Single Electricity Market

FINAL RECOMMENDATION REPORT

MOD_07_24 INTRODUCTION TO TEG ACTIVATION COMPENSATION PAYMENT

9 JANUARY 2025

Document History

Version	Date	Author	Comment
1.0	9 January 2025	Modifications Committee Secretariat	Issued to Modifications Committee for review and approval
2.0	16 January 2025	Modifications Committee Secretariat	Issued to Regulatory Authorities for final decision

Reference Documents

Document Name
Trading and Settlement Code
Mod_07_24 Introduction to TEG Activation Compensation Payment Presentation
Mod_07_24 Introduction to TEG Activation Compensation Payment v2 Presentation v2

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1. MODIFICATIONS COMMITTEE RECOMMENDATION

RECOMMENDED FOR REJECTION – MAJORITY VOTE

Recommended for Rejection by Majority Vote		
Stacy Feldmann (Chair)	Generator Member	Reject
Cormac Daly	DSU Member	Reject
Harry Molloy	Generator Member	Approve
Andrew Kelly	Generator Member	Reject
David Caldwell	Supplier Member	Reject
David Morrow	Generator Member	Reject
Niamh Trant	Supplier Alternate	Reject
Andrew Burke	Renewable Generator Member	Reject
David Hargadon	Flexible Participant Member	Reject
Colm Oireachtaigh	Supplier Member	Reject
Bryan Hennessy	Supplier Member	Reject
Eoin Murphy	Assetless Member	Reject

2. BACKGROUND

This Modification Proposal was raised by EPUKI and received by the Secretariat on 3rd October 2024. The Proposal was raised and discussed at Meeting 125 and voted on at Meeting 126 on Thursday, 5th December 2024.

This Modification proposes to introduce a compensation payment for instances where Temporary Emergency Generation (**TEG**) is dispatched ahead of market generation. This payment will be based on the imbalance price during the period of TEG dispatch multiplied by the available volume of market-based generation which has not been dispatched.

This Modification has been amended to subtract an approximation of theoretical unit costs from any compensation payment received by a unit. This aims to reduce the risk of units which have not been dispatched receiving a compensation payment and ultimately ending up in a better financial position than units which were dispatched and responded to meet demand.

3. PURPOSE OF PROPOSED MODIFICATION

3A.) JUSTIFICATION OF MODIFICATION

Since 2021, the CRU has instructed EirGrid to procure 653MW of Temporary Emergency Generation (**TEG**) in the Republic of Ireland (**ROI**). In addition to this new generation, the CRU has approved the extension of 820MW of existing generation which was scheduled to close in 2024 through out-of-market arrangements. This generation was not procured through existing market mechanisms, designed to promote competition in the provision of generation adequacy.

The Transmission System Operators (**TSOs**) Balancing Market Principles Statement (**BMPS**) outlines how TEG will be operated in the market. Specifically, the BMPS notes that TEG "*will only be made available for dispatch when security of supply risk has been identified and where is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation"* [emphasis added]. This modification refers specifically to ensuring that all 'market-based measures' have been exhausted prior to the dispatch of TEG units, as per relevant EU legislation. This modification proposes that where TEG is dispatched ahead of market-based generation, which is declared available, the market-based generation will be compensated.

The procurement and potential dispatch of TEG prior to available market-measure being exhausted represents a risk to the business case for generation in the Single Electricity Market (**SEM**). This risk applies to both existing generation and new generation which may have developed a business case based on scarcity on the Irish system. The procurement of TEG represents a risk to this business case whereby scarcity events may be addressed through generation which has not been procured through established SEM market mechanisms.

Failure to account for this risk in the Trading and Settlement Code undermines the business case for generation in the SEM, as well as the regulatory stability associated with the SEM. The possibility for the TSO to dispatch TEG procured outside the SEM represents a disadvantage to SEM generation which would otherwise be required to respond to scarcity events. Generation in Northern Ireland is disadvantaged in particular, as TEG procurement was exclusive to ROI. This modification intends to ensure that there is minimum distortion of the energy market, and that there exists a level-playing field between generation on the island of Ireland to avoid discrimination between regulatory jurisdictions.

EPUKI believes that this Modification is consistent with the objectives and principles of the SEM and the Trading and Settlement Code (**TSC**). It is noted that the section A.2.1.1 of the TSC states that "*this Code governs the trading and settlement arrangements for the Balancing Market".* While TEG is intended to be reserved for emergency applications only, any dispatch of TEG in place of TSC recognised generation would be external to and contradictory to this clause.

