EP UK Investments

A member of the EPH Group

Introduction of TEG Activation Compensation Payment v2

Mods Meeting 126 – December 2024

Modification Background

- This modification was originally presented at Mods Committee meeting 125 in October.
- This modification proposes introducing a compensation payment for market-based generation which is available but not dispatched during periods where Temporary Emergency Generation (**TEG**) has been dispatched.
- The compensation payment received by units will be based on the imbalance price during each period when TEG is activated multiplied by the volume of available generation which has not been dispatched for each unit.

Updated Legal Drafting

- Following comments received by members, the legal drafting for this modification proposal has been updated:

F.23.2 Calculation of TEG Activation Compensation Payments

F.23.2.1 The Market Operator shall calculate the TEG Activation Compensation Payment or Charge ($CTEGAC_{u\gamma}$) for each Generator Unit, u, during each Temporary Emergency Generation Activation Period, k, as follows:

$$CTEGAC_{u\gamma} = \sum_{\gamma \in k} (Max(PIMB_{\gamma} - PINC_{u1\gamma}, 0) \times Max(0, qAA_{u\gamma} - QM_{u\gamma})$$

Where:

(a) $PIMB_{\gamma}$ is the Imbalance Settlement Price in Imbalance Settlement Period, γ, calculated in accordance with Chapter E (Imbalance Pricing);
(b) $qAA_{u\gamma}$ is the Actual Availability Quantity for Generator Unit, u, in Imbalance Settlement Period, γ; and
(c) $QM_{u\gamma}$ is the Metred Quantity for Generator Unit, u, in Imbalance Settlement Period, γ.
(d) $PINC_{u1\gamma}$ is the incremental price for the first price quantity pair for unit, u, in Imbalance Settlement Period, γ.

A MAX term has been introduced to ensure that the TEG compensation payment cannot go negative if a unit's theoretical costs exceed the Imbalance Price.

PINC has been introduced as an approximation of theoretical costs which would be incurred by a unit if it was dispatched, this is to reduce the risk of non-dispatched units ending up in a better position than dispatched units.

TEG Dispatch Conditions

- This modification is consistent with the principles and rules of TEG which state that TEG should not be dispatched until all market-based measures have been exhausted.

- It was stated at Mods Committee 125 that TEG would only be dispatched as a last resort, when the only other option available was load-shedding of demand. This is not supported by either the Balancing Market Principles Statement or the CRU's Risk Preparedness Plan.

- The CRU's Risk Preparedness Plan states that "*non-market measures may be dispatched*" while the system is in a 'Normal' state following the issuing of a system market notice.

- The Balancing Market Principles Statement states that "*TEG units are only dispatched once a Margin Warning has been issued, and where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation".*

- This language is ambiguous and would facilitate the dispatch of TEG even when the system is in 'normal' conditions. The only prerequisite to dispatch of TEG is the issuance of a Margin Warning.

Concerns around precedent for other constraints

- A participant expressed concerns that this modification could set a precedent for other units to claim compensation where constraints result in dispatch down (e.g., such as where wind is dispatched down to facilitate the Northern Irish minimum three conventional unit constraint).

- EP is confident that this modification is fundamentally different as it relates to TEG which is procured and subsidised by the TSO outside of existing procurement mechanisms available to SEM participants.

- Additionally, while constraints resulting in wind dispatch down should be addressed as a matter of urgency, EP notes that constraints such as the minimum conventional units and SNSP limitations have been in place for a significant number of years.

- The procurement of TEG in place of network reinforcement or procurement of capacity through the competitive Capacity Remuneration Mechanism did not have a historical precedent in the SEM and therefore would not have been factored into a business case by a prudent investor.

- It is further noted that this modification would be applicable to wind units which are available but not dispatched when TEG units are dispatched.

Concerns around unintended incentives

- A participant expressed concern that this modification could result in an unintended incentive for generators to locate behind a constraint in order to benefit from this modification.
- EP is satisfied that this risk is negligible given that a generator behind a constraint would only receive payments through this modification in rare instances when TEG is dispatched.
- Conversely, a generator located behind such a constraint would be likely to suffer as a result of being unable to reliably export its power to the market.
- It is also noted that the Capacity Market includes maximum locational capacity constraint areas which would likely prevent a generator being able to locate in such an area.
- Based on this balance of risk between the downside of being behind a constraint and the upside obtained through fringe cases, EP is not concerned with this risk.

Cost for consumer

- Participants expressed concerns around the potential cost impact of this modification. Based on this, we carried out analysis on potential cost of implementing the measure.

- As TEG has never been dispatched to respond to Security of Supply, we used historic data and examined a day which experienced a System Alert and had low margins: 12 June 2023, specifically between 12.30 and 18.30.

- Approximate values have been calculated for headroom (not including interconnector volumes) during each imbalance period within this timeframe and multiplied by the imbalance price.

Period	Approx. Headroom (MW)	PIMB (€/MW)	Cost (€)
12:30	874.2	403.68	352,903.8
13:00	878.9	356.66	313,480.4
13:30	916.1	227.5	208,401.4
14:00	948.1	225	213,326.3
14:30	974.8	225	219,326.3
15:00	1007.2	254.73	256,572.5
15:30	993.8	225	223,593.8
16:00	955.0	269.77	257,634.8
16:30	954.2	495.5	472,830.9
17:00	920.3	408.89	376,287.8
17:30	880.1	394.64	347,329.2
18:00	942.1	387.47	365,041.9
18:30	1036.9	380.85	394,884.3
Total			**4,001,613.4**

This table provides a good illustration of the value of the potential impact of this modification in an extreme case (i.e., TEG active for six hours), as well as impact on a per imbalance settlement period basis. Additionally, this calculation does not take account of the deduction of unit costs during each imbalance settlement period, so in actuality the impact would be lower.

Cost for consumer

- The cost of dispatching TEG is considerably more significant due to the European Commission's Guidelines on State Aid for Climate, Environmental Protection, and Energy 2022 which state that during periods where strategic reserves, or any other measure for resource adequacy where capacity is held outside the market, "*imbalances in the market are to be settled at least at VOLL or at a higher value than the intraday technical price limit, whichever is higher".*

- Applying this requirement to the same period on 12 June 2023:

Period	Imbalance Volume (MW)	VOLL (€/MW)	Cost (€)
12:30	865.7	18,123	15,689,081.1
13:00	903.3	18,123	16,371,110.0
13:30	846.1	18,123	15,334,172.4
14:00	754.1	18,123	13,666,252.3
14:30	750.4	18,123	13,599,801.3
15:00	747.8	18,123	13,552,681.5
15:30	744.8	18,123	13,498,312.5
16:00	780.1	18,123	14,138,356.4
16:30	866.4	18,123	15,701,767.2
17:00	1147.1	18,123	20,788,289.2
17:30	1025.3	18,123	18,581,209.9
18:00	874.9	18,123	15,854,906.6
18:30	950.2	18,123	17,219,568.5
Total			**203,995,508.5**

This illustrates that relying on the dispatch of TEG is far more expensive for the consumer based on the requirement to apply VOLL pricing during periods when TEG is dispatched.

This is in addition to the > €1bn which the consumer has already incurred through TEG procurement.

Impact on systems

- A participant expressed concern that this modification would require system changes at significant cost and requiring significant development time relative to the benefit achieved through its implementation. This concern is based on the expectation that TEG contracts will end and will not be renewed post-2026.

- EP believe there is a risk that TEG is either extended or further TEG is procured post-2026. The TSOs' Generation Capacity Statement for 2023 – 2032 identified an adequacy deficit of over 1GW on an all-island basis in 2026. EP notes that other '*temporary*' measures such as locational constraints in the Capacity Market have been in place for significantly longer than originally envisioned.

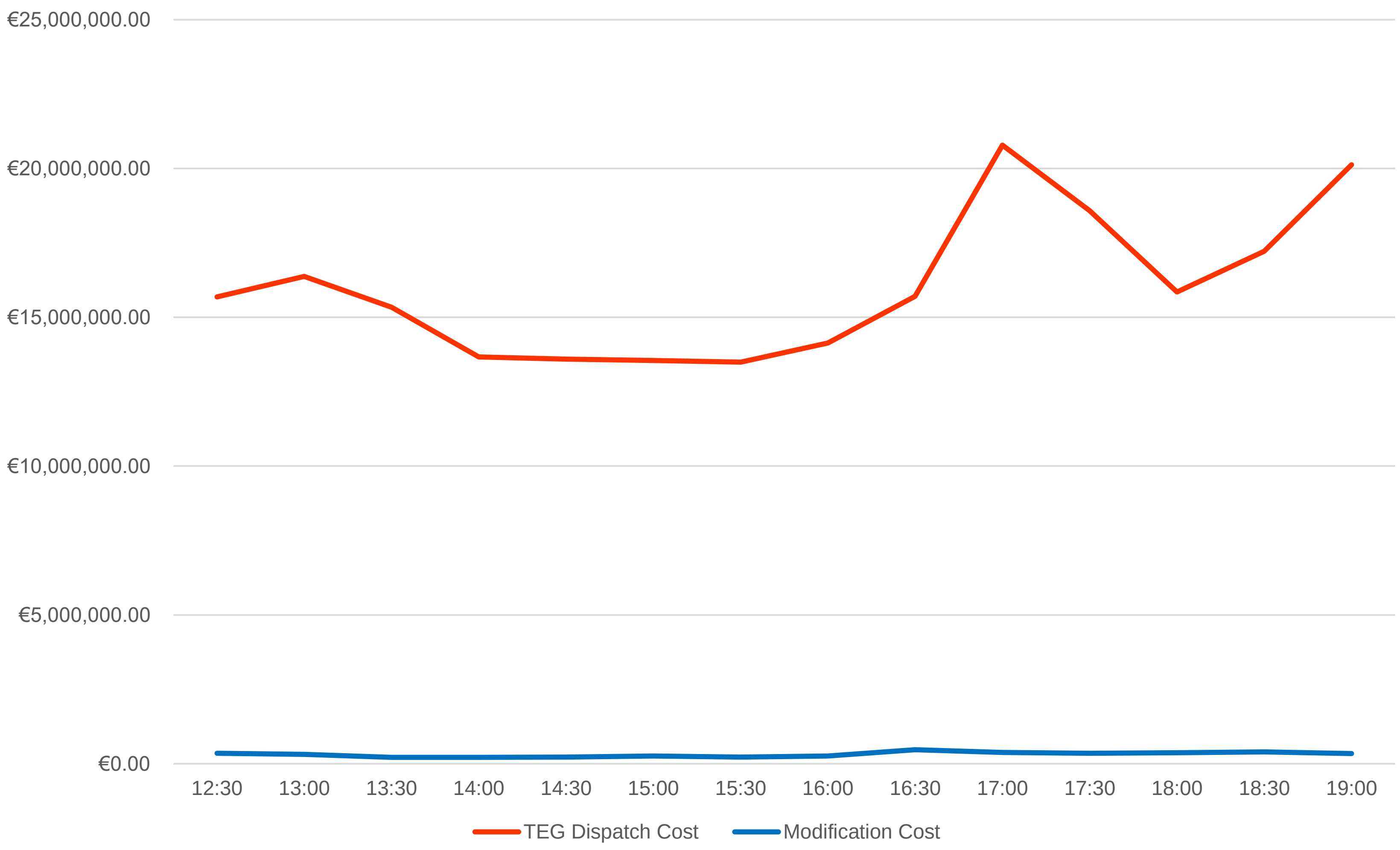
- In this context, EP believe it would be prudent to progress this modification so that it will be in place for the current and any future tranche of TEG. Given the potential lead times for this amendment, it is advisable to begin work on this development so that it will be in place as soon as possible.

Conclusion

- EP believes that this modification is necessary to protect market participants from discrimination, support investor confidence in the SEM, and to ensure that the electricity market is operated in a fair and transparent manner.

- This modification also supports consumers by protecting and fostering the competitive markets which deliver better outcomes and disincentivising further reliance on more expensive TEG.

Comparison of modification cost vs. TEG dispatch cost – 12 June 2023



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