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

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About Grange Energy Centre

Grange Energy Centre (GEC) is a planned 96MW power plant located within Grange Castle Business Park (GCBP) in South County Dublin. GEC expects to be a potential new generation capacity provider in the upcoming T-4 auction.
The legal entity of Grange Energy Centre is Grange Backup Power Ltd.

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1 Introduction

Grange Energy Centre (GEC) are pleased to respond to the consultation on Capacity Remuneration Mechanism (CRM) T-4 Capacity Auction for 2022/23 Best New Entrant Net Cost of New Entrant (BNE Net CONE) (SEM-18-025).

2 SEM-18-025 Consultation Question and Response

"The SEM Committee welcomes views and responses on any aspect of this consultation paper and the appended Poyry report. However, the overriding question is: Do respondents agree that the Best New Entrant applicable for the competitive capacity auction process should be the reference technology analysed which results in the lowest Net CONE (based upon the analysis for this consultation the BNE Net CONE is proposed as a CCGT located in Northern Ireland)?"

Grange Energy Centre asks the SEM Committee to reconsider the concept of best new entrant. There are a number of weaknesses in the concept and method by which BNE is assessed, that make it less applicable to the iSEM Capacity Market.

BNE determination is a highly theoretical and wide-ranging process which leads to outcomes that are not a reflection of market developments and in particular the requirement for flexibility in new generation plant.

It is the stated desire of the SME Committee that "*BNE assessment going forward.. should more generally reflect the technology and cost decisions a rational investor would take within the all-island market*". This consultation process provides the opportunity to do just that.

We are particularly concerned that investment in large scale relatively inflexible stranded assets (e.g. 447MW CCGT) is seen as the most rational choice for an investor in iSEM, rather than fast flexible, low-carbon and modular generation capacity. It is noted that the regulatory authorities share the view that flexibility is required to accommodate renewable energy, as described in the capacity market State Aid Decision[1]:

[1] http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_44464

"the authorities explained that the high and rising levels of intermittent renewable generation combined with the limited potential for demand response as well as the relatively limited interconnection .. mean there is a great need for flexible generation that can respond when renewables are not available – for example gasfired power plants."

Our concerns with the approach to BNE Net CONE are set out below:

2.1 Relevance of CCGT in Market that Requires Flexibility

A 447MW CCGT located in Northern Ireland is deemed to be the most relevant solution for the capacity market. We do not agree with this position, taking into account the following:

- The rationale put forward that this is representative of historic investment trends under SEM is no longer applicable due to the radical market changes proposed under i-SEM.
- A CCGT is very inflexible by comparison with other potential capacity or system service providers. It is no longer acceptable to be relying on baseload energy sales, market flexibility is the most important criteria. CCGT units typically have a min. gen, depending on the type and model of ~40%. The CCGT plant needs to be deployed at a large scale (400MW+) to be financially cost effective (in particular to carry the high fixed costs).
- A dual fuel gas engine by comparison can be installed in modular units of 10MW, and with a min gen of ~20%, or just 2MW.
- The concept of using a new CCGT with a minimum baseload requirement of 178MW to deliver flexible capacity solutions is not commercially sound.

Apart from the technical and business concept risk, the location of Northern Ireland carries no risk or location weighting, and the following should be considered:

- In theory the location is irrelevant due to the SEM. The practical reality is that the majority of demand is in Dublin and the expected future growth is in the Greater Dublin region. The most constrained capacity area is expected to be Dublin. It is therefore illogical that a plant in NI is the most relevant example for new investment by a rational investor in the all-island market.
- There is also the political and economic risk associated with basing an economic scenario around a plant located outside the jurisdiction where most demand is required on the system.

The scale of financial commitment involved in a CCGT would also be a significant deterrent to market-entry. It would be more logical for consumer and generator alike to select a new investment with lower initial and ongoing cost commitment:

- The CCGT capex at €337 million is an order of magnitude higher than the capital to be deployed for an OCGT (€118m)
- The ongoing fixed cost commitment for the CCGT is €25.4m vs €4.8m for OCGT
- According to the CONE assessment, a CCGT would have an annual cost base of €175.7/kW/year which has to be largely recouped through inframarginal rent.

It is noted also that Poyry estimates that a CCGT coming on load in 2022/23 would enjoy a 75% load factor and then declining by 1% per year to 65% over the first 10 years of its life. Poyry made a best guess at a Load Factor of 75% rather than modelling it. Obviously the higher the load factor the lower the CONE, and it is appropriate to query the robustness of the load factors in a market that prioritises market responsiveness over being being on-load.

2.1.1 Poyry CCGT Cost Assumption Queries

Apart from the applicability of the identified solution not being appropriate to iSEM, there are a number of items in the BNE costing as assessed by Poyry which should be re-evaluated or queried.

