Capacity Remuneration Mechanism (CRM) T-4 Capacity Auction 2022/23 Best New Entrant Net Cost of New Entrant (BNE Net CONE)

SEM-18-025

Introduction

SSE welcomes the opportunity to comment on the SEM Committee's (SEMC) Consultation Paper, regarding the setting of the Best New Entrant (BNE) for the first T-4 CY2022/23 capacity auction.

SSE has over 2,000MW of operational generation capacity and 750,000 retail customers across the island of Ireland. The priority for our generation business is to deliver flexible, sustainable, cost-effective energy, through a diverse portfolio of generation assets. We own and operate the newest and most efficient gas fired plant in the market. We are fully committed to investing further, and are currently progressing additional flexible generation, to ensure Ireland meets its energy needs. As a large-scale generation project developer, we are uniquely placed to comment on the SEMC's proposals on the BNE.

Under the I-SEM, a stable, well-designed Capacity Remuneration Mechanism (CRM) should ensure that sufficient, efficient capacity is available to the market for security of supply purposes. It should also ensure that generators can obtain an equitable return on their investments. The intent of the BNE Consultation Paper is linked with the purpose of the T-4 CRM auctions, which is the first capacity auction to realise economic entry, and long-term exit signals, for new generation on the system.

At a time when plant will be required to close due to factors such as environmental obligations, it is critical that entry signals are at a level that ensures efficient new entry is sufficiently rewarded for the risk undertaken, in relation to the large-scale capital expenditure.

Executive Summary

This response focuses on the key inputs and assumptions used to calculate the BNE, as below.

1. SSE is concerned that there is a disjoint between the RAs intention to signal a CCGT as the reference plant and the real-world ability of generators to deliver such plant prior to CY2022.

2. The development of the cost inputs, including calculation of applicable WACC are not robust, and lack a consistent approach between a notional location and a specific location. We are particularly concerned about the methodology employed by Poyry to develop the electrical and gas connection cost, gas transportation costs and turbine type.

3. A developer of generation assets must ensure that it can cover the cost of capital associated with the project. Poyry have grossly understated the risk associated with the development of power generation assets. SEMC has by and large indicated a regulated entity WACC as applicable to the BNE, which fails to capture the risk profile of debt/equity of merchant investors. We also note that SEMC has proposed a point on the range of WACC, as recommended by Poyry, which is at the lower end of that range. This increases the risk of underinvestment at a time when new generation assets are critical for maintaining security of supply.

4. With regards to the IMR, the methodology employed does not accurately reflect what an OCGT or proposed CCGT, will be capable of capturing in the I-SEM. Particularly concerning are the proposals regarding the IMR associated with full and partial LOLE, and the linear rise expected in IMR for a CCGT, during the period. This linear rise does not account for newer more efficient plant entering the market during the period, thereby offsetting the proposed BNE IMR. The calculation of the IMR is a significant component which impacts on the level of risk associated with a generation project. This in turn impacts on the risk that investors require remuneration on in the cost of capital.

This consultation response

This response is in addition to our participation within the EAI industry response, some of which we reference below. SSE's response provides our comments on the following:

- The dichotomy of a theoretical BNE vs. the intention for a real world, timely investor signal driven by the new BNE
- The feasibility of plant chosen for the BNE reference plant
- The replicability of the costs inputs used to construct the BNE
- Weighted Average Cost of Capital (WACC) estimated for the calculation of the BNE
- Inframarginal rent (IMR) estimated for the proposed CCGT and OCGT
- The impact of the new BNE on certain parameters of the CRM

In addition, we note that many of the proposals outlined in the BNE paper lack substantive background assumptions, which means we cannot fully comment. We have therefore included additional queries which we would appreciate clarity on, as part of the final decision paper.

We note that the BNE consultation has significant interaction with a parallel SEMC consultation proposing changes to the T-4 parameters, SEM-180-028. We reference SEM-18-028, within this response, below. SSE intends to respond to that consultation in due course, and will equally reference any interactions with the BNE.

