Best New Entrant Study 2022 – Q&A

Single Electricity Market (SEM) Committee

24 November 2022

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1. INTRODUCTION

Cambridge Economic Policy Associates (CEPA) and Ramboll were commissioned by the Commission for Regulation of Utilities (CRU) and Northern Ireland Utility Regulator (UR) (collectively, the Regulatory Authorities (RAs)) to produce a report to estimate the Cost of New Entry (CoNE) for the Single Electricity Market (SEM) Committee.

On 19 October 2021, the SEM Committee published our report alongside a consultation paper on the Best New Entrant (BNE) Net CoNE.[1] To assist stakeholders in responding to this consultation, the RAs have offered stakeholders the opportunity to submit clarifying questions on the CEPA/Ramboll report. This document contains the questions received and our responses to them.

[1] https://www.semcommittee.com/news-centre/best-new-entrant-consultation

2. Q&A

Question	Response
Please can you explain precisely where the WACC is impacting the Net CONE calculations? Has the WACC in the report been used to discount any of the recurring costs and revenues, as well as the up-front capital costs?	The WACC is being used in two places. The first is the conversion of the up-front capital costs into an annual equivalent. The second is the conversion of Net CoNE from 26/27 values into a level nominal (and level real) equivalent value in the final section of our report.
Why has CEPA decided to use 10-Year German bond yields for the risk-free rate in the Republic of Ireland rather than the equivalent Irish bonds?	Our analysis for the Republic of Ireland cost of capital uses Eurozone market evidence. The logic for this is set out in the 'Regional Focus' text in section 6.1 of our report. From a theoretical perspective, in a monetary union such as the Eurozone, individual countries would be expected to converge onto some central view over a long enough time period ('long-term equilibrium'). From a practitioner's perspective, we suggest investors would typically view Irish utility investment as part of an asset class that includes European utilities more generally; and From a pragmatic perspective, Eurozone data provides a larger and richer information source than the more limited Ireland-only data, meaning our estimates are more likely to be statistically robust.
Please can you provide further details on how the uniform discount figure of 20% on 2021/22 tariffs was calculated for system services revenues?	The analysis which unpins the 20% discount is fully contained within section 7.2 of our report. The 20% is an assumption based on the qualitative factors identified.
Please can you explain why it was not possible to commission specific model runs for IMR revenues? Please can you provide more details on the 2025/26 capacity year runs that were used?	This analysis was constrained by the time and resources available prior to the consultation. We understand that the RAs are considering undertaking more and specific PLEXOS runs for the purpose of the final version of the report. The model runs were undertaken for the 2025/26 capacity year primarily for the purpose of assessing applications for Unit Specific Price Caps (USPC) in the 2025/26 T-4 capacity auction. The modelling was undertaken in early 2022 (prior to Russia's invasion of Ukraine) using the available, validated SEM PLEXOS model,[2] with updates to gas and carbon prices inputs.

[2] https://www.semcommittee.com/publications/sem-21-086-sem-plexos-model-validation-2021-2029-and-backcast-report

Question	Response
Please can you explain how your assumptions, including your choice of model for the reference technology, and assumptions regarding revenues, are aligned with statutory emissions targets in Ireland?	Our process for choosing reference technologies is set out in Chapter 3 of our report. This included the assessment of technologies against the ACER requirement that a reference technology shall have the potential for new entry. The consistency of the technology with national and European regulatory frameworks was considered at this stage. The statutory emissions targets are captured implicitly in our revenue analysis through the electricity market modelling (undertaken by the UR for assessing USPC applications) which informed our IMR assumptions. The market modelling includes assumptions from the 2021 Generation Capacity Statement. The 2021 GCS incorporated the Climate Action Plan 2019 but pre-dated the Climate Action Plan 2021. Our methodology for system services revenues uses the same run hour assumptions as for the IMR analysis, implicitly capturing the climate policies incorporated in the 2021 GCS.
Has CEPA considered additional costs of converting thermal units to hydrogen over their economic life? If not, can you explain why not?	During the technology selection process, we considered the issue of hydrogen readiness and found that turbine manufacturers tend to identify tolerance for hydrogen mixes with 60-70% hydrogen content by volume, with ambition to reach 100% hydrogen firing in the coming years. Concepts of hydrogen readiness tend to involve higher specification pipes and auxiliary systems (e.g., ventilation, fire protection) and siting designs customised to the method of hydrogen supply (e.g., on-site electrolysis or dedicated hydrogen pipelines). We have not reflected these elements in our reference technologies because the costs are too uncertain. An associated uncertainty is the composition of a future hydrogen supply chain in the SEM and the pace at which this will develop to support power generation at scale.
What inflation assumption is used for 22/23? What inflation assumptions are used for 2023-27?	As set out in Section 8.1.2 of our report, we have used a 2.0% long-term inflation expectation for both jurisdictions. This was consistent with previous BNE studies. In the report we recognised that inflation expectations were elevated relative to this long-term trend and that this will be reflected within nominal WACC parameters.
Will these inflation assumptions be updated for market evidence?	We do not currently intend to move away from the use of a long-term inflation assumption for our modelling but may consider doing so subject to consultation responses.
What month of data was used to calculate the risk-free rate and cost of debt?	Page 39 of the CEPA/ Ramboll report discusses how we have used a cut-off date of 31st July 2022 for our cost of capital analysis. On the risk-free rate and cost of debt,

