Energia response to SEM Committee Consultation Paper SEM-20-006

Capacity Remuneration Mechanism 2024/25 T-4 Capacity Auction Parameters and Compliance with the Clean Energy Package

20 March 2020

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Executive Summary

Energia welcomes the opportunity to respond to this Consultation Paper (SEM-20-006) on the T-4 capacity auction for CY2024/25 and compliance with the Clean Energy Package. This response makes the following key points:

Existing Capacity Price Cap (ECPC) and Net CONE

- Energia fully endorses the EAI response to the Consultation Paper and its firm position against any potential reduction to the Existing Capacity Price Cap (ECPC) on the basis that it is not justified; would heighten the perception of regulatory risk (raising the cost of capital); and would needlessly interfere with proper market functioning, contrary to the principles in Articles 3 and 10 of Regulation 2019/943. Rather than decrease ECPC, there is a strong, logical and justifiable case for the ECPC to be adjusted upwards for all future auctions.
- Any rational investor must adopt a prudent view of future costs, revenues and risks, especially looking 4 years ahead (i.e. for the CY2024/25 capacity delivery period). Ultimately the shareholders will be making the decision whether to keep the plants open and invest in their continued operations and this will be determined by their view alone of net going forward costs taking all associated risks and uncertainties into account. There is ample evidence, given past and recent events, that unforeseen economic shocks can and do happen, with severe negative consequences for generators. It is therefore vital that a conservative view of NGFC is appropriately reflected in the ECPC. The current multiple of 0.5 times Net CONE clearly does not achieve this[1], therefore it should be increased.
- Energia notes that the Regulatory Authorities (RAs) do not intend to review Net CONE for the 2024/25 T-4 auction. However, the current Net CONE is outdated[2] and seems incompatible with EU law[3], consequently we suggest that the RAs:
    1. Commit to regular review of Net CONE going forward to reflect changing cost and financing conditions, following extensive consultation with industry, and in the meantime apply some form of indexation to Net CONE if it is not re-calculated for CY2024/25.
    2. Determine what type of plant constitutes a compliant BNE and calculate the associated Net CONE. In the interests of expediency for the T-4 auction in January 2021, this could be based on a compliant reference

[1] Neither does the 10% margin for estimation uncertainty in Unit Specific Price Cap determinations, particularly where the RAs do not adopt a conservative view of NGFC to being with

[2] We note for example that many of the assumptions which were decided in 2018 could be significantly different for a new build developer in the current environment (including EPC pricing, TUOS, Rates, Cost of Capital, DS3 revenues, IMR, Insurance etc.). It should also be recognised that Grid Code is much more challenging than in GB. For example, the requirement for a minimum stable generation of 35% of Registered Capacity – makes compliance with environmental legislation extremely challenging – especially in relation to NOx emissions that may require abatement investment, which is expensive.

[3] Specifically, the current Net CONE (determined by the RAs in September 2018, with support from Poyry) is based on a distillate peaking reference plant (a Siemens SGT5-2000E unit) that we understand is not compliant with the CO_2 emission limits in EU Regulation 2019/943 introduced in June 2019 – i.e. it is our understanding that it emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity.

technology from those considered in September 2018 when Net CONE was last calculated, as summarised in Table 9 of SEM-18-156.

Treatment of Constraints

- Energia strongly supports the proposal to include transmission constraints within the T-4 auction, and we believe this is clearly justified for Dublin and Northern Ireland where there are local transmission capacity delivery constraints affecting security of supply and the need is "clear and significant".
- Energia does not support the suggestion allowing new capacity seeking a multi-year contract to compete with existing capacity for a pay-as-bid Reliability Option. This would be clearly inefficient given the emphasis placed elsewhere on resolving grid constraints (both in the context of State aid approval and submissions made to the EU in compliance with Regulation 2019/943). The bias in favour of new entry would also introduce the possibility of delays in construction putting security of supply at risk.

Withholding Demand from T-4 Auctions

- Energia would discourage withholding capacity procured in the T-4 auction for the corresponding T-1 auction, particularly in constrained areas. This will artificially lower T-4 auction prices and discourage new entry by reliable generation, in favour of less reliable DSU capacity. To provide the required degree of security in advance, it would be prudent not to withhold any demand at T-4 in constrained areas.

Auction Format D

- In principle, Energia has no strong preference between Auction Format C and D. However, we share EAI's concerns over the deliverability of Auction Format D within the limited 9 months' available and we thus favour Auction Format C for practical reasons.

Tolerance Bands Applied to De-Rating Factors

- In the light of evidence provided previously in response to SEM-17-027, Energia would welcome the introduction of flexibility into the tolerance bands for Gas Turbines.

Need for Greater Transparency

- Energia calls for greater transparency and consultation in a number of areas, including the level of reserves to be included, and the specific volumes proposed to be withheld for demand uncertainty and DSU participation within the demand curve and each of the LCCAs in the T-4 auction for CY2024/25.

Options for Compliance with CO_2 Emission Limits in Regulation 2019/943

- Article 22(4) requires that the design of the capacity mechanism must require that if the applicable emissions threshold is breached the relevant generation capacity must not receive payments (which necessarily incudes the repayment of capacity payments already received in the year that the breach first occurred) and must not be entitled to receive future payments. If the design of the capacity mechanism fails to reflect these principles it would be incompatible with EU Regulation 2019/943.