The feasibility of choice of reference plant

We note that the reference plant for the first T-4 auction is being proposed to be a CCGT, rather than the precedent of setting the BNE as an OCGT running on distillate. Whilst we acknowledge the intention of this shift to reflect recent investment decisions, and encourage new entry to meet future needs, we believe that its construction and comparison against a backward looking[1] OCGT, overstates its feasibility**.**

Timeframes for delivery

The CRM T-4 auction requires new generators to be available from capacity year 2022. Given that the lead time for a new build CCGT includes external factors such as connection to the gas transmission network, it is imperative that the intended signals from SEMC, match the ability of the market to feasibly deliver on such market signals. On this basis, we are of the view that given the differential in time between the delivery of a distillate plant vs. a gas fired plant, the differential means that it is not feasible to build a CCGT in the proposed timeframe.

In addition, a baseload/mid-merit plant by its nature, would require a more complex investment case. It would be expected to obtain more of its revenues from the energy and system services markets, with associated risk, and therefore its feasibility in relation to the capacity market is diluted, when this is considered.

Location/characteristics

A new CCGT entering the market will have an impact on already falling load factors of existing CCGTs, which may represent an incentive for more OCGT to enter the market, (unless other aspects of the energy market change). The load profile of the proposed BNE, also being mid-merit or baseload, makes it a relatively inflexible new entrant regarding location and infrastructure needs, thereby affecting investor decisions. SEMC's observations regarding new entry likely siting at the location where plant

[1] (i.e. the reference calculations to develop the OCGT scenario are based on old SEM BNE approach)

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have exited the market (see SEM-18-028), is most relevant to the siting of a CCGT BNE, thereby affecting investor decisions, and making the location-specific characteristic of the BNE, inappropriate.

If, the intent is for capacity to enter the market in Northern Ireland specifically, such as may be suggested by certain published generation forecast scenarios, we consider that this represents a narrow and potentially risky reliance. The intention of a BNE should be constructed on a non-site-specific basis, to reflect a positive signal for entry, all-island, based on the actual network constraints at any given time. We note that some of the BNE cost inputs costs (e.g. electrical connection and economic life) are based on a "*notional rural location*". Other element of charges, also based on a notional location (i.e. 2km for a gas connection), would appear to contradict this, as they must *de facto* be more location-specific than notional, (given such a short gas connection assumed, even from a rural site in Northern Ireland). This ultimately contradicts the intent of the BNE to be all-island comparable.

In addition, as SEMC discusses in SEM-18-028 consultation (regarding locational constraints), there is a great deal of uncertainty as to where new entry with situate itself. There appears to be an assumption that brownfield sites would be the most likely choice, regardless of location or jurisdiction (i.e. that capacity would likely site where other capacity has exited). It is essential for there to be clarity and consistency regarding the intention and effect of the BNE (be it site-specific or not), and other CRM parameters, in the round.

Turbine type

We have observed that the selection of the type of reference technology for the CCGT is an F class turbine. Poyry constructs its gas turbine models based on those considered for the last BNE and types of CCGTs operating in the market presently, (i.e. representing recent investment decisions made for new CCGT).

The turbine model selected, likely does not take account of commissioning of more efficient plant (i.e. EU Ecodesign Directive[2]). There is therefore a risk that the BNE reference plant is not providing realistic entry signals, in not adequately considering the likely efficiency requirements of plant, over the economic life of the BNE. We also note Frontier's comments in relation to the isolating of a specific turbine manufacturer for the BNE.

BNE Net CONE inputs

We have conducted our own assessment of specific cost inputs, which we consider will change the overall view of the costs associated with a CCGT or OCGT. Broadly, we believe certain Capex and fixed annual costs have not been accurately estimated, (or do not capture certain key considerations that should affect Poyry's estimates). These inputs need to be carefully considered and updated as part of the final decision.

Electrical connection

The electrical connection estimated by Poyry assumes a 5km overhead connection (220kV ROI and 110kV NI), from a *notional rural location* to an existing substation, requiring a two-bay extension to that substation.