Question	Response
	we stated our use of a 1-month trailing average to best reflect current market conditions.
Can you please set out the method and assumptions for calculating the IMR? Including: • What is the relevant price used when calculating IMR? Does this differ by technology?	The relevant price was the simulated, hourly day-ahead electricity price from the SEM PLEXOS model following a standard methodology used to assess USPC applications. The relevant price does not vary by technology.
• How is the impact of energy storage taken account of in the IMR calculation over the 20-year expected lifetime of the analysis?	The validated SEM PLEXOS model includes energy storage units which we understand reflect the 2021 GSC. The characteristics of these units are available in the documentation for the 2021 validated SEM PLEXOS model. The energy storage units in the model were not sufficiently similar to the energy storage BNE candidate we were considering, so we used a different methodology for energy storage (detailed in Section 7.1 of our report). We applied the method to the 2025/26 capacity year model output and assumed that the resulting IMR would remain constant over time.
• What is the assumptions and estimated IMR for 2035/36?	Section 7.1 on our report explains that for the infra-marginal rent (IMR) assumption, we were provided with the results of wholesale market modelling undertaken by the RAs for the 2025/26 capacity year. We assumed for the purpose of providing estimates of Net CoNE that these revenues are maintained across the 2026/27 to 2035/36 period. However, we also provided an indicative example of what the average IMR could be for a CCGT unit if IMR was to decline to zero after 10 years.
• What were the gas and carbon prices assumptions used in the calculation? From what time period were these assumptions for?	Page 10 of the SEM Committee's consultation paper notes that the modelling was undertaken using fuel curves from early 2022, before Russia's invasion of Ukraine. The same applies to the carbon price assumptions.
• We understand that the IMR calculation is based on 2025/26. What was the assumed RES penetration in this model run?	We have not analysed RES penetration because we were not responsible for the PLEXOS model runs. However, we understand that it is possible to calculate this from the publicly available, validated SEM PLEXOS model.
• What is the assumed position of each asset in the merit order? How does this evolve over the period modelled?	The position of each unit in the merit order is a function of the fuel costs, heat rates and fuel transport costs used in the validated SEM PLEXOS model, updated using fuel and carbon price assumptions available in early 2022. We understand that the fuel costs involved a quarterly profile which in theory could lead to changes in the merit order over the modelled period (2025/26), but considering the technology

Question	Response
	mix present in the modelling it is unlikely that there would have been any change in practice.
• What plant is the marginal price setter in each year?	There is no single price setter as the marginal unit can vary from one hour to the next across the modelling period. Only one capacity year was modelled (2025/26).
• What assumptions are made about plant retiring over the period modelled?	No plants were assumed to retire over the modelling period because only one capacity year was modelled. To the extent that retirements occur before 2025/26, these assumptions would reflect retirements identified in the 2021 GCS.
• For OCGT, ○ What are the assumed annual run time hours of OCGT plant in (a) Northern Ireland and (b) the Republic of Ireland.	This metric is provided in Section 7.2 of our report. The output of the modelling was that the OCGT unit only operated for 40 hours in the capacity year. We applied this finding to the OCGT reference units for both Northern Ireland and Ireland.
• For CCGT, ○ Does this change in future years, or is the load factor from 2025/26 assumed to continue for the duration of the lifetime of the asset? ○ What were the operating hours assumed for CCGT?	This metric is also provided in Section 7.2 of our report. The output of the modelling was that the CCGT unit operated for 65.5% of the time (c. 5,738 hours). We assumed for the purpose of providing estimates of Net CoNE that the load factor and revenues are maintained across the asset life. However, we also provided an indicative example of what the average IMR could be for a CCGT unit if IMR was to decline to zero after 10 years, to in part reflect the potential impact of lower operating hours.
For the BNE, it is unclear as to why the ARHL application for NI and Ireland is different given that limited run hour units exist in both jurisdictions?	This is discussed on p. 13 and Section 3.12 of our report. ARHLs are applied to relevant BNE candidates in Northern Ireland, reflecting our understanding of how the BAT provisions are interpreted by the Northern Ireland Environment Agency. For Ireland, we are guided by the SEM Committee's Information Note on licencing processes in Ireland for technologies other than a Combined Cycle Gas Turbine in regard to BAT Conclusions.[3]
On what basis is SEMC assuming that an uplift to IMR revenues to account for Administrative Scarcity Pricing should be included when CEPA excluded it?	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.