- While a run hour limit is not a feature of EU Regulation 2019/943, the emissions limits in EU Regulation 2019/943 and their impact on entitlement to capacity payments may mean that the emissions limits become a *de facto* run hour limit due to generator behaviour, whether or not this is permissible under the Grid Code or the BCOP. The fact that this is an emissions limit rather than a run hour limit at law, means that Option 2 is incompatible with EU Regulation 2019/943. Option 1 can be compatible so long as plants which exceed the emissions limits cease to be eligible for capacity payments. Under Option 1 (if implemented properly) it is also less likely that the applicable plants will exceed the emission limits. Option 1 has other distinct advantages over Option 2.
- In this response, we demonstrate a "cliff-edge effect" on security of supply of having significant quantities of run-hour-limited plant in the capacity portfolio, which is clearly undesirable. If the run-hour limited plant continues to participate in the shorter term, we strongly believe that Option 1 is more appropriate.
- Under Option 1, the limitations of the plant in terms of its effective contribution to capacity are recognised up-front. Setting appropriate derating factors makes management of the run hours by the TSO in dispatch more acceptable and will also maximise the contribution of the plant to overall capacity requirements and will reduce the risk of the "cliff-edge" being reached.
- Under Option 2, the effective contribution of the plant to capacity is clearly overstated. The derating factors for other resources with significant running limitations (such as storage) are adjusted to recognise the diluted capacity contribution. If the derating is left "voluntary", there is a significant risk that the plants would not de-rate on the expectation (or hope) that:
    1. Scarcity events might rarely occur;
    2. They can reduce their run hours by inflating balancing market offer prices (if permitted);
    3. The TSO will husband run hours so they never reach the run-hour limits;
    4. They can back off risk through secondary trading with other plant;
    5. Potential loss is limited by "stop loss" limits.

  It is also worth noting that where voluntary adjustment of derating factors is allowed for IED affected plant, it is rarely (if ever) used.

Timing for Implementation of Option 1

- Article 22(4) in Regulation 2019/943 applies to existing capacity from 1st July 2025 *at the latest*. Thus, it can be applied sooner if desired. Along these lines, the British government is considering whether to apply the carbon emission limits from 1st October 2024 or 1st July 2025 to existing capacity.
- There is a strong argument that the additional derating factors (Option 1) should apply from 1st October 2024, as it is the earliest practicable date, even though run-hour restrictions may in practical terms actually have kicked in earlier as plant positions itself during a pre-qualification period prior to 1st July 2025.
- Deferring implementation of Option 1 to 1st October 2025 is not an option that should be contemplated in our view. Instead, the following alternative could be considered:

1. Reduce capacity year 2024/25 to 9 months (ending 30th June 2025)
2. Apply Option 1 to subsequent and future auctions, beginning with capacity year 2025/26 (beginning 1st July 2025 and ending 30th September 2026)
3. Focus on maximising the lead time of the 2025/26 T-4 auction, given the volume of new capacity required to replace the de-rated capacity of limited run-hour plant.

Long Stop Date

- Energia does not believe that the Long Stop Date should be reduced for new entry below 18 months, including for the following reasons:
    1. Generation in Ireland is required to run on dual fuels. This requires additional equipment and also commissioning time;
    2. Commissioning on to the Irish grid is much more difficult than in GB. This is because of the impact one generator has in relation to system security and has to be managed by the system operator; and
    3. Risks in relation to longer lead times following the Coronavirus.

  We do however agree that the system is heading into a period of significantly elevated risk and uncertainty given expected capacity shortfalls by 2025/26; the need for investment in new capacity; the continued need for considerable existing generation to support the low carbon transition; the true performance of existing resources that has hitherto been largely untested; and the potential for a “cliff-edge” effect if limited run-hour plant is fully utilised.

- Rather than reducing the Long Stop Date, we believe other measures should be adopted in recognition of this period of elevated risk, specifically:
    1. Setting appropriate derating factors, as per Option 1 in the Consultation Paper for *de facto* run-hour limited plant;
    2. Procuring additional volumes in earlier or additional auctions;
    3. Reducing the amount of capacity withheld from T-4 auctions; and
    4. Carrying out reviews of the overall risks associated with the future capacity portfolio and taking mitigating actions as appropriate.

1. Introduction

Energia welcomes the opportunity to respond to the SEM Committee Consultation Paper SEM-20-006 titled "Capacity Remuneration Mechanism 2024/25 T-4 Capacity Auction Parameters and Compliance with the Clean Energy Package" (the "Consultation Paper").

The remainder of this response is structured as follows. Section 2 provides comments on the auction parameters, auction format, treatment of constraints, and transparency. Section 3 responds to the proposals in the Consultation Paper for complying with the Clean Energy Package. Finally, section 4 responds to the specific questions in the Consultation Paper.