We assume that the connection would be completed contestably and therefore, we have reviewed SONI's and EirGrid's Statement of Charges[3] to an existing TSO substation. We arrive at differing estimates for plant sited in both jurisdictions. We request clarity in the final decision on the exact elements that make up the indicated electrical connection charges.

[2] http://ec.europa.eu/growth/industry/sustainability/ecodesign_en
[3] http://www.soni.ltd.uk/media/SONI-Transmission-Connection-Charging-Methodology-Statement-Effective-1-Sept-2016-Approved-by-UR.pdf

Gas connection

The gas connection estimated by Poyry assumes a 2km connection, from a *notional rural location*, to the network. It is unclear where the 2km assumption has come from and this reflects on the issue of whether the BNE is intended to be site-specific or notional.

We also question why more recent cost data has not been used. The data used is from 2010, and is therefore capturing a time when steel indices were comparatively low due to reduced demand. In addition, as steel is the largest cost of construction of gas transmission pipelines, it does not trend against the general inflation rate. As such, Poyry is using information that is 8 years out of date. This needs to be updated to reflect the actual costs associated with steel for a CCGT building between 2018 and 2022. Poyry also references *"in house knowledge and similar gas pipeline projects,"* in arriving at their estimates. Publicly available, indicative prices suggest a c.10% increase in raw materials (excl. freight costs), since 2010 (Platts).

For an OCGT, a specific diameter of gas pipeline is assumed by Poyry. However, for a CCGT, a *"larger diameter"* is referenced. Therefore, we cannot reproduce the costs, as we are missing one variable, (i.e. diameter), in order to calculate the cost.

Finally, it is not clear that the costs of compression equipment necessary to offtake the gas for the plant, are included or not. We estimate these could be in the range c.€2m.

LTSA

Poyry assumes a split of 70% variable and 30% fixed LTSA. For a baseload/mid-merit plant, such a split is unrealistic. A CCGT is more likely to have a split of 40:60, which will therefore result in a higher cost than that which is estimated.

Existing LTSAs for a CCGT would typically be referenced to running hours and starts, of which only a proportion can be isolated as variable and recovered through a start-up cost. The primary variable cost would be that reflected in no load costs.

Other costs

We note that Accession and Participation costs do not appear to consider SEMOpx (Power Exchange) or ECC (clearing bank) fixed costs. In consideration of the fact that the DA and the ID markets are the sole route to market, it is imperative that these fixed (and associated working capital) costs are included in the assumptions, as they are costs faced by generators.

TUoS/SSS charges

In relation to TUoS or SSS charges, we note that Poyry's assumptions are premised on the revenues outlined in the respective Price Controls for EirGrid and SONI. This does not appear to take account of those revenue increases that may reasonably be expected, as a result of potential pension deficits, which would increase required revenues.

In addition, as stated in the SEMO Price Control Consultation Paper, it was expected that a publication of the I-SEM implementation costs would be published by the SEMC, and that the costs of I-SEM would be recovered via the respective Price Controls. To date, we have not seen any publication in relation to these costs, but can only assume that these have not been factored into TUoS or SSS charges. Based on the costs seen by market participants in market readiness, we can only assume that the costs to be recovered by the TSOs will be significant enough to have a material effect on TUoS and SSS charges.

Gas Transportation Costs

In the case of both jurisdictions, gas transportation costs make up a high proportion of the overall annual costs. For Ireland, gas transportation costs make up c. 44% of the annual costs, and for Northern Ireland they comprise c. 43%. Accordingly, gas transportation costs are a significant cost factor, when considering where to site a CCGT plant.

In Poyry's assumptions, regardless of jurisdiction, a CCGT will optimally book 80% of its required gas capacity through "long term rights" i.e. annual capacity requirements. In our view this blunt assumption does not recognise fundamental differences between gas transportation in Ireland and Northern Ireland.

