approach for estimating the DS3 System Services is based on the latest relevant published DS3 information[15]. Within these DS3 publications an expected income range for an OCGT of €14.1/kW to €15.2/kW and €7.6/kW to €7.8/kW across the two scenarios is presented. For the purposes of this BNE assessment, and to recognise the current uncertainty with regards to the future System Services revenues, a more conservative approach of using the average

[15] SEM-17-017, SEM Committee Information Paper on DS3 System Services Future Programme Approach, March 2017. DS3 System Services Tariffs for Regulated Arrangements, Recommendations Paper, 23 October 2017, Eirgrid & SONI SEM-17-080, SEM Committee Decision, DS3 System Services Tariffs and Scalars, 24 October 2017

across all cases for each technology type, has been adopted. The DS3 revenues are based on a typical unit and therefore allows greater DS3 revenue potential for enhanced capabilities.

5.4 SEM COMMITTEE DECISIONS

5.4.1 The resulting inframarginal rent for a reference **peaking plant is €3.602/kW – installed** in nominal terms.

5.4.2 Having updated the CCGT inframarginal rent assumptions (e.g. CO2, variable operating cost of reference CCGT, etc) the expected inframarginal rent for a reference new entry **CCGT is €51.6/kW in 2022/23 rising linearly up to €55.4/kW in 2031/32 in real 2017 money terms**. Post 2031/32, it is assumed that the inframarginal rent decreases by 5% every year to reflect the entry of newer, more efficient units on the system and decreasing load factor for the reference CCGT.

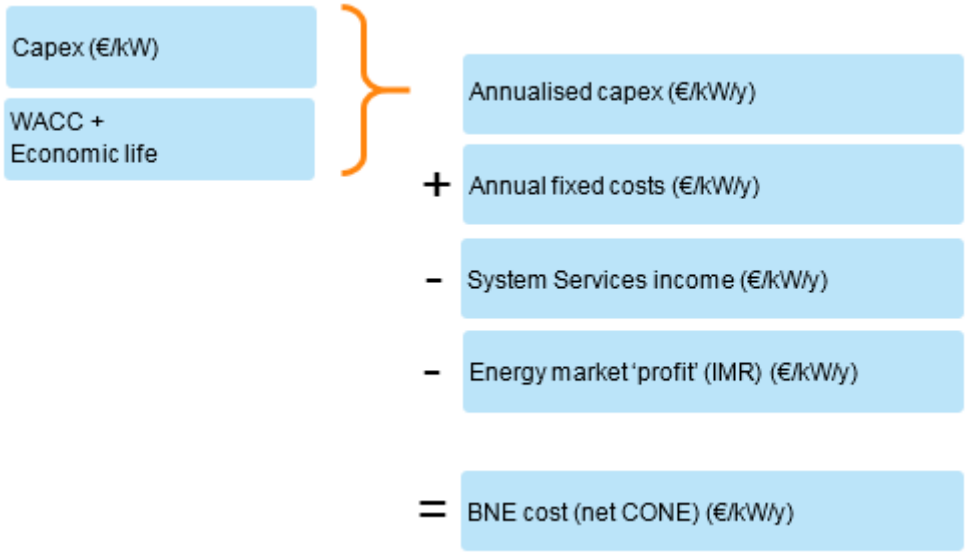
5.4.3 Based upon the latest published information, a DS3 System Services value of **€7.7/kW – installed for a CCGT** and a value of **€14.6/kW-installed for a peaking plant** in nominal money terms as the expected DS3 System Services income for a new entrant reference plant.

6. SUMMARY BNE NET CONE ASSESSMENT

6.1 CALCULATION OF BNE NET CONE FOR CAPACITY YEAR 2022/23

6.1.1 The various components mentioned above are brought together to derive a Best New Entrant Net Cost of New Entry (BNE Net CONE) calculation. This is shown in Figure 2 below and shows the Gross BNE CONE (before deduction of inframarginal rent and system services revenue) and the BNE Net CONE.

Figure 2: Calculation for BNE Net CONE



6.1.2 As this BNE Net CONE is intended to be applied to the Capacity Year 2022/23 the capital costs have been inflated to the year before the first year of operation and a nominal WACC applied. The annual fixed costs presented below reflect the assumption that these costs are expected to continue to rise in line with inflation over the entire economic lifetime of the investment. A long term average 2% inflation for Ireland and Northern Ireland has been assumed for post 2020. As set out in Chapter 7 of the Poyry report a further adjustment is required to define the BNE Net CONE, applicable to Capacity Year 2022/23 in nominal money terms. For the purposes of the Capacity Market the BNE Net CONE is required to reflect the de-rated capacity of the reference technologies.

6.2 SEM COMMITTEE DECISION

6.2.1 The SEM Committee is of the view that the lowest Net CONE value should represent the Best New Entrant as it provides an appropriate expectation of a rational investor within a competitive capacity auction process whilst also being mindful of the need to protect consumers.

6.2.2 Following the consultation the BNE assessment has been updated and includes updates to some assumptions (e.g. location of plant, connection costs) which are detailed further in this paper and also in the accompanying Poyry report.

6.2.3 Table 9 below provides a summary of the 2022/23 Gross and Net CONE estimates for the different reference technologies in Ireland and Northern Ireland alongside the breakdown in the different cost and net revenues building blocks.

Table 9: BNE Gross and Net CONE for Capacity Year 2022/23 (€/kW – de-rated, nominal)

Jurisdiction	**Ireland**			**Northern Ireland**		
Technology	OCGT Distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT dual
Annualised capital costs	76.2	76.5	105.8	76.4	78.3	108.7
Annual fixed costs	43.4	42.5	100.0	35.9	41.7	80.7
Gross CONE	**119.6**	**119.0**	**205.8**	**112.3**	**120.0**	**189.4**
Less: Inframarginal rent	-4.0	-4.0	-73.3	-4.0	-4.0	-73.3
Less: DS3 income	-16.1	-16.1	-8.8	-16.1	-16.1	-8.8
Net CONE	**99.6**	**99.0**	**123.8**	**92.3**	**100.0**	**107.4**

6.2.4 Based upon the above the Best New Entrant with the lowest Net CONE, with a **value of €92.3/kW de-rated for Capacity Year 2022/23, corresponds to an OCGT, firing on distillate, built in Northern Ireland.**

6.2.5 This BNE Net CONE value of €92.3/kW de-rated and the corresponding BNE Gross Investment Cost has been used to inform the following parameters for the first T-4 CY2022/23 capacity auction which are detailed further within the T-4 CY2022/23 Parameters Decision (SEM-18-155):

- **Auction Price Cap (APC):** The maximum price qualified bidders may bid their qualified volume at, and is therefore the maximum price that the auction can clear at. For the T-4 CY2022/23 capacity auction this will be set at a multiple of 1.5 of Net CONE being €138.45/de-rated kW/per year.

- **Existing Capacity Price Cap (ECPC):** A uniform price cap to apply to all existing capacity providers (except DSUs), with the exception of those who apply and receive a Unit Specific Price Cap. For the T-4 CY2022/23 capacity auction this will be set at a multiple of 0.5 of Net CONE being €46.15/de-rated kW/per year.

- **New Capacity Investment Rate Threshold (NCIRT):** The amount that a new investor must invest per de-rated MW of capacity to qualify for a multi-year Reliability Option. This parameter is approximately based on 40% of the gross BNE investment cost. For the T-4 CY2022/23 capacity auction this will be set at €300,000/de-rated MW.