2. Proposed parameters for 2024/25 capacity auction

2.1 Existing Capacity Price Cap and Net CONE

The Consultation Paper refers to previous auction outcomes and the SEM Committee's opinion *"that the ECPC may have become materially price affecting, rather than a bid limit within the auction"*. With reference to this, the Consultation Paper states that the SEM Committee *"will observe the results of the 2023/24 T-4 capacity auction…and remains open to reducing the ECPC to 0.4 times Net CONE for the 2023/24 T-4 auction."*

Energia fully endorses the EAI response to the Consultation Paper and its firm position against any reduction to the Existing Capacity Price Cap (ECPC) for the 2024/25 T-4 capacity auction, or indeed any future auctions. We strongly urge the RAs to consider the detailed reasoning put forward by EAI, which can be summarised as follows:

- The RA have not provided any convincing rationale to justify such an arbitrary review of the ECPC parameter at a time when significant investment in new and existing assets is required in order to meet our decarbonisation targets and mitigate against the forecast capacity shortfalls for 2025/26 in EirGrid's latest Generation Capacity Statement (GCS)[4].
- Fundamentally, a reduction of the ECPC would significantly heighten the perception of regulatory risk in this market (raising the cost of capital) and would needlessly interfere with proper market functioning, contrary to the principles in Articles 3 and 10 of Regulation 2019/943.
- A competitive market is at the core of the existing State aid approvals (SA44464 & SA44465), and interference with the ECPC with the clear aim of influencing market price outcomes, is contrary to the spirit of those approvals and Regulation 2019/943 and the objectives of market liberalisation.
- Given the expected capacity shortfalls by 2025/26, there is not only need for investment in new capacity but there is a continued need for considerable existing generation to support the low carbon transition. Introducing the regulatory risk that a downward review of ECPC would entail, is not only

[4] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

unnecessary and unjustified but could potentially increase security of supply concerns and consumer costs in the process.

- The USPC process is not a valid substitute for setting the ECPC too low. Apart from its other flaws, this is because the USPC process expressly rules out recovery of so-called sunk costs that would neither be denied from or discounted by rational actors in a competitive market.
- EAI is of the view that contrary to the suggested potential revision of the ECPC, there is in fact reason to review the ECPC upwards and at the very minimum retain it at 0.5 BNE. The stark capacity shortfall figures in EirGrid's GCS support this assertion.

Furthermore, as previously called for by EAI, the SEM Committee should raise the ECPC considering that the current netting of DS3 revenues from the BNE calculation process removes the incentive to invest capital in the provision of system services necessary to decarbonise the power system.

It is also worth adding to the above that the capacity auction rules prevent the clearing price in the auction rising above the ECPC unless new capacity enters the market and sets the clearing price. However, in conditions of shortage the competitive market price of an auction would be higher than ECPC in order to encourage new entry. In such conditions the ECPC level is therefore holding auction clearing prices below the efficient and competitive level. This therefore means the ECPC should only be applicable in conditions of excess supply and should only apply to market segments facing these conditions, and where these conditions do not exist the ECPC is undesirable and has a price depressing impact, contrary to the principles in Articles 3 and 10 of Regulation 2019/943.

Energia has consistently held the view, as reflected in responses to SEM-16-073, SEM-18-028, and SEM that the ECPC multiplier is set too low. Energia is strongly opposed to any reduction from this already low level. To do so would further hinder cost recovery (thereby putting security of supply at risk and increasing the cost of capital) and would increase regulatory intervention in the market where it is neither justified nor proportionate.

Any rational investor must adopt a prudent view of future costs, revenues and risks, especially looking 4 years ahead (i.e. for the CY2024/25 capacity delivery period). Ultimately the shareholders will be making the decision whether to keep the plants open and invest in their continued operations and this will be determined by their view alone of net going forward costs taking all associated risks and uncertainties into account. There is ample evidence, given past and recent events, that unforeseen economic shocks can and do happen, with severe negative consequences for generators. It is therefore vital that a conservative view of NGFC is appropriately reflected in the ECPC. The current multiple of 0.5 x Net CONE does not achieve this, therefore it should be increased.

Energia also notes that the Regulatory Authorities (RAs) do not intend to review Net CONE for the 2024/25 T-4 auction. However, current Net CONE is outdated[5] and

[5] We note for example that many of the assumptions which were decided in 2018 could be significantly different for a new build developer in the current environment (including EPC pricing, TUOS, Rates, Cost of Capital, DS3 revenues, IMR, Insurance etc.). It should also be recognised that Grid Code is

seems incompatible with EU law[6]. Consequently, the RAs should determine what type of plant constitutes a compliant BNE and calculate the associated Net CONE. In the interests of expediency for the T-4 auction in January 2021 we suggest this could be based on a compliant reference technology from those considered in September 2018 when Net CONE was last calculated, as summarised in Table 9 of SEM-18-156.

Furthermore, Energia calls on the RAs to commit to a regular review of Net CONE to reflect changing cost and financing conditions, following extensive consultation with industry, and in the meantime suggest that some form of indexation should be applied to Net CONE if it is not re-calculated for CY2024/25.

2.2 Treatment of constraints in T-4 auction

The Consultation Paper contains two separate proposals regarding the treatment of constraints, which Energia responds to below.

Proposal 1: Transmission constraints will continue to be included in the 2024/25 T-4 auction

Energia strongly supports the proposal to include transmission constraints within the T-4 auction, and we believe this is clearly justified for Dublin and Northern Ireland where there are local transmission capacity delivery constraints affecting security of supply and the need is "clear and significant"[7].

The State aid decision of the European Commission also seems to require that the auction take transmission constraints into account where they are clear and significant. In these circumstances, a certain amount of generation needs to be secured in a constrained area, to meet all constraints requirements for that area. Capacity procured through the T-4 auction will displace other generation, thereby avoiding "over-procurement". If transmission constraints are not included in the CRM, then more local generation will have to be procured through other means (and will not displace other generation). This will create additional over-procurement, contrary to the objectives set out in the State aid decision.