Assumptions on Annual vs. Short term gas capacity

In Northern Ireland, entry capacity was introduced for compliance requirements with the EU Network Codes, particularly, Capacity Allocation Mechanisms (CAM), which required short-term capacity products to be available at Interconnection Points. On this basis, Utility Regulator introduced Short-term multipliers for entry capacity, which mirrored those in Ireland. Where a CCGT were to buy only Daily capacity, then it would pay 189% of the annual capacity product. Where a CCGT were to buy only Monthly capacity, then it would pay 155% of the annual capacity product. *Prima facie* this would seem inefficient vis-à-vis the annual capacity product. However, this is dependent on the running profile of a CCGT generator.

As Ireland progresses towards increasingly higher levels of both renewable and interconnection, it is not unreasonable to assume that the running time of gas fired generators in the energy market will require considerable flexibility. As a result, SSE does not agree that an 80% annual capacity booking assumption is reasonable, if the CCGT in question expects to have a 75% load factor. To achieve this, it would need a higher capacity booking at both entry and exit. If it did not book in this manner, then during winter, it would incur a substantial cost from booking short-term capacity, that would erode its IMR and running hours.

Poyry's assessment contains no narrative on the difference in the gas Exit regimes in Ireland and Northern Ireland. In 2016, Utility Regulator undertook a review of the lack of Short Term Capacity at the Exit in Northern Ireland. The outcomes of that consultation process indicated that respondents were of the strong view, that the unavailability of short term exit capacity in Northern Ireland was an *"impediment to new NI gas generation"*. As such it is difficult to reconcile how the BNE paper is of the view that a CCGT sited in Northern Ireland is more reflective of "actual market outcomes", when there is a clear indication from the market, that the lack of short term capacity at the exit, is an impediment to investment.

Finally, the EU Network Code on Tariffs will require a review of Short term multipliers. This may also impact on the ratio of annual short-term capacity that a generator buys in the Irish or Northern Irish gas markets. Dependent on the level of entry/exit multipliers in place, this could affect the competitiveness of plant siting in either jurisdiction. This is particularly important in the context of Northern Ireland potentially diverging from EU mandated requirements, post Brexit.

WACC

We have reviewed the inputs for the WACC calculation, and have included some broad queries specific to SSE, as well as some observations regarding the inputs to the WACC. Most significantly, we note that recent regulatory decisions have been used as inputs to construct the WACC. We consider this approach is less applicable to merchant generators, who incur the full risk associated with an unregulated generation business. Please see details below.

It is worth noting, that the T-4 auction is the first long-term auction under the new I-SEM, and by its nature, is the first to give entry signals to new capacity via a competitive auction process. As such, the calculation of the WACC is imperative, as it should accurately reflect the risks that a generator will face when entering the capacity auction, where revenues are not guaranteed. A prudent investor who wishes to ensure recovery of their investment, will factor this into the cost of capital at the outset of a project.

Queries and clarifications

Section 6.1.4 of the Poyry supplementary report which outlines their approach to WACC, is confusing. It explains two separate approaches using nominal money for a nominal WACC or real money resulting in a real WACC, with an indexation mechanism for inflation. For the actual WACC calculated for this consultation, clearly this is a nominal WACC, adjusted by 2% inflation for the period. However, the inputs used, appear to be in real money terms (i.e. 2017 terms), for a nominal WACC—which is inconsistent. Clarification on the application of real vs. nominal values, would be welcome.

Section 6.1.4. goes on to query who bears the risk of inflation. The capacity market clearing price does not provide any protection with regards to inflation. Therefore, the full commercial risk is born by investors. This level of risk doesn't appear to be considered in any of the metrics developed under cost of capital, even though there is no such protection under the capacity market. Furthermore, there is no indexation mechanism to adjust the WACC over time. The WACC is a significant cornerstone on which the BNE is estimated, and therefore makes the estimated CCGT BNE proposed, more tenuous.

Providing a range for the WACC

Poyry have given a range between 4.5% and 6.6%, and have provided the recommendation of 5.0% and 5.2% which is *"based on analysis"*. However, the report does not elaborate on why these figures have been chosen. Analysis from Oxera indicates that regulators have tended to choose a point estimate in the range above the midpoint. This is to ensure against the potential for underinvestment. Applying this logic to the SEMC decision to apply a WACC below the midpoint seems counterproductive to the intent of the CRM T-4 auction, which is to send entry signals for new entry.