[3] https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-107%20Info%20Note%20re%20the%20Application%20of%20Annual%20Run%20Hour%20Limits.pdf

Question	Response
No model runs for 2026-27 were completed for IMR reasons and instead the results for the runs undertaken for the 2025/26 capacity year (for USPC) are being used to inform IMR. Are we correct in understanding that these 2025/26 runs would have been earlier in 2022 – what were the key running assumptions?	The model runs were undertaken for the 2025/26 capacity year primarily for the purpose of assessing applications for Unit Specific Price Caps (USPC) in the 2025/26 T-4 capacity auction. The modelling was undertaken in early 2022 (prior to Russia's invasion of Ukraine) using the available, validated SEM PLEXOS model, with updated gas and carbon price assumptions.
Should the 25% higher capability of reciprocating engines be with a view to reflecting the operational advantages of the reciprocating engines over an OCGT (the consultation implies it is the OCGT has operational advantages over the reciprocating engines?) (page 52)	No – the 25% value has been applied as intended but the explanatory text for this should read "to reflect the operational advantages of the *former*". The operational advantages listed are advantages which reciprocating engines have over OCGT.
CEPA state that "Conversely, the capacity of CCGT is assumed to be 25% lower than the OCGT assumptions to reflect the complexity, and generally lower efficacy, of providing frequency responses from a steam turbine". Should the underlined read "capability"? (page 52)	Yes – this sentence should refer to the "capability of CCGT".
Why are estimates of IMR for CCGTs in later years not available for this study, could PLEXOS not determine them? (page 57)	This analysis was constrained by the time and resources available prior to the consultation. We understand that the RAs are considering undertaking more and specific PLEXOS runs for the purpose of the final version of the report.
Can you please outline the inflation assumptions used for: a. 2022; and b. 2023-27? Will these inflation assumptions being updated to reflect recent market evidence?	As set out in Section 8.1.2 of our report, we have used a 2.0% long-term inflation expectation for both jurisdictions. This was consistent with previous BNE studies. In the report we recognised that inflation expectations were elevated relative to this long-term trend and that this will be reflected within nominal WACC parameters. We do not currently intend to move away from the use of a long-term inflation assumption for our modelling but may consider doing so subject to consultation responses.
We understand that the net CONE calculation is based on an assumed 20 years asset life. Could you please detail the assumptions and method for calculating the IMR for each year.	Section 7.1 on our report explains that for the IMR assumption we were provided with the results of wholesale market modelling undertaken by the RAs for the 2025/26 capacity year. We assumed for the purpose of providing estimates of Net CoNE that these revenues are maintained across the 2026/27 to 2035/36 period. However, we also provided an indicative example of what the average IMR could be for a CCGT unit if IMR was to decline to zero after 10 years.
a. What gas and electricity prices are assumed for each year of the analysis? How does this change over time?	The PLEXOS modelling was undertaken (by the RAs) using fuel curves from early 2022, before Russia's invasion of Ukraine. The same applies to the carbon price assumptions.