Proposal 2: For the 2024/25 capacity auction, the SEM Committee remains open to allowing the auction to solve using multi-year New Capacity

The above question was the subject of a previous SEM Committee consultation (SEM-18-028) concerning the T-4 auction for CY2022/23 to which Energia responded. Energia's views against any such proposal remain unchanged. Please see Energia's response to SEM-18-028 for further details.

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much more challenging than in GB. For example, the requirement for a minimum stable generation of 35% of Registered Capacity – makes compliance with environmental legislation extremely challenging – especially in relation to NOx emissions that may require abatement investment, which is expensive.

[6] The current Net CONE (determined by the RAs in September 2018, with support from Poyry) is based on a distillate peaking reference plant (a Siemens SGT5-2000E unit) that we understand is not compliant with the CO_2 emission limits in EU Regulation 2019/943 introduced in June 2019 – i.e. it is our understanding that it emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity.

[7] Note however Energia's response to SEM-19-048 which raised significant concerns about the lack of justification and arbitrary nature of the proposal to introduce an additional LCCA for the 'Rest of Ireland' for the 2023/24 T-4 auction.

In summary, allowing new capacity seeking a multi-year contract to compete with existing capacity for a pay-as-bid Reliability Option is very difficult to reconcile with the emphasis that has been placed elsewhere on reducing grid constraints in the SEM. For example, the European Commission's understanding in the State aid decision was that grid constraints were temporary and would be resolved to a large extent by 2024[8]. And more recently, the Implementation Plan submitted by DCCAE to the European Commission on 16th December 2019 in compliance with Regulation 2019/943 stated that *"reducing longer [grid] constraints…are considered vital by EirGrid to reduce the need to incorporate locational constraints with (sic) future CRM auctions"*. [9]

Bearing in mind the stated plan to reduce constraints, it would be counterintuitive and clearly inefficient to allow new entrants bidding for multi-year contracts (of up to 10 year) to compete with existing capacity (limited to 1 year contracts) on a constrained-on basis i.e. it would bias the selection process in favour of new entry, even when the new entry prompted by multi-year contracts would be inefficient and would raise costs for consumers, relative to using existing capacity. The bias in favour of new entry will also introduce the possibility of delays in construction putting security of supply at risk.

The SEM Committee itself recognised this danger in paragraph 2.2.9 of SEM-18-028 and again in paragraph 3.4.8, where the SEM Committee asserted without explanation that the risk of stranding is higher for "out-of-merit lumpiness solutions" than for solutions to transmission constraints. However, that does not negate our conclusion: behind transmission constraints, apparently low-priced multi-year contracts are likely to prove unnecessarily expensive and to become stranded.

Ultimately, we conclude that the status quo (using multi-year contracts only when single-year bids are insufficient to resolve constraints) should be retained, as this provides the best chance of giving efficient outcomes that are in consumers' interests.

2.3 Withholding demand from T-4 auction

The Consultation Paper states that the final Demand Curve for the 2023/24 T-4 auction has yet to be determined and will be published in the Final Auction Information Pack. Details are provided on adjustments made to the Demand Curve for the 2022/23 T-4 auction, including withholding for demand uncertainty and DSU participation. However, there is no indication of demand to be withheld from the upcoming T-4 auction. As discussed in more detail in Table 1, we believe this should be consulted upon and

Energia has consistently argued against withholding demand from T-4 auctions for the corresponding T-1 auction[10]. This will artificially lower T-4 auction prices and discourage new entry by reliable generation, in favour of less reliable DSU capacity. This is especially pertinent at a time when significant investment in new capacity is

[8] See State aid No. SA.44464 (2017/N) – Ireland Irish Capacity Mechanism, para 155.
[9] See section 4.4 of DCCAE's submission for further details. This refers to a number of major upgrades or extensions to the Irish electricity system currently planned by EirGrid, including the North South Interconnector and the West Dublin Project.
[10] See response to SEM-18-028 for further details.

required in order to meet our decarbonisation targets and mitigate against the risk of forecast capacity shortfalls for 2025/26 materialising[11].

The TSO will be particularly concerned with securing supplies in advance within constrained areas, withholding demand from the T-4 auction will undermine this. Furthermore, the price-depressing effect of withholding demand at T-4 provides a signal to encourage exit, which is not desirable within constrained areas, and should be focused within areas with excess supply. To provide the required degree of security in advance, it would be prudent not to withhold any demand at T-4 in constrained areas because the security risks of being left with insufficient capacity in constrained areas is too great as the “pool” of potential resources to make up the gap at T-1, is more limited.

2.4 Auction format D

The Consultation Paper seeks comments on moving from auction format C (heuristic based approach) to format D (full combinatorial approach). In principle, Energia has no strong preference between these auction formats as they should both deliver the same outcomes. However, we share EAI’s concerns over the deliverability of auction format D within the limited 9 months’ available and we thus favour auction format C for practical reasons.