Whilst the risk of underinvestment may not matter in certain sectors – i.e. if no new capital investment is expected or required, the WACC could be set at a lower level than the midpoint, in the case of CRM, the purpose is to ensure that security of supply is met across the island via the necessary installed capacity, which should translate into a midpoint/high view.

In addition, we are of the view that given the lack of certainty over Brexit, particularly the status of Northern Ireland, it is essential that any WACC calculation take account of such considerations.

Using a regulated WACC as a proxy for merchant projects

In addition to the WACC range used, SSE has concerns regarding the proposed WACC itself. As outlined above, Poyry have relied on regulated entities as the basis for developing the proposed WACC. This fails to consider that the risk profile for a generator is different from a regulated entity. For example:

1. The CRM provides only a partial route to recovery of costs, both in terms of the actual Reliability Options payments and in terms of the recovery period (10 years). The investment case for a CCGT would typically be made on a 20 to 25-year basis.
2. Assumptions are made that non-CRM revenue would also arise, particularly associated with IMR and DS3. As per other sections of this consultation response such assumptions may not materialise for generators and entail substantial market risk.

On this basis, we are of the view that SEMC have underestimated the level of risk, and hence appropriate WACC associated with such projects. Below we set out our views in relation to specific aspects of the calculation of the WACC, as proposed by Poyry.

In line with expectations, Poyry have utilised the CAPM model to calculate the relevant WACC, which is standard practice. Whilst we agree that projects are typically financed through a combination of debt and equity, we are of the view that the calculation of the components that make up the WACC is not robust. This is on the basis that Poyry have combined both market observations and regulatory precedents, to determine the appropriate WACC.

We recognise that the estimation of a WACC is dependent on the profile of risk that a particular entity faces, and therefore there is a difficulty in determining what is appropriate across a range of investors. However, recommended levels of equity risk premium and gearing require considerable consideration.

In the case of the Equity Risk Premium, Poyry undertake an assessment of the Credit Suisse returns as well as considering the ERP from regulated entities. Poyry appear to base the ERP on the regulated ERP. However, SEMC has decided to focus the BNE on a gas fired CCGT with considerable risk around the calculation of the IMR. As such, we do not agree that the level of equity risk for investors vs. the risk-free rate, is at a reasonable level.

In the case of the gearing we are concerned that the Poyry report takes an estimate of the applicable gearing for market participants, which is based on a snapshot in time rather than based on the latest evidence of the market. The 40% gearing level would not reflect the actual project finance economics of any recent new build CCGT. The Trafford CCGT plant that secured a capacity contract in the first GB T-4 auction was unable to secure financing, noting that investors remain very concerned about the uncertainty of merchant revenues for new CCGT projects.

In addition to our comments above, we have further queries relating to values provided and assumptions for the WACC, see below. We would also welcome a worked example to understand how the WACC, Economic life and capex, flow into the calculation. This is not clear from Figure 1 in the Poyry supplementary report.

Additional queries

1) Where were the figures sourced for SSE's equity beta and gearing? Neither of them align with the figures we have used as a group.
2) What methodology was used to calculate gearing in Figure 7 of the Poyry supplementary report? We note the reference to the CMA, UK based benchmark and the reference to regulated gearing.
3) Has the uncertainty around Brexit and the future of the I-SEM been considered? It does not appear to have been. We would consider this to be a critical factor that a rational investor would consider as increasing risk, and therefore should be factored in to the WACC calculation.

Inframarginal rent (IMR)

There are significant interactions with the parallel SEM-18-028, reviewing the CRM T-4 parameters, (specifically proposed changes to ASP and LOLE). The proposed changes to ASP and LOLE, will significantly affect the IMR estimated here and therefore, the conclusion that a CCGT should be the reference plant for BNE. There is no reference to this interaction, or indication of the approach to the BNE, should SEM-18-028 affect the assumptions and calculations set out in the BNE paper.