Grid costs: In our opinion and that of our consultants (Mullan Grid), the assumptions around CCGT connection method and costs in NI is not accurate.

It is unclear why Poyry assessment assumes 110kV costs for NI and 220kV costs for RoI. A c.400MW CCGT in NI will need a 275kV connection. The maximum generation that could connect at 110kV is c.150-180MW. All existing CCGTS in NI are connected at 275kV.

We include below Mullan Grid's connection cost estimate at 220kV for ROI:

RoI	Cost (€m)	Source
Looped 220kV substation	€ 3.80	2015 CER approved Transmission charges
2 x 220kV bays in existing 220kV substation	€ 2.58	2015 CER approved Transmission charges
2 x Common Station costs in 220kV substation	€ 2.56	Gate 3 connection offer
2 x 5 km of 110kV 220kV OHL	€ 7.70	2015 CER approved Transmission charges
220kV Substation Civil Works	€ 1.50	estimate
Total Grid Connection Cost	€ 18.14	

This cost is more realistic and is over 200% higher than the €5.7m assumed for the technically non-viable 110kV connection of a large CCGT.

We have not included in above table, but are of the view that over head lines have become unpalatable from social acceptance point of view and that most investors would expect to incur the additional cost of burying these lines.

Land costs: Our own experience of land cost in industrial zoned lands where a rational investor might wish to locate a power plant indicates that the €150k estimate for Ireland is too low and that €350k per acre is a more realistic cost.

Gas Connection Costs: The gas connection costs do not include any reinforcement of the gas transmission network. It is extremely likely that any new entrant would have to incur an additional €1.5m for upgrade of the nearest AGI (Above Ground Installation) to accommodate the additional capacity. The Poyry estimate of €5.1m to connect a CCGT is therefor underestimated by about 30%.

Grid O&M costs: It is unclear what annual grid O&M charge has been included in NI and RoI. This would be approx 1.5-2% of the connection cost per annum. For a connection cost of €18m, this would represent an annual cost of c. €350k.

Electricity own consumption and import: It is **u**nclear if import electricity costs are included in the annual cost estimates. These can be substantial, especially in RoI with PSO costs. In a scenario where a large scale unit is running at min gen or standby, the own electricity cost overhead remains relatively constant and does not decrease pro-rata in line with MW output.

2.2 Relevance of Assessed OCGT Peaking Plant

A peaking plant assessment was included for the analysis based on historic provision of capacity under SEM. The lowest cost peaker reference plant selected is a 188MW OCGT running on either distillate or Dual-Fuel (Gas/distillate).

Why does the SEMC persist with analysis of a distillate-fired OCGT plant when there is a shift away from distillate usage. The SEMC should be looking at dual fuel gas-fired plant only in its deliberations for BNE/CONE.

The size of the unit is out of keeping with historic or expected future peaker unit sizes. The units historically deployed are mostly ~50MW scale (e.g. Swiftpac 50 (52MW) at Rhodes and Tawnaghmore and Swiftpac 60 at Edenderry (58MW)).

It is much more likely that smaller-scale flexible peakers would be deployed, rather than make a commercial commitment to a single €118m peaker unit. It has also been observed historically that relatively smaller units can be relocated (e.g. movement of Swiftpac 50 from Aghada to Tawnaghmore), and that this would obviously be more likely for more modest size units.

2.3 Idealised concept of BNE and using CONE as bid cap

The concept of using BNE to set a price cap assumes a perfect market, which is flawed and not compatible with an open and fair auction. It is a reasonable expectation that only the most competitive bidders would have a similar cost base to the lowest cost new entrant (as assessed under the BNE process), and that the majority of bidders would have a cost base above the hypothetical and idealised scenario of the BNE.

CONE is derived from the Best New Entrant (BNE). The level of BNE and CONE has a decisive impact on new entrants in the capacity market. One of the options under consideration in SEM-18-028 is to have an effective price cap of CONE for bidders requiring more than 1 year of capacity commitment. This would certainly apply to all new plant investment to participate in the capacity market.

This is not consistent with the State Aid Decision (Case 44465)[2] which clearly set out that new generators could bid up to 1.5 CONE, not mentioning that this should be restricted to single year bids:

"Demand-side response operators and new capacity… can bid up to the market wide auction price cap (1.5 x Net CONE)" – recital 50, State aid No. SA.44464 (2017/N).

Furthermore, the EU Commission based their state aid decision on the basis of a 1.5 X CONE cap (Not 1 x CONE):

"The Commission in addition considers that the fact that the full investment of new entrants must be recouped is already taken into account in the bidding caps, since new capacities can bid up to 1.5 Net CONE" – recital 137, idem

[2] http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_44464

To not allow multi-year bids above CONE is placing an unreasonable expectation on new entrants that they must have an investment case that is as good as or better than the notional Best New Entrant.