2.5 Tolerance bands applied to De-Rating Factors

In the CRM Capacity Requirement and De-Rating Factor Methodology Decision paper (SEM-16-082), the SEM Committee decided that, with the exception of DSUs, the tolerance bands will be set to zero for the transitional auctions, with the decision to be reviewed for the enduring auctions once the enduring value of Full Administered Scarcity Price has been determined. The SEM Committee is proposing to retain this decision for the 2024/25 T-4 auction, but requests comments on introducing flexibility into the tolerance bands.

Energia maintains (for reasons outlined in response to SEM-17-027) that meaningful tolerance bands for de-rating factors should be re-instated as provided for in Decision Paper SEM-15-103. In the confidential annex of our response to SEM-17-027, we provided supporting evidence that there is “legitimate technical variation” to justify a meaningful (positive) tolerance band for Gas Turbines in particular. In the light of this evidence we would welcome the introduction of flexibility into the tolerance bands for Gas Turbines.

2.6 Need for greater transparency

Energia calls for greater transparency and consultation in a number of areas, including the level of reserves to be included[12], and the specific volumes proposed to be withheld for demand uncertainty and DSU participation within the demand curve and each of the LCCAs in the T-4 auction for CY2024/25. As discussed above, it remains Energia’s position that there should be no withholding of capacity from the T-4 auction to avoid inappropriately depressing clearing prices and to avoid undue risk

[11] See Generation Capacity Statement (GCS) 2019-2028.

[12] The RAs previously gave a commitment in SEM-18-173 to consult on the proposed level of reserves in future parameters consultations for T-4 auctions.

to security of supply (where this risk is particularly acute within a smaller area such as the Dublin LCCA).

3. **Compliance with the Clean Energy Package**

As a preliminary comment, we note that the Consultation Paper focuses exclusively on compliance with Article 22(4) of Regulation 2019/943, however, there are other aspects of the Regulation relevant to capacity markets that we believe should also be considered to ensure compatibility with EU law, including Articles 3, 3n; 10(4); 11; 22(3)I; 23; 24; 25 and 26.

The Consultation paper raises several complex issues regarding treatment of plant with CO_2 emissions limits, which has the potential to impact on the overall effectiveness of the CRM and on security of supply to customers. These include:

1. The application of the Clean Energy Package, and the associated treatment of affected plant in the market, in dispatch and in availability declarations;
2. The extent to which limited-run hour plant can effectively contribute to capacity requirements; and
3. The interaction with other energy limited resources (particularly storage), as both will tend to be targeted at peak demand hours.

We discuss each of these issues below which largely forms the basis for our response to the specific questions in the Consultation Paper in section 4 of this response.

3.1 The application of the Clean Energy Package, and treatment of plant in dispatch and availability

Article 22(4) of Regulation (EU) 2019/943 of 5th June 2019 on the internal market for electricity (EU Regulation 2019/943) provides that:

> "*Capacity mechanisms shall incorporate the following requirements regarding CO_2 emission limits:*
>
> *(a) from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;*
>
> *(b) from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity and more than 350 kg CO_2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism.*"

The detailed application of certain elements of this Article and the precise impacts on the relevant generation resources is not fully clear at this stage. However, there are certain aspects of this Article which are unequivocal, specifically that any capacity mechanism must prohibit both (i) receipt of payments; and (ii) commitments for future payments, to generation capacity which breaches the emissions thresholds specified in this Article. Put another way, this Article requires that the design of the capacity mechanism must require that if the applicable emissions threshold is breached the relevant generation capacity must not receive payments (which necessarily incudes the repayment of capacity payments already received in the year that the breach first occurred) and must not be entitled to receive future payments. If the design of the capacity mechanism fails to reflect these principles it would be incompatible with EU Regulation 2019/943.

The Consultation Paper assumes for the purposes of the discussion that the plant is limited to 400 hours running in each year, but also notes the ACER "technical guidance" which may (if adopted) result in a different application of the limits[13].

We agree that the 400-hour figure (whether applied in each year or on some rolling-average basis) is about right, given the technical characteristics of the relevant plant and the relevant emissions limits. For the purpose of the discussion below, we have assumed (similar to the Consultation Paper) the annual "limit" of 400 hours in a year, but the same issues would arise even under a somewhat different implementation (such as using a rolling average over a number of years).

The following points are relevant:

1. EU Regulation 2019/943 does not, in our view, limit the run hours of a plant per se, but rather only prevents the plant being able to *"receive payments or commitments for future payments under a capacity mechanism"*. The reference to being *"committed"* in this Article pertains to commitment *"under a capacity mechanism"* and not commitment in the context of dispatch.
2. The Consultation Paper contemplates that once the run hour limit is reached, the plants would no longer be available. However, for the reasons outlined above, the Regulation does not require this. Rather it requires that the capacity market design provides that any such plant should not be remunerated under the capacity mechanism in the year that the emissions limit is breached or in subsequent years. This does raise the issue of whether it is appropriate or permissible that the plants would be declared unavailable (even though still technically available) in order to protect current and future earnings under CRM (which they would have a compelling incentive to do). We understand that under the Grid Code it would not be permissible for such plant to do so.
3. A related issue is treatment of the plants in the market and dispatch. To what extent are the plants allowed to inflate balancing market offers in order to limit their running? Also, historically the TSO in formulating the dispatch schedule, would husband the available run hours on run-hour or energy-limited plant, in order to save them for times when they are most required (on the grounds of security of supply). This in effect makes them the "last plant on" even if short-term economics suggest differently. Is it intended that this will apply to the run-hour limited plant in the future?
4. There is clearly a very strong incentive on plant which is approaching its emissions limit, to cease running in order to preserve both its CRM revenues in the current year, and to maintain its ability to participate in CRM in subsequent