This Modification is also aligned with EU Regulation 2019/943 Article 12 (1) which requires the dispatch of generation to be market-based, with the exception of the application of Priority Dispatch. 2019/943 Article 13 sets out the rules around re-dispatching of generation and notes that redispatch should only be sourced using market-based mechanisms except where "*no market-based alternative is available*" and "*all available market-based resources have been used".* This is clearly aligned with the principle of this modification proposal in that all available SEM generation would need to be exhausted before TEG could be activated.

EPUKI does not expect this Modification to have a financial impact on consumers, as proper application of the rules as per the BMPS and relevant EU legislation governing TEG should mean that all available market generation has been dispatched before TEG is activated, thus resulting in no compensation payment.

3B.) IMPACT OF NOT IMPLEMENTING A SOLUTION

Failure to implement this Modification would represent a failure to protect SEM participants from loss of revenue as a result of externally procured generation with external subsidisation. This undermines the business case for both existing and new generation.

Additionally, the risk of TEG units being dispatched in place of available market generation would be contradictory to market rules around discrimination and fairness.

3C.) IMPACT ON CODE OBJECTIVES

This proposal furthers the following objectives, as set out under Section A.2.1.4 of the Trading and Settlement Code:

(b) to facilitate the efficient, economic and coordinated operation, administration and development of the Single Electricity Market in a financially secure manner;
(c) to facilitate the participation of electricity undertakings engaged in the generation, supply or sale of electricity in the trading arrangements under the Single Electricity Market;
(d) to promote competition in the Single Electricity Market;
(e) to provide transparency in the operation of the Single Electricity Market;
(f) to ensure no undue discrimination between persons who are parties to the Code; and
(g) to promote the short-term and long-term interests of consumers of electricity on the island of Ireland with respect to price, quality, reliability, and security of supply of electricity.

4. WORKING GROUP AND/OR CONSULTATION

N/A

5. IMPACT ON SYSTEMS AND RESOURCES

N/A

6. IMPACT ON OTHER CODES/DOCUMENTS

N/A

7. MODIFICATION COMMITTEE VIEWS

MODIFICATIONS COMMITTEE MEETING 125 – 24TH OCTOBER 2024

The Proposer delivered a presentation on this Modification Proposal explaining that it was raised to minimize market distortion and to ensure the TEG is implemented correctly. The Proposer explained the justification of the Modification. It was advised that comments were received before the meeting with regards to the compensation to units that would not have been dispatched and would be compensated more than units dispatched on the day which would see their costs deducted from the PIMB. The Proposer explained that the advice was fair therefore the legal drafting would need to be updated, and a deferral may be required for this Modification Proposal.

The Chair asked if the likelihood of this scenario happening had been modelled, because all the information received on TEG stated that units were only going to be dispatched in specific circumstances of warning levels and after all non-TEG units had been dispatched. The Proposer admitted that no modelling had been carried out but noted that the current constraints, both in Dublin and nationwide were getting worse and the procurement of non-market generation of greater magnitude of the North-South Tie-Line, was unfair to units in NI in particular and it could lead to an incentive to do it again in the future instead of carrying out the necessary reinforcements, while units in NI were being discriminated if they were not overlooked to respond to a constraint Incentives would be removed if constraints were always to be addressed via localized emergency generation.

It was noted by Members that scarcity events do no longer occur in the market and Reliability Options would cause penalties to be applied before scarcity events. A Supplier Member queried the need of this modification because TEG are temporary and asked what measures were in place when Ballylumford was contracted around 2015 in the old Sem market.

Support was given to a suggestion that a single document outlining how TEGs are run and operated should be made available. Further questions were raised to the Proposer on how was demand response accounted for in this Modification and how would Start Up Costs be considered.

SO Member stated that the rules for the circumstances that would lead to the dispatch of TEG are consolidated in the Balancing Market Principle Statement (BMPS) and the Risk Preparedness Plan 2023 (RPP) and both states that the use of TEG would be a last resort before shedding customer load. These have been widely discussed over three MOUG presentations and the process is subject to the dispatch audit.

A Supplier Member question if this type of compensation could lead the way to other claims for example from Wind units in NI where the constraints always require at least three Thermal Generators dispatched on. This would create the potential for more compensations paid by the consumers for a lot of inefficiencies with a large impact on Imperfections. The Proposer replied that wind units are not comparable, and that procurement of emergency generation in small scale where localized issues are identified, may be understandable, but in this case between new tendered generation and retained generation the amount is almost double the size of the North-South Tie-Line and it disincentivizes the grid development. Also, the dispatch of such generation could happen in moments of crisis where errors may occur. The Proposer believe that the Modification attenuates the impacts of error and remove the incentive to continue procurement of emergency generation in the long term as a permanent solution.

A Generator Alternate reiterated the concerns that this Modification could have a significant cost for the consumer for no benefit and it doesn't seem to be an appropriate measure to push necessary system reinforcements that are already