Question	Response
	The electricity prices were an output of the modelling for each hour. The prices do not change over time because only one capacity year was modelled.
b. What running hours / load factor are assumed for each technology in this model, in: i. the Republic of Ireland; and ii. Northern Ireland. How does this change over time? What assumptions are built into the model relating to annual run hour limitations (such has due to restrictions in planning decisions)?	Our assumptions are provided in Section 7.2 of our report. Our run hour assumptions for CCGT and OCGT are based on the energy market modelling which informed the IMR assumption, in which CCGT was running for 65.5% (c. 5,738 hours) of the time and the OCGT for only 40 hours (c. 0.4%). We assume that the reciprocating engine unit would have the same run hours as the OCGT, while the energy storage facility would have 80% availability. We applied the same assumptions across Ireland and Northern Ireland. These assumptions do not change over time because only one capacity year (2025/26) was modelled. However, we provided an indicative example of what the average IMR could be for a CCGT unit if IMR was to decline to zero after 10 years, to in part reflect the potential impact of lower operating hours. Annual run hour limits would apply to OCGT and reciprocating engines locating in Northern Ireland. However, with a run hour assumption of only 40 hours in a year, these limitations are not binding in this instance.
What technology is assumed to be the reference / marginal / price setting technology?	There is no single price setter as the marginal unit can vary from one hour to the next across the modelling period.
What assumed efficiency factors are used in each year of the analysis?	The key technical capabilities for generators are published as part of the SEM PLEXOS Model Validation (2021-2029) and Backcast Report. Only one capacity year (2025/26) was modelled.
What is the assumed efficiency of the price setting plant?	There is no single price setter as the marginal unit can vary from one hour to the next across the modelling period.
What assumptions do you include in your analysis about plant closures?	No plants were assumed to retire over the modelling period because only one capacity year was modelled. To the extent that retirements occur before 2025/26, these assumptions would reflect retirements identified in the 2021 GCS.
What RES penetration rate is assumed in this model? How does this change over time?	We have not analysed RES penetration because we were not responsible for the PLEXOS model runs. However, we understand that it is possible to calculate this from the publicly available, validated SEM PLEXOS model. There is no change over time because only one capacity year was modelled.
What assumptions around merit order position are assumed in this model?	The position of each unit in the merit order is a function of the fuel costs, heat rates and fuel transport costs used in the validated SEM PLEXOS model, updated using

Question	Response
	fuel and carbon price assumptions available in early 2022. We understand that the fuel costs involved a quarterly profile which in theory could lead to changes in the merit order over the modelled period (2025/26), but considering the technology mix present in the modelling it is unlikely that there would have been any change in practice.
How is the impact of future changes to merit order position taken into account in the analysis?	This was not considered through the modelling because it only considered a single capacity year (2025/26). We provided an indicative example of what the average IMR could be for a CCGT unit if IMR was to decline to zero after 10 years, to in part reflect the potential impact of lower operating hours which could result from changes in the merit order.
How assumptions are used on the impact of energy storage in the IMR calculation? How does this change over time?	The validated SEM PLEXOS model includes energy storage units which we understand reflect the 2021 GCS. There is no change over time because only one capacity year was modelled.
How do you take account of the uncertainty about how DS3 revenues will evolve over the lifetime of the various technology types included in the study?	This is covered in Section 7.2 of our report. We note that there is general uncertainty around the market settings and price formation under the future system services arrangements which could push prices in either direction. We settled on an assumption relative to 2021/22 Tariffs based on the qualitative factors identified and assumed that this would remain constant over time.
What running hours are assumed for each technology in the DS3 revenue estimation, for each year of the analysis?	Our assumptions are provided in Section 7.2 of our report. Our run hour assumptions for CCGT and OCGT are based on the energy market modelling which informed the IMR assumption, in which CCGT was running for 65.5% (c. 5,738 hours) of the time and the OCGT for only 40 hours (c. 0.4%). We assume that the reciprocating engine unit would have the same run hours as the OCGT, while the energy storage facility would have 80% availability.
Technology capability assumptions sourced from Eirgrid are used as a starting point in the CEPA/Ramboll analysis. CEPA/Ramboll notes that these factors are estimated based on historical data of contracted capabilities. a. Can you please provide the time period for the Eirgrid analysis?	We have requested this information from Eirgrid but it was not available in time for publishing these answers.
Has CEPA/Ramboll compared the 20% discount applied to 2021/22 tariffs to other sources?	In Section 7.2 of our report we noted the outcome of Volume Capped procurement where the value of the contracts was approximately 18% of the value (i.e., a c. 83% discount on the prevailing tariffs) but we considered that this discount would be too high for the BNE for reasons provided.

Question	Response
	We noted that this assumption is based on a judgment call which stakeholders may be able to refine through the consultation. Stakeholders are encouraged to provide us with other sources which may be relevant to this assumption.
Can you please provide the beta results for each company used in your analysis?	0.36 Albioma 0.58 Orsted 0.49 ERG SpA 0.56 Falck Renew 0.20 Alerion Cleanpower 0.47 PNE AG 0.45 EDP Renovaveis 0.36 ENCAVIS 0.49 SCATEC 0.33 Voltalia 0.43 Grenergy 0.57 Engie 0.57 RWE 0.88 EDF 0.24 Ceres Power 0.45 Drax 0.18 Solarparken 0.99 Eolus Vind 0.42 Arise AB 0.54 Naturel Yenilenebilir 0.72 Audax
How has interest during construction been calculated? a. What is the loan on which interest during construction has been calculated? b. What is the assumed capex phasing for CCGT and OCGT plants?	As set out in Section 4.9, the interest on the loan has been estimated using the estimated cost of debt (no premium has been assumed for IDC). We use a three-year period for CCGT and a two-year period for other technology. We assume equal phasing over these construction periods.

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