[13] We note that the British government intends to require that the yearly limit is calculated on the basis of emissions across twelve months (one year), rather than the average of the three preceding years proposed in the ACER opinion. They have taken the view that the ACER opinion is 'non-binding', so there is scope to implement GB-specific arrangements that vary from the opinion where there is good reason to do so.

years. If the emissions limited plant has the right to declare itself unavailable when it reaches or approaches the emissions "limit", this creates a serious "cliff-edge" effect for security of supply. Consider a scenario where due to a period of relatively poor availability performance early in the year, the run-hour-limited plant is being utilised. A point is reached at which the available run hours have been used (which will happen at or about the same time for all plants) and up to a further 1,200 MW of plant becomes unavailable. This means that overnight it changes from a "not great but managed" situation, to a calamitous one with significant quantities of demand interruption.

It therefore appears that while a run hour limit is not a feature of EU Regulation 2019/943, the emissions limits in EU Regulation 2019/943 and their impact on entitlement to capacity payments may mean that the emissions limits become a *de facto* run hour limit due to generator behaviour, whether or not this is permissible under the Grid Code or the BCOP. For the purposes of this response we have continued to refer to run hour limits because this is the language used in SEM-20-006. However, the fact that this is an emissions limit rather than a run hour limit at law, means that Option 2 is incompatible with EU Regulation 2019/943. Option 1 can be compatible so long as plants which exceed the emissions limits cease to be eligible for capacity payments. Under Option 1, if implemented properly[14], it is also less likely that the applicable plants will exceed the emissions limits. Option 1 has other distinct advantages over Option 2 that we explain further below.

3.2 Contribution of run-hour limited plant to capacity requirements

The Consultation Paper presents an illustrative example of the effect of run hours limitation:

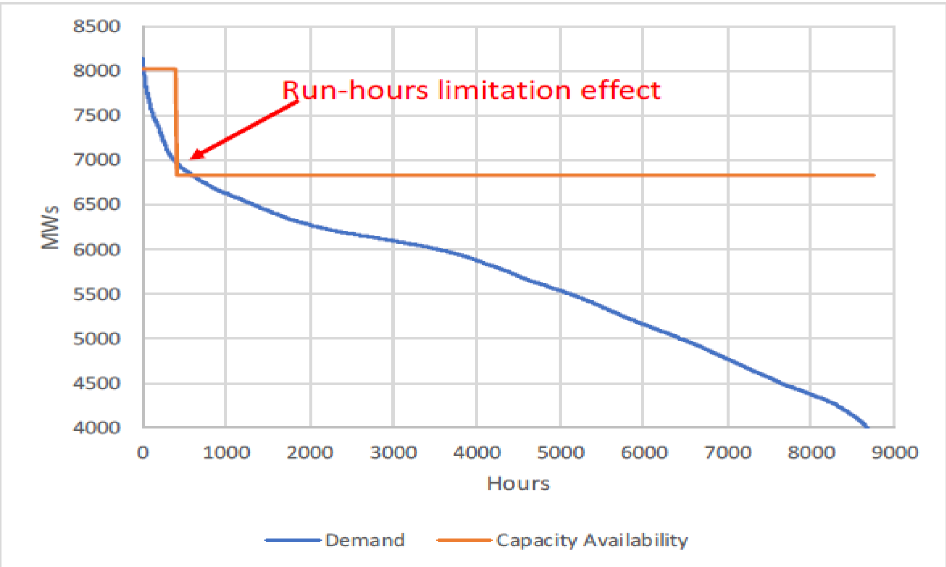


Figure 1: Illustrative Example of run-hours limitation effect.

[14] Such that the reduced effective contribution of the applicable plant to capacity requirements is recognised in the additional de-rating factors and additional alternative capacity is procured to make up the difference (which would not have been procured in Option 2), which in theory should result in no need for the run-hour limited plant to run for more than the target hours.

The illustration is based on having 1,200 MW of resources limited to 400 run hours per year (600 MW of distillate generation, and 600 MW of DSU capacity). From review of 2019 demand data, the illustration appears to be broadly correct; in 2019 there were some 680 hours when the demand was within 1,200 MW of the system peak hour demand.

On this basis, the effective capacity contribution of the 1,200 MW of run hour limited resources is already compromised, as they cannot run for the required number of hours. Presumably the duty would have to be shared around among the available resources in some way, thus meaning that each of the resources can only contribute its capacity for a portion of the required hours. It is also important to note that the effective contribution will be further impacted as the available run hours will be "used up" by other effects:

1. The highest demand hours of the year are distributed over a significant number of days and peaks. Due to forecast variations and practicalities of dispatching the resources, they will use up run hours getting "on" and "off" before and after peak hour periods;
2. Run hours will be used during availability and other operational testing of the resources.

A still more important consideration is the interaction with other energy limited resources, particularly storage.

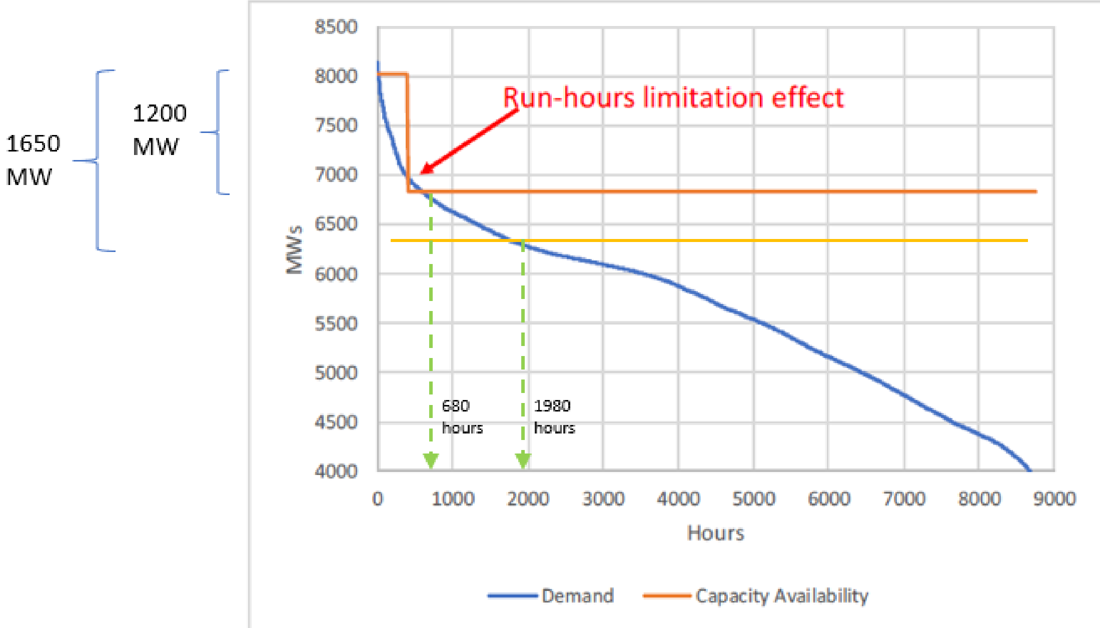
3.3 Interaction with other energy-limited resources

There is expected to be considerable growth in the amount of energy-limited storage plant in the coming years. In addition to the Turlough Hill Pumped Storage station (292 MW), there is already some 150 MW of battery capacity (80 MW de-rated) contracted under CRM T-4 CY2022/23, with storage times between one and two hours. It is generally expected that the quantity of battery storage within the overall resource portfolio will increase significantly in the medium to longer term, in light of enhanced RES targets and battery technology developments. There is also a possibility of other storage projects including further pumped storage.

The importance of this is that while the illustrative example given as Figure 1 in the Consultation Paper works if the 1,200 MW of run-hour limited plant were the only plant to be considered, there are other energy limited resources (pumped storage and battery storage) which will in effect be providing a similar "duty", i.e. filling in the "top end" of the load duration curve.

Analysing the interaction between the different run-hour and energy-limited resources and the overall impact on the effective capacity contributions of both, would be a complex undertaking. As a simple illustration, were a further 450 MW[15] to be included in the category of run-hour limited plant, the applicable period when running from the pool rises from approximately 680 hours to about 1,980 hours.

[15] The approximate capacity of Pumped Storage and Battery Storage Plant participating in CRM CY22/23. Note this is expected to rise further in future years.



While this is a somewhat simplistic illustration of the issue, it does show that the interaction is significant. As you include additional energy limited resources, the duty (number of service hours) required from the resources in aggregate increases significantly. This will reduce the effective capacity contribution of energy- or run-hour limited plant collectively. Also, it is likely that the quantities of energy limited storage plant will rise further, which will add to the issue. This needs to be considered in setting the derating factors for the run-hour limited resources associated with CO_2 emissions limits.

4. Response to specific Consultation questions

Which of Option 1 (allow high CO_2 emitting plant to participate in the CRM, but be subject to additional derating) and Option 2 (make no changes to the CRM, but ensure that any unit with emissions exceeding 550g CO_2 / kWh comply with CEP annual run-hours limitations) is your preferred approach?

Energia Response:

Firstly, we note that due to the “cliff-edge” issue described above, the inclusion of significant quantities of run-hour-limited plant in the capacity portfolio is undesirable in the longer term (particularly if the plant is permitted to declare itself unavailable when its run hour “limit” is reached).

If the run-hour limited plant continues to participate in the shorter term, we strongly believe that Option 1 is more appropriate.

Under Option 1, the limitations of the plant in terms of its effective contribution to capacity are recognised up-front. Setting appropriate derating factors (which must include consideration of the interaction with other energy-limited resources as they will all “cluster” at the top-end of the load-duration curve), makes strategies such as the husbanding of the available run hours at or in anticipation of times of capacity shortage, more acceptable. Management of the run hours by the TSO in dispatch will also maximise the contribution of the plant to overall capacity requirements and will reduce the risk of the “cliff-edge” being reached.

Under Option 2, the effective contribution of the plant to capacity is clearly overstated. The derating factors for other resources with significant running limitations (such as storage) are adjusted to recognise the diluted capacity contribution. If the derating is left “voluntary”, there is a significant risk that the plants would not de-rate on the expectation (or hope) that:

1. Scarcity events might rarely occur;
2. They can reduce their run hours by inflating balancing market offer prices (if permitted);
3. The TSO will husband run hours so they never reach the run-hour limits;
4. They can back off risk through secondary trading with other plant (especially larger portfolio holders);
5. Potential loss is limited by "stop loss" limits.

It is also worth noting that where voluntary adjustment of derating factors is allowed for IED affected plant it is rarely (if ever) used, and for other plant it is not permitted[16].

The question of whether the plant is permitted to declare itself unavailable in order to protect its current or future CRM revenues (even though still technically available and not prevented from running by EU Regulation 2019/943), is relevant to both Options 1 and Option 2. The Question posed in the Consultation Paper implies that this would be a requirement under Option 2, which makes Option 2 still more unsuitable as the potential for the “cliff-edge” effect, with calamitous consequences for supply interruptions, then comes into play.

If the additional de-rating is applied, should it be applied for the 2024/25 capacity year, or held until the 2025/26 capacity year? Alternatively, should the duration of the 2024/25 capacity year be reduced to nine months?

<u>Energia Response:</u>

Article 22(4) in Regulation 2019/943 applies to existing capacity from 1 July 2025 *at the latest*. Thus, it can be applied sooner if desired. Along these lines, the British government is considering whether to apply the carbon emission limits from 1 October 2024 or 1 July 2025 to existing capacity.

The date from which the additional derating factors should apply depends on the intended implementation of the mechanism. Arguably, the additional derating factors should take effect not from 1st July 2025, but from the start date of the pre-qualification period over which the emissions of the plant is assessed to determine its ability to participate in capacity mechanisms post-2025. Plant will wish to limit its run hours from the start of the pre-qualification period, in order to prequalify for capacity payments from 1 July 2025 onwards.

However, this may in any case be impractical as the T-4 auction for CY22/23 has already been held, and the derating factors have been set for the T-4 auction for CY23/24, which is imminent. Therefore, the derating factors for the period up until 1st

[16] For example, where a generator believes that it consistently out-performs the availability performance of its class, it is not permitted to assume a higher derating factor.

October 2024 are already set and it would be extremely disruptive to alter them. Accordingly, the earliest practicable implementation date is 1st October 2024.

There is therefore a strong argument that the additional derating factors should apply from 1st October 2024, as it is the earliest practicable date, even though run-hour restrictions may in practical terms actually have kicked in earlier as plant positions itself during a pre-qualification period prior to 1st July 2025.

Deferring implementation of Option 1 to 1st October 2025 is not an option that should be contemplated in our view. Instead, the following alternative could be considered:

1. Reduce capacity year 2024/25 to 9 months (ending 30th June 2025)
2. Apply Option 1 to subsequent and future auctions, beginning with capacity year 2025/26 (beginning 1st July 2025 and ending 30tth September 2026)
3. Focus on maximising the lead time of the 2025/26 T-4 auction, given the volume of new capacity required to replace the de-rated capacity of limited run-hour plant.

Should the Long Stop Date be reduced from 18 months to (for example) 12 months or 6 months?

<u>Energia Response:</u>

Energia does not believe that the Long Stop Date (LSD) should be reduced for new entry below 18 months, including for the following reasons:

1. Generation in Ireland is required to run on dual fuels. This requires additional equipment and also commissioning time;
2. Commissioning on to the Irish grid is much more difficult than in GB. This is because of the impact one generator has in relation to system security and has to be managed by the system operator; and
3. Risks in relation to longer lead times following the Coronavirus.

We do however agree that the system is heading into a period of significantly increased uncertainty due to (inter alia):

1. The requirement for new entry and the associated risks of delays.
2. The progressive reduction of excess capacity which the system had been able to rely on for several years. This excess has resulted in very low levels of utilisation of marginal generation plant and other capacity resources, so their true performance has not yet been properly tested.
3. That resources such as DSUs are largely untested, due to the over-capacity situation that has existed to date. It is unclear what the appetite for DSUs to participate will be when they are being dispatched for substantially more hours (perhaps 400 hours or more) as part of a balanced capacity portfolio.
4. The impact of further run hour limitations and including the potential for a “cliff-edge” effect if limited run-hour plant is fully utilised.

Rather than reducing the Long Stop Date, we believe that there are other measures which should be adopted in recognition of this period of elevated risk, specifically:

1. Setting appropriate derating factors for run-hour limited plant, so its contribution to CRM is not over-stated (which would result in other needed resources not being procured);
2. Procuring additional volumes in earlier or additional auctions;
3. Reducing the amount of capacity withheld from T-4 auctions. Significant withholding at T-4 increases the quantity of capacity to be acquired from resources which can be mobilised in a short timescale in (for example) T-1 or T-2 auctions. As these resources are limited, the potential for sufficient quantities to be procured to address the combination of "withheld" quantities, potential underperformance of untested capacity providers and temporary replacement of new plant which may be delayed[17], is questionable; and
4. Carrying out reviews of the overall risks associated with the future capacity portfolio and taking mitigating actions as appropriate. Such reviews would logically:
    - follow each auction (when the outcome is known including the proportion or new, untested or otherwise "at risk" resources), or
    - in the event of other significant changes in outlook, such as re-forecast of demand, known factors relating to progress of new capacity, general availability patterns, or demonstrated performance of new/largely untested resources (such as DSUs).

[17] Note this risk applies to any significant delay in the delivery of new plant; it need not be delayed to the LSD.