Broadly, the IMR calculation assumes certain values for full and partial ASP, when these and other relevant considerations for IMR, are under review. The ASP values used are 8 and 4 hours, respectively. We consider that if you take account of relevant delivery year and locational constraints that need to be procured, the unconstrained auction would clear at the cap of 0.5 ECPC, with some proportion of constraints being met in addition. Therefore, a single 4-hour assumption is more realistic for the 10-year delivery period in question, rather than the 8 Full + 4 Partial figures, assumed.

IMR OCGT

In the case of the reference OCGT, the IMR appears appropriate, though this is also contingent on the landing position for the ASP and LOLE being proposed in SEM-18-028. The IMR calculation for the OCGT also relies on the use of the previous SEM view of IMR, rather than perhaps imagining an appropriate formula for the I-SEM, since the overall approach to BNE Net CONE has shifted. Presumably, the BNE being a mechanism to encourage new entry, should not detrimentally affect the entry of other (non-reference) plant to the market.

IMR CCGT

In the case of the CCGT plant, the IMR is estimated to rise on a linear basis over the 10 years, despite load factors reducing from 75% to 65%. This does not appear credible, as it seems to suggest that the CCGT will increase both its efficiency and capture factor over time. The first does not reflect degradation of the CCGT, and the second implies no new build to compensate for generator exit. While we can understand the post 10-year assumptions, we have been unable to clearly reproduce the IMR calculations that give rise to this increase within the initial 10-year period.

We have nevertheless sought to try to unpick this rationale for the linear rise over the 10-year period. It appears that Poyry's calculation overestimates the value of carbon, considers that coal will be expensive and gas cheap. We consider that this does not reflect the range of price scenarios that would be considered by the BNE investor, in reaching a central case price forecast. An optimistic view of carbon, such as that of BEIS, does not come close to whatever value of carbon must underpin Poyry's assumptions, to produce a linear rise in IMR[4].

Furthermore, a linear rise is unrealistic, given that the CCGT will be displaced in the merit order by new, more efficient plant entering the market and undercutting the IMR received by plant available for 2022, and specifically when the assumed penetration of renewable energy increases to meet climate change targets. All of this will impact the IMR captured. Finally, potential future interconnection with Europe may also undermine conventional plant and (may not have been included in the calculation of the IMR).

System Services

[4] https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2017

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/671191/Updated_short-term_traded_carbon_values_for_modelling_purposes.pdf

We note that System Services are quoted in nominal terms referenced to 2019/20, rather than real 2017 terms like the rest of the inputs to the paper. We would request clarification, given the difference in nominal years applied (i.e. 2017 terms for IMR inputs, vs. System Services).

CRM mechanisms

We acknowledge that the intention for the BNE is to incentivise new more efficient plant entering and expecting to capture a large share of the market, as a mid-merit/baseload plant. However, at the same time, the CRM mechanisms of APC and ECPC are being kept consistent with the approach used for the near-term focused T-1 auction process.

APC provides an indication of "headroom" which can provide encouragement for new entry. However, ECPC is the actual return that generators get for volume (unless a higher USPC is applied by a specific generator). As it currently stands, the ECPC multiplier of 0.5 could be seen to be providing an equal, opposite signal towards exit, at the same as the proposed BNE Net CONE intends to provide an equally strong signal for entry. This provides confusing signals for investment and returns beyond simply responding to the call to enter the market. We note that the ECPC and APC are being considered as part of a parallel consultation, therefore, we will provide additional comments in our response to SEM-18-028.

Following the first T-1 auction, only 75% of plant appeared to be covered under the current ECPC cap set at 0.5 of BNE Net CONE. There is a significant risk that under the changes to BNE Net CONE, and

the entry of a large efficient CCGT, that, as it currently stands, the ECPC at 0.5, will miss more than 25% of plant.

This indicates that the ECPC is inappropriate, as it suggests that a large proportion, (rather than an exception), of installed capacity is inefficient. This proportion may increase as a new CCGT displaces existing capacity. This could result in an unintended exit signal to existing useful capacity.