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30 November 2022

RE: SEM-22-076 - Consultation Best New Entrant Net Cost of New Entry

Dear Merin and Donna,

Bord Gáis Energy (**BGE**) welcomes the opportunity to respond to this consultation on the Best New Entrant (**BNE**) net cost of new entry (the consultation).

1. Executive summary

BGE fears that as an industry we are procuring the wrong type of capacity to meet our decarbonisation objectives. The market as currently designed is not incentivising investment in efficient, renewable ready generation and we risk locking in unsustainable dispatchable generation. Certain recent market outcomes are pointing to this reality demonstrating that focusing on the cheapest cost outcomes for today is not resulting in the right types of investments. This will ultimately increase customer costs in the long term. We think we need, as a matter of urgency, to consider how the capacity we procure and build from the next auctions meet with our longer-term decarbonisation objective and not just our short-term security of supply emergency. Based on our analysis and review, we think some small but targeted amendments should be considered before further large volumes of capacity are procured. In the meantime, in the March 2023 T-4 auction we believe that the minimum amount of new MWs should be procured to mitigate over investment in capacity that is not net-zero compatible. Thereafter targeted amendments determined in 2023, to help signal net-zero compatible existing and new generation, should in our view come into play. We believe that taking the approach of a) minimum new MWs being procured next March, together with b) determining targeted changes in 2023 to better signal low- and zero- carbon technologies will be in the interests of the customer in terms of cost but also the industry in terms of our reputation to deliver valuable investments.

2. Context and summary views

BGE's key ask in response to this consultation is that in 2023 the Regulatory Authorities (RAs) undertake a consultation and decision-making process on adjustments needed, within the current capacity market design, to ensure the optimum mix of technology appropriate for a high-renewables (RES) net-zero system starts materialising. BGE believes that the need to ensure new capacity procured is compatible with net-zero targets is becoming increasingly urgent as we move from one T-4 to the next long-term T-4 or T-3 auction.

Given the short timeframe from now until next March's T-4 CY2026/27 however, BGE accepts that the existing BNE approach and methodology is our only option to determine price and bidding caps for that auction. But our comments on the BNE inputs and assumptions here are purely to enable March 2023's T-4 to progress. Thereafter a root and branch review in 2023 of the appropriateness of the BNE methodology, and related issues for optimum incentivisation of decarbonisation compatible technology, is necessary in our view.

In general, the role for gas at least on a transitional basis to net-zero is widely recognised in industry reports but that gas needs to be signaled to be more efficient/ lower carbon compared to the types of units that are being signaled and that have cleared in recent auctions. Between MAREI's analysis demonstrating that the same level of gas capacity as is installed today (albeit running at ~80% of today's levels) is required in 2030, and CRU's desire to procure 2GW of new gas capacity by 2030, the enduring role for gas into the next two decades at least is unquestionable. However, if we are going to meet our CO2 reduction targets the efficiency of the use of gas must necessarily improve by 2030 and we believe now is the time to consider how this is ensured. Recent auctions indicate that the cheapest cost outcome is being pursued over low carbon options which will not ultimately bode well for consumers in the medium-long term.

To demonstrate the impetus behind our ask for a 2023 root and branch review, BGE has assessed the extent of carbon (CO2) savings that could occur were imminent focus put on ensuring the procurement of net-zero compatible capacity. We outline the scenario in section 3 below but in summary, taking the T-3 2024/25 auction outcome for example, if the OCGTs procured were all of high efficiency (versus low efficiency)[1] a potential 1.9 Mt CO2 savings over a ten-year contract would be achievable. This is significant in that our current carbon budget in electricity requires us to stay under 7 Mt C02/year to 2025 if targets are to be met and at present, we are at 10 Mt CO2/year. There is considerable merit therefore, in the context of carbon budgets and sectoral ceilings, for the RAs to introduce carbon focused adjustments to the capacity market in 2023. Whether this is possible via the current BNE approach, a new BNE approach or an alternative approach needs consultation and decision in 2023.

From an existing unit's perspective, the current BNE methodology is underperforming when it comes to providing signals to efficient existing units to: continue to invest to maintain them to high standards / invest to ensure enhanced reliability as RES increases/ implement retrofits and refurbishments. Jointly signalling the need for efficient new and existing units will result in the optimum cost outcomes for the consumer. And now this consultation is proposing to introduce an existing capacity price cap (ECPC) that would be well below the clearing price for exiting capacity in the last nine auctions that existing capacity cleared in. The signal for existing capacity is broken and needs urgent revision. It should form part of the wider review we propose at the outset of this response, in 2023. There are existing efficient units today and enabling continued investment in these units, via the right price signals, can help extend their life at a more optimum cost for the customer than brand new investment under long-term contracts.

The market needs to start signaling the 'optimum cost' as opposed to 'cheapest at the time' capacity with an eye on decarbonisation. BGE is not advocating for a change in market design to the current capacity remuneration mechanism (CRM) given that would i) take several years, and ii) introduce major regulatory uncertainty (when we already have major uncertainty in the other main revenue stream of system services), and iii) our EU state aid approval for the CRM stands until 2027. We do however believe that the overarching design of the current CRM, which incentivises the cheapest unit that exists today to be built regardless of efficiency and suitability for a net-zero system, is not conducive to net-zero targets. De-rating factors and run hour limits do not go far enough in helping to signal the mix of net-zero compatible capacity we need. As it stands, the cheapest outcome from the auction clearing is not necessarily the best outcome anymore as it purely takes into account the current environment with no look-forward element embedded in it. Looking forward, a decarbonisation lens must necessarily be adopted in that while a unit may be the cheapest to invest in today, come 10-15 years' time if the unit is not compatible with decarbonisation targets it may end up being stranded or need huge investment costs to keep it net-zero compatible which overall can lead to higher costs for consumers at that point or undermine security of supply if the unit ceases to operate. It would also undermine the value the consumer would have got from paying for the 10-year contract originally obtained by the unit. Hence it is the *optimal cost* from a decarbonisation perspective, as opposed to the *cheapest cost*, capacity that needs to start materialising in capacity auction outcomes as soon as possible. Ultimately, we need to start seeing investors make unit investment decisions that consider a trade-off between the flexibility and efficiency of a unit such that system stability/ services and adequacy can increasingly be achieved with the same unit.

Rather than altering the market design, **we believe that assessing alternatives to the BNE or alternative use of the BNE (e.g., choosing the optimum unit that balances flexibility with efficiency capabilities) coupled with consideration of CO2 parameters / efficiency levels for units bidding into the auction should form part of the 2023 considerations**. **State aid implications should not be a deterrent**. We note that the CRM state aid decision in 2017 from the EU Commission was made "*without prejudice to the future rules applicable to electricity market design*".[2] The EU Regulation on electricity markets (Regulation 2019/943) has since been adopted and allows limits on CO2 output from units procured via the capacity market. While the Regulation outlines certain timelines from when the CO2 limits are mandatory for inclusion in CRMs, it is

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[1] The higher a unit's efficiency, the more carbon friendly it is
[2] Footnote 27 of the Irish State Aid decision, 2017.
https://ec.europa.eu/competition/state_aid/cases/267880/267880_1948214_166_2.pdf

possible for Member States to adopt such CO2 limits prior to the limits becoming compulsory under legislation. For example, Italy incorporated these CO2 limits into their capacity market design before the Regulation became applicable and while the EU Commission had to review the already approved Italian CRM state aid decision, the review took less than 5 months. Thus, amendments to the CRM that are in line with the EU decarbonisation agenda including the Clean Energy Package (CEP) have considerable scope to be incorporated in our existing capacity mechanism within reasonable timeframes even if an updated EU opinion on our existing state aid approval is required.

In summary, BGE asks that the 2023 review of the appropriateness and utility of the current BNE methodology in light of decarbonisation targets, includes at least:

i. **Consideration of whether continuation of the current BNE methodology**, i.e., cheapest cost unit with no consideration of efficiency level/ low carbon compatibility, is suitable going forward when we need units being procured in 2023 and thereafter to be net-zero compatible during the lifetime of the units.
ii. **Consideration of what alternatives to using a BNE approach** to manage market power and set price/ bid caps are. For example, GB uses a levelized cost of capital approach which could help to give correct signals to efficient existing units seeking to remain reliable in a high-RES system. This could also be used as a way to cater for increased costs which units may need to pay to become hydrogen or CCS ready. Further alternatives to consider also include technology specific bidding approaches.
iii. **Consideration of further alternative ways to incorporate CO2 and efficiency requirements into future capacity procured** – for example consideration of a carbon price to be included in bids of certain/ all unit types or adoption of carbon emission limits outlined in the CEP before the CEP requires them to be mandatory. The European Commission's vehicle emissions standards[3] incentivises the uptake of zero- and low-emission vehicles by setting annual specific emission targets for each manufacturer is an example of how limits can be deployed successfully.[4] A carbon efficiency multiplier in bids is another option for consideration. Longer-term contracts for those units that are more efficient and thus more net-zero compatible (and likely more expensive) should also be included for consideration and we note that EY[5] recently suggested such longer contracts to start attracting the right combination of flexible, efficient capacity.

Consideration or decisions on such areas should not be dissuaded by the fact that the CRM state aid decision for SEM needs to be reviewed by the EU Commission given the Italian precedent for obtaining an updated decision on its state aid approval within 5 months as it was in line with the decarbonisation agenda.

In terms of continuation of the current BNE approach solely for next March's T-4 CY2026/27, BGE has outlined its summary position on the key assumptions that need to be altered in section 3.7 below. Our headline ask here however is that the volume of new MWs procured next March, is kept to the minimum level required only to mitigate the security of supply shortfalls EirGrid's GCS envisages. Otherwise, we risk procuring considerable MWs next March that are not sufficiently efficient to endure in a net-zero system. These units will have ~20-year lifespans bringing us to the mid-2040s which drives the need for them to have appropriate efficiency (i.e., be net zero carbon friendly). Other key elements that BGE urges the RAs to reconsider for the BNE approach being used next March include:

- **Revenues**: The need for the energy Inframarginal Rent (IMR) and DS3 revenues to be modelled to better reflect load factors and running profiles of thermal units in high-RES systems. Assuming IMR, DS3 earned in 2025/26 will remain the same to 2035/36 is an unacceptable assumption. DS3 earnings need to also reflect how certain DS3 products are settled based on market positions vs. physical dispatch.
- **Technology**: To progress some way towards better efficiency/ lower carbon units the OCGT reference technology should be smaller in size, ~50MW and the BESS technology should be of 4+ hours duration as that is more suitable from an adequacy (as opposed to pure flexibility) perspective.

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[3] For 2020, 2025, 2030 https://ec.europa.eu/clima/eu-action/transport-emissions/road-transport-reducing-co2-emissions-vehicles/co2-emissionperformance-standards-cars-and-vans_en
[4] The targets are based on the EU fleet-wide targets. Manufacturers of heavier cars are allowed higher average emissions than manufacturers of lighter cars. If the average CO_2 emissions of a manufacturer's fleet exceeds the target in a given year, the manufacturer has to pay an excess emissions premium per g/km of target exceedance.
[5] https://www.semcommittee.com/sites/semc/files/media-files/SEM-22-054A%20Performance%20of%20the%20SEM%20CRM.pdf

- **Costs**: the site procurement cost approach falls short of what is expected – assuming a 100% mark up on agricultural land does not take account of the requirement for these sites to be located near demand centres and mostly in already industrialised zones where the relevant permits etc are already in place which drives up site costs.
- **Inflation and WACC**: We also seek more realistic assumptions for inflation to be applied across the revenues and costs piece. Please see EAI's response on the matter and on WACC – BGE was a participant in the Frontier report procured on behalf of EAI and fully supports the messages and proposals therein.

The remainder of our response goes into the above points in extra detail.

3. Current BNE approach: for T-4 CY2026/27 (auction date March 2023) application only

As outlined in our introduction above BGE believes that it is critical that capacity which is procured before the mid 2020's, and ideally from next March, is net-zero compatible. Our view is that the current BNE will not help ensure that the appropriate mix of technology required for the 2040s and beyond materialises. We do however recognise that the next T-4 is less than 4 months' away and must necessarily procure MWs given the security of supply crunch SEM is experiencing. With this in mind, we accept the use of the current BNE approach for only one more auction and have outlined below our view on the shortcomings of the assumptions in the CEPA/ Ramboll report such that several of the proposed BNE values are underestimated. Our proposals below in this section on the BNE are only relevant to the T-4 CY2026/27 (March 2023) capacity auction. We urge the RAs to undertake a root and branch review of the BNE over the course of 2023 to facilitate the incentivisation of an appropriate technology mix via the current mechanism to apply from the next T-4 after March 2023.

3.1 Choice of technology

The proposed technology options outlined in the consultation should only be considered as options for the next T-4 CY2026/27 auction next March. Over the course of 2023 a BNE or non-BNE approach to determining price signals for investment in new and existing capacity suitable for the future high-RES system and that account for wider policy issues, in particular decarbonisation, needs industry consultation.

CCGTs

While not ideal in terms of a balance between flexibility and efficiency, we accept that the 450MW - 500MW CCGT (F Class) should be included as a reference technology for the upcoming T-4 CY2026/27 auction. The technology type is in line with the ACER methodology as:

i. Its reliable and generic cost information is available to future investors;
ii. the costs of building and operating the same type of CCGT unit are similar across units;
iii. per table 3, 4 provided in the CEPA/Ramboll study, CCGT technologies of a similar size and type are well established in Ireland; and
iv. their development is not significantly bound by technical constraints or restricted by national or EU regulatory frameworks.

The dual fuel CCGT and OCGT technology types are also accepted as they are reflective of the requirements of the Secondary Fuel Obligation in Ireland and Fuel Switching Agreements in Northern Ireland. We also agree with CEPA's view that the typical generation capacity (500MW+) of a CCGT H/J class would be too high a capacity for the SEM market considering the likely operational regime in a high-RES system and that such a unit could become the largest single infeed ("LSI"), given the current LSI is 500MW.[6] To procure a H/J class CCGT unit for delivery in 2026/27 would be too risky as an unplanned outage could put huge strain on other generation and the system to meet demand.

OCGTs

BGE agrees with the inclusion of an OCGT as a reference technology option that provides flexibility to meet peak demand and supports a high-RES system by providing important capacity at times of system stress when

[6] The current 500MW LSI accounts for the situation where one of the two HVDC interconnectors is importing at full capacity

variable renewable generation is low and interconnector flows are limited. We disagree however with the reference technology manufacturer and proposed size. We note that this capability is limited to short-term response. We are concerned with the choice of SGT5-2000E to represent the open cycle plant as this type of OCGT has the worst in class efficiency and anomalously low capital costs in comparison to its competitors, as shown in figure 3.2 of the CEPA/Ramboll. We believe that the system would better benefit from the addition of more but smaller OCGT units. For example, 4 OCGT units with a capacity of 50MW each which could be spread over a wider area to simultaneously provide local system services (as well as capacity adequacy) to 4 different areas, decreasing the single points of failure risk and operational strain on the transmission network. Our view is that larger single OCGT units are:

i. slower start and therefore slower to respond to system requirements,
ii. generally less flexible than smaller units; and
iii. have larger points of failure compared to smaller units i.e., the impact of an unplanned outage for a 200MW OCGT unit is greater than the impact of an unplanned outage on, for example, one of four 50MW OCGT units.

OCGT units with capacity greater than 100MW would also result in poor distribution of synchronous resources throughout the system. Therefore, the proposed 200MW OCGT is too large relative to the SEM and is unsuitable for a wind-dominated Irish system as it will not provide the level of flexibility required. This preference is evident in recent market trends that show increased investment in smaller and less-carbon intensive OCGTs.

Reciprocating engines

The flexibility, high ramp rate and short start times of reciprocating engines make them suitable for meeting peak demand. They are also more capable of supporting a high-RES system by providing important capacity at times of system stress when variable renewable generation is low and interconnector flows are limited. We also note the two candidate engines put forward in the study and we are of the view that the MAN Energy 51/60 DF model should be put forward as the reference technology type for reciprocating engines as it is more reflective of the type of unit to be chosen in current market conditions.

BESS

BGE questions the appropriateness of a 2-hour BESS as a suitable technology option and believes that from a security of supply/ adequacy perspective the 100MW/200MW BESS reference technology should be of a duration of 4 hours+. Otherwise, given the limits of 2 hours duration when once discharged they are not available again until it charges, they should be considered more akin to a system support tool rather than an adequacy tool. In the longer-term, issues that merit more consideration for 4 hours+ BESS include:

- the appropriate volume to procure for our highly constrained system considering SNSP objectives, to mitigate market saturation and stranding of assets
- adjustment of de-rating factors to ensure incentives are appropriate and to reflect the adequacy provided by longer duration batteries during periods of low variable generation
- EirGrid's ability to optimise battery operations i.e., discharging and charging
- Information asymmetry on when batteries can/ should bid into markets is another issue that must be addressed.

While the above issues must necessarily be addressed to help get larger, system-adequate and suitable batteries off the ground, we still believe that the BESS option should be retained as a BNE option. We outline below how uncertain revenues are for BESS but it is clear that BESS is low-carbon technology that is needed to meet the peak demand deficits we currently experience.

3.2 Site procurement costs

We consider agricultural land values alone are not a suitable proxy in the calculation of site procurement costs and that these costs have been grossly underestimated. Similar to the 2018 Poyry BNE study and the previous 2016 CEPA BNE study, CEPA continues to assume that future generation units will be built on agricultural land, although we note the uplift applied in the 2022 CEPA BNE study to reflect that generation may be built on an industrial site. BGE is concerned that even with this uplift, the per acre cost of a site in the consultation proposal has decreased significantly from the 2016 CEPA BNE study and the 2018 CEPA BNE study (€150K in ROI and

€187.5 in NI) to the 2022 CEPA BNE study (€35.9K in ROI and €40.5K in NI). The large decrease in estimated land costs is particularly unusual and concerning given the current high land price inflation.[7]

We note CEPA's expectation is that industrial land is likely to cost more than agricultural land, however we believe that this arbitrary 100% mark-up is not sufficient to cover the value of industrial land compared to agricultural land. Furthermore, plants are increasingly strategically located near demand in industrial zoned areas where the value per acre is far higher and as CEPA stated in their 2016 report, *"any affected landowner is likely to view a power station as industrial development (whether or not they had any likelihood of securing consent for such a use) and/or are likely to argue for injurious affection (diminution in value of land held with land taken)".*[8]

BGE asks that the methodology for calculating site procurement costs for the upcoming T-4 CY2026/27 auction is consistent with previous studies undertaken by Poyry and CEPA and continues to reflect the per acre cost of industrial land by adjusting it for inflation to reflect 2022 land prices.

3.3 Annual gas entry and exit capacity

The assumption that the optimal trading strategy for a CCGT is to hedge 65% of its peak gas transportation capacity appears reasonable considering that as renewables increase, this plant are expected to run less. It also appears reasonable to assume that OCGT and reciprocating engines in Ireland would provide peaking capacity and procure daily products, therefore their fixed costs for the purpose of Gross CoNE are zero. We believe that it is also reasonable to expect OCGT and reciprocating engines to procure exit capacity to cover 15% of the unit's rated capacity to reflect that there is no daily product for exit capacity in Northern Ireland.

3.4 Inflation

The proposed capital costs are in our view materially underestimated. EPC costs need to be adjusted for relevant cost changes from the reference date of February 2022 to September 2022 (the end of the capacity year)[9] and to reflect more recent data that has been published since CEPA/Ramboll undertook their study. The Frontier report shows that this would result in an additional uplift above CEPA's estimate of 11%[10]. This uplift would better reflect that construction costs have been running ahead of general inflation in recent years, and further upwards pressure on costs is expected in the coming years.

As outlined in the Frontier report, evidence from past auctions shows that the proposed new price cap is significantly below the price that new entry has previously required to invest. Current inflationary pressure coupled with the proposed lower price cap will compound the risk of under-procurement in the T-4 CY2026/27 auction.

3.5 Revenues

3.5.1 IMR

We disagree with the assumption that IMR revenues are maintained at the same level per technology across the 2026/27 to 2035/36 period. This assumption is unrealistic and overestimates the ability of thermal units to maintain IMR in the context of increasing levels of variable RES generation that will also deliver adequacy during long low-RES periods. Increasing levels of RES generation will mean that gas generators will operate with more ramping events and longer hours at minimum generation.

BGE believes that some form of reduction to the CCGT infra-marginal rent figures to reflect lower rents in the later years is required, similar to the indicative example of the impact of lower revenues over a 10-year period

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[7] For example, the Irish Farmers Journal estimated that between 2020 and 2021, agricultural land prices increased by 16% in ROI and 14% in NI.

[8] SEM-15-32a CEPA Cost of BNE 2016 report.pdf (semcommittee.com) section 4.3.2

[9] Note that these costs are then inflated to 2026/27 as part of the final Net CONE calculation, discussed further below.

[10] CEPA/Ramboll uplifted the original EPC estimate using inflation from February to June 2022 (8.4%), but the same source shows prices increased from February to September by 20.7%. This translates into an 11% increase over CEPA's estimate. This translates into an increased EPC cost estimate of approximately €36m for CCGT plants and €9m for OCGT plants in both Ireland and Northern Ireland.

provided in the CEPA study. This approach is more plausible as it more accurately reflects a high-RES world where conventional plan run less and cycle more.

Given the TSOs' difficulties in optimising battery operations and the ability of the system to cater for them especially given high constraints and increasing SNSP, an assumption around this and its effect on IMR should be incorporated for the BESS also.

3.5.2 Administrative Scarcity Pricing (ASP)

We do not agree that the SEMC should continue to apply an uplift to IMR of "around €4-6/kW/year for the impact of Administrative Scarcity Pricing (ASP) for CCGTs and OCGTs" as we expect that the uplift would be incorrectly applied on top of modelling runs resulting in the likelihood for scarcity pricing being double counted. This is because the model runs would have already internalized the likelihood of ASP revenue occurring through the analysis of simulated, hourly day-ahead electricity price from the SEM PLEXOS model. We also note that CEPA do not account for this in their study and we believe it is wrong for SEMC to arbitrarily include it given the SEMC's position in the EY Review of the CRM that Administrative Scarcity Pricing is not being seen in the SEM. [11] Furthermore, CEPA replied to the BNE QA that "*the uplift existed in the Poyry 2018 study because the analysis involved a deterministic assumption that there would be 8 hours of Full Administrative Scarcity Pricing (ASP) and a further 4 hours of 'Partial ASP'. This assumption is not relevant to the 2022 analysis because IMR is based on wholesale market modelling which provides hourly generation and day-ahead prices and allows for IMR to be calculated on an hourly basis*." We therefore ask for its removal given the lack of justification for its inclusion.

3.5.3 DS3

BGE believes that the DS3 revenues for the units are overestimated and that the 20% reduction on prices when we move from regulated tariffs to auctions has no sound basis. CEPA/Ramboll recognise that *"this is an uncertain assumption"* and point to a lack of evidence to determine the appropriate size of this discount. The 20% reduction is also inconsistent with investor expectations given current policy direction, for example, EirGrid/SONI are currently consulting on a number of options relating to reductions to DS3 tariffs[12].

The MaREI report states that "*In 2030, batteries, interconnectors and DSM will dominate the provision of reserve in operating reserve categories such as Fast Frequency Response (FFR), Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve 1 & 2 (TOR1 and TOR2)."* Coupled with the addition of the Celtic Interconnector, this means that there will be less scope for, in particular thermal, units to earn DS3 revenues even when they are running as the system services market will be more competitive. This is noted in the MaREI report[13] which states that "*it is inevitable that opportunities for conventional generation to gain income regularly from some system services will diminish with the reduction in run hours*".[14] We would urge caution though in assuming major DS3 earnings for BESS either at this stage given the challenges outlined for BESS technologies above and the uncertainty of the future arrangements for system services (FASS) design.

BGE would like to clarify that DS3 and IMR revenues are complementary and must not be treated as, or assumed to be, substitutes in the approach to calculating BNE. We believe that this assumption is incorrectly reflected in the consultation[15]. There are several products for example FFR-TOR2, the replacement reserves and inertia that require synchronous and battery units to have a Final Physical Notification (FPN) i.e., an ex-ante energy position, before it is paid. So, if a unit has no ex-ante energy position its IMR reduces as well as its DS3 revenue for these products for example. With ramping for example, which is paid on physical dispatch, when ramping services (RM1, RM3) are needed during high wind, these cannot be provided if the unit is not running or capable of responding within the 1 or 3 hours and therefore there can be no revenue transfer from IMR to DS3 if the unit is not running and not flexible to 1 or 3 hours start up. We therefore ask that the running

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[11] SEM-22-054 Call for Comments on EY Review of the Performance of the SEM Capacity Remuneration Mechanism | SEM Committee

[12] DS3-System-Services-Consultation-16-Sept-2022.pdf (eirgridgroup.com)

[13] Our-Zero-e-Mission-Future-Report.pdf (eaireland.com)

[14] Our-Zero-e-Mission-Future-Report.pdf (eaireland.com) page 40

[15] As stated in CEPA/Ramboll's BNE Study, with regards to DS3 revenues (page 34): *"there is scope for these revenues to reduce over time if thermal units are required to run less often. However, this effect is at least partially offset by the potential for system services to be more valuable in the future. Also, some services can be provided without the unit already being synchronised with the grid."*

assumptions applicable to IMR are reflected in the assumptions for DS3 and that recognition of the correlation between market positions and physical positions depending on the product is applied for revenue-earning assumptions.

The modelling for IMR and DS3 revenues was undertaken in early 2022 for the 2025/26 capacity year. Given the uncertainty surrounding future IMR and DS3 revenues, it is inappropriate that these revenues were only modelled based on a single capacity year and that the extrapolation of these revenues (which also accounts for inflation) is not a suitable alternative to proper Plexos modelling. We note CEPA/Ramboll's understanding in the Q&A that followed this consultation paper that the RAs are considering undertaking more and specific PLEXOS runs for the purpose of the final version of the report[16].

3.6 WACC

We are concerned with the lower WACC proposed in this CEPA/Ramboll's study relative to Poyry's 2018 study, given the current high interest rate environment compared to 2018. We would expect that, given the current market evidence, the nominal cost of capital in 2022 would be higher than 2018 for most investors. It is important the final decision reflects how significantly the economic environment has changed in recent months.[17] We have supported the Frontier report on the CEPA/Ramboll BNE study and ask the RAs to consider this report alongside our response. We support Frontier's findings and in particular we ask that the WACC is revised and updated to include the following:

- The current environment of higher investor uncertainty and interest rates
- The current market evidence that results in a more accurate estimate of the risk-free rate and cost of debt (due to CEPA/Ramboll's July data cut-off)
- A justified asset beta estimate that is consistent with GB regulatory precedent and reflects the different risks faced by different technologies and the risks faced by a new entrant

These revisions are critical as the current underestimation of WACC will result in a net CONE that would be insufficient to cover an investors' costs.

3.7 Conclusion on potential changes to the current BNE approach for T-4 CY 2026/27 March 2023

In conclusion, in sections 1 and 2 above BGE has proposed that the BNE in its current format is retained only for the next T-4 and that a root and branch review of the BNE/ non-BNE approach that will work best to deliver price signals that incentivise new and existing net-zero capacity occurs in 2023. However, given the time constraint of just 4 months to the next auction, BGE suggests the following amendments to the BNE to be used for next March:

i. **Technology**: A smaller OCGT and longer duration BESS should be references for these technologies – see section 3.1 above
ii. **Site procurement**: the agricultural land-based price augmented by 100% is wholly unacceptable and more realistic assumptions such as the need for land to be near demand centres and often in industrialised zones, needs to be incorporated – see section 3.2 above
iii. **Annual gas entry and exit capacity**: the assumption that the optimal trading strategy for a CCGT is to hedge 65% of its peak gas transportation capacity appears reasonable considering that as renewables increase, these plant are expected to run less.
iv. **Revenues**: the IMR assumptions must reflect the lower run hours of units as RES grows which will inevitably reduce IMR assumed earnings – for the CCGT the riskiness and range of potential earnings is broad and the BNE should err on the side of caution towards 106.48€/de-rated kW for IMR. Similarly running hour impacts on DS3 earnings needs to be better reflected for technologies assessed and the difference in settlement as between products like FFR and POR (higher of FPN volumes or physical dispatch if dispatched away from FPN) vs. ramping needs considerable recognition to ensure reasonable assumptions are applied. The 20% reduction is too arbitrary, inconsistent with investor expectations given current policy direction and is not supported by sufficient evidence. Finally, CEPA has provided considerable rationale for why an assumption around €4-6/kW/year for ASP should be excluded and we urge the RAs to take this on board and exclude the ASP adder too. See section 3.5.
v. WACC: We ask for the WACC to be revised and updated to include the following:

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[16] [Best New Entrant Study 2022 – Q&A (semcommittee.com)]
[17] Inflation is currently at record levels, with prices in Ireland estimated to have risen by 9.5% in the year to October 2022[17] and CPI increasing by 11.1% in the UK over the same period.[17]

- Current environment of higher investor uncertainty and interest rates
- Current market evidence that results in a more accurate estimate of the risk-free rate and cost of debt (due to CEPA/Ramboll's July data cut-off)
- A justified asset beta estimate that is consistent with GB regulatory precedent and reflects the different risks faced by different technologies and the risks faced by a new entrant

While we have concerns around the net-zero compatibility of units being procured next March, we realise the auction must nevertheless be held. However, to mitigate the risk of "locking in" large MW volumes (with 20year lifespans and so they will exist into the 2040s), BGE suggests that consideration is given to procuring a volume of additional (new) capacity only required to mitigate security of supply risks.

4. Incentivising the appropriate mix: validity of the current BNE approach for a net zero system?

The current methodology is not delivering signals for new or efficient existing capacity

The current BNE approach in our view will not deliver a mix of technology compatible with a high-RES system and our net-zero ambitions. The capacity procured in the T-4 CY2026/27 auction will be delivered from October 2026 and will have approximately a 20-year life span which will see them exist until 2046, only 4 years short of our 2050 net-zero targets. It is therefore critical that any investments procured after this auction are compatible with our net-zero targets insofar as possible. Capacity market signals provided after the T-4 CY2026/27 auction must account for our carbon budgets[18] and carbon emission targets including sectoral ceilings and any other relevant and legally binding emissions standard.[19] This will enable an appropriate mix of capacity adequacy to be achieved from both a security of supply and decarbonisation perspective, [20] at optimum costs for consumers.

It is clear that the current BNE approach is also failing to signal investment in emissions reduction and improved efficiency for existing units. It is critical that existing units are i) incentivised to be upgraded to high-standards which are compatible with a high-RES system ii) ensured a return on this investment that a rational investor would seek to make and iii) incentivised to extend their asset life to secure cost-savings for the consumer compared to investment only in brand new capacity. It is time to start considering the prospect of investors needing to invest in both efficient new and efficient existing units that achieve a trade-off/ balance as between efficiency and flexibility to replace base load plant that is expected to retire (e.g., Moneypoint) with generation that can provide the exact system services and adequacy required for the future system. The future approach should not solely focus on new investments but ensure that it provides signals for efficient existing units to: continue to invest to maintain them to high standards and / invest to ensure enhanced reliability as RES increases / implement retrofits and refurbishments.

Trajectory of current procurement approach and parameters and carbon impact concerns

As referenced in our introduction, we believe that if we continue the current trajectory in terms of capacity procured that we are at risk of locking in huge volumes of inefficient MWs that although suitable for a 2020s system will not stand the test of time when it comes to carbon compliance and net-zero targets. From our internal analysis, we have taken the T-3 CY2024/25 capacity market auction as an example and looked at two scenarios:[21]

a. Where all the OCGTs cleared are assumed to be high efficiency units (2,000MWs at 41.5% efficiency), versus

b. Where all the OCGTs cleared are assumed to be low efficiency units (2,000MWs at 36.5% efficiency).

[18] Ireland has two carbon budgets that ensure that it meets a 51% GHG emissions reduction target by 2030. The first two carbon budgets cover the periods 2021 – 2025 and 2026 – 2030 and seek to ensure that Ireland meets the 51% GHG emissions reduction target by 2030 as legislated for in the Climate Action And Low Carbon Development Act 2021.The first carbon budget was approved by the Oireachtas in 2022 and requires Ireland to remain within a total GHG emissions upper limit of 295 Mt CO2eq in the period 2021-2025.

[19] Such as the Paris Agreement

[20] Ireland's National Policy Position on Climate Action and Low Carbon Development has set a target of an aggregate reduction in carbon dioxide (CO_2) emissions of at least 80% (compared to 1990 levels) by 2050

[21] For simplicity, in both scenarios, it is assumed that in both cases the 2000 MW all averages out to running 1500hrs annually across the 10 years. (It is likely that annual running of the actually cleared T-3 units will exceed 1500 hours in several years in the future).

Our results show that the difference in carbon dioxide emissions over the 10 years (from fuel burning alone) is 1.87 million tons of CO2 equivalent. The difference over the lifetime of these assets will be higher still. This is significant as recent estimates from MaREI for the two-year period 2021-2022 suggest that by the end of 2022, Ireland will have emitted nearly half (47%) of the carbon budget with only three years left to stay within the target[22]. For electricity, the average annual emissions need to be less than 7 Mt over the next three years, and our annual average over the past two years is more than 10 Mt. A saving of almost 2 MT CO2 in a year is therefore of significant impact. There is considerable merit therefore, in the context of carbon budgets and sectoral ceilings, for the RAs to introduce carbon focused adjustments to the capacity market in 2023. Whether this is possible via the current BNE approach, a new BNE approach or an alternative approach needs consultation and decision in 2023.

The required outcome may not be the cheapest outcome at the time any more as costs to make units compliant with decarbonisation in 10/15 years can undermine any "value" perceivable from cheaper auction outcomes today. It is the "optimal cost" outcome taking account of future decarbonisation needs as opposed to "cheapest only" cost outcome that the SEM needs. The approach needs to cater for new units and the need for existing efficient units to upgrade or replant where appropriate.

Signals must start incentivising a balance between flexibility and efficiency in investor decisions

The mix of technology has important implications for our carbon budgets and procurement of this mix must take a holistic and system-led approach to the trade-off between the efficiency and the flexibility of the capacity market fleet. It is critical that we move from the current unit-based approach which incentivises investment in low-cost efficient plant that provides system adequacy to a system-led approach that incentivises investment in higher-cost flexible plant that provides support for a high-RES system such as a flexible CCGT. Given the regular cycling of a CCGT, this has the unavoidable consequence that the flexible CCGT will not achieve the highest possible efficiency for a base load CCGT but a significantly higher efficiency than the mid-merit and peaking plant that would have to run instead of the flexible CCGT. The decision on the trade-off between flexibility and efficiency, provided parameters on both are clear in advance, should sit with the investor in terms of the suitable technology to invest in that is net-zero compatible.

Optimal CCGT and OCGTs exist and so the future 'new' thermal capacity procured should include for example design features that:

- For CCGTs: enable regular cycling, have fast start up times allowing response even when not online, low minimum on times, strong system service capabilities, scope for open cycle operation, be hydrogen or CCS compatible/ ready
- For OCGTs: a minimum efficiency requirement of the order of 40%, for smaller units (<50 MW), Hydrogen ready/CCS compatible design to help lower net-emissions, ability to work as closed cycle.

In the future approach, existing CCGT and OCGT should also be incentivised to invest in achieving the above optimal specifications to increase the carbon efficiency of the existing fleet. This joint signaling (to new and existing units) should lessen the dependency of our carbon targets on investment in solely new capacity and result in the optimum cost outcomes for the consumer.

State aid approval amendments can take account of C02 limits quickly so should not deter CRM updates

As part of the future looking piece and consultation we propose in 2023, we recognise there may be a concern that state aid approval implications may arise. We note however that the Irish capacity market state aid decision in 2017 determined the decision "without prejudice" to the - at the time - draft regulation on the electricity market. Article 22 of the Electricity Regulation[23] provides for certain C02 limits to be included in capacity mechanisms. Italy in July 2019 obtained Commission approval to adjust its capacity market state aid approval to incorporate these CO2 limits even though the requirements were not at the time compulsory.[24] It only took Italy less than 5 months to get the approval passed by the Commission. Consideration or decisions on how to adjust the CRM to be more net-zero compatible should not be dissuaded by the fact that the CRM state aid decision for SEM

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[22] How much of Carbon Budget 1 (2021-2025) has already been emitted and remains? - MaREI
[23] Design Principles for Capacity Mechanisms, Regulation 2019/943 of the European Parliament and of the Council
[24] State aid: modification of Italian capacity mechanism (europa.eu)

needs to be reviewed by the EU Commission given the Italian precedent for obtaining an updated decision on its state aid approval within 5 months as it was in line with the decarbonisation agenda.

2023 considerations

Among the issues to consult on in 2023, we suggest:

- The RAs should consider the introduction of a carbon cost that incentivises system-wide investment in efficiency and low-carbon plant. Increased efficiency means lower carbon which will drive lower costs and will therefore make high efficiency plant competitive in setting marginal cost. This differentiation could be achieved using a carbon constraint, similar to the locational constraint currently in place, whereby a carbon efficiency multiplier in auction bids would benefit less carbon intensive technologies.[25]
- It might be possible for a higher carbon unit to meet a low annual emission limit if its running was limited to periods of high electricity demand or stress events to ensure security of supply while also supporting the decarbonisation goals. An emissions limit could be ramped down over time by excluding no technology in the short term but then gradually forcing out high carbon technologies in line with our emissions reduction targets. The approach would provide for orderly exit of high carbon generation and a long-term signal for investment in zero emissions dispatchable technologies and allows existing capacity units time to schedule new investments and/or refurbishments (e.g., converting CCGT to hydrogen)[26]. The European Commission vehicle emissions standards for 2020, 2025 and 2030 which incentivise the uptake of zero- and low-emission vehicles provides a good precedent in Ireland for this approach.[27]
- Long multi-year agreements may contribute to supporting the investment case for low carbon technology, particularly where more innovative new build technologies are concerned (i.e., CCGTs, long duration storage) to ensure security of supply in a net-zero context. This proposal was put forward as a potential remedy in the EY Review of the Performance of the CRM[28]. Eligibility for longer contracts could be determined using a CO2 emissions limit and could account for 'lower' rather than 'low' carbon capacity to achieve the optimal mix.
- In GB to reflect the need to procure a technology mix compatible with our net zero targets they link the capex thresholds to the capital costs of building a low-carbon unit or decarbonising an existing unit. This levelised cost of capital approach links contract duration with capital expenditure by calculating the ratio of the total "cradle to grave" costs of a generic plant to the total amount of electricity expected to be generated over the plant's lifetime. The approach reflects that capital-intensive units may experience difficulty in accessing finance making them uncompetitive in the auctions and provides different levels of capital cost for different technologies which results in a better market signal for investment, while maintaining oversight through an ex-post review of a bid if the RAs believe the LCOC has been unjustifiably exceeded for that bid.

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[25] This could be defined on the basis of a capacity's carbon intensity (kgCO2/MWh) or total annual emissions (kgCO2 per annum).

[27] https://ec.europa.eu/clima/eu-action/transport-emissions/road-transport-reducing-co2-emissions-vehicles/co2-emissionperformance-standards-cars-and-vans_en The vehicle emissions standards aim to contribute to the achievement of the EU's commitments under the Paris Agreement, reduce fuel consumption costs for consumers and strengthen the competitiveness of EU automotive industry and stimulate employment. The EU fleet-wide CO_2 emission targets are 95 g CO_2/km for cars and 147 g CO_2/km. Specific emission targets are set annually for each manufacturer and are based on the EU fleet-wide targets, taking into account the average mass of the manufacturer's new vehicles registered in a given year. This means that manufacturers of heavier cars are allowed higher average emissions than manufacturers of lighter cars. If the average CO_2 emissions of a manufacturer's fleet exceed its specific emission target in a given year, the manufacturer has to pay – for each of its vehicles newly registered in that year – an excess emissions premium of €95 per g/km of target exceedance.

[28] SEM-22-054A Performance of the SEM CRM.pdf (semcommittee.com)

I hope you find the above comments and suggestions helpful. We ask the RAs to, in particular, consider our overview and asks in section 2 above, summary asks in section 3.7 and suggestions for what the proposed 2023 review should cover from our last sub section immediately above.

Please do not hesitate to contact me should you wish to discuss further.

Yours sincerely,

Niamh Trant
Regulatory Affairs – Commercial
Bord Gáis Energy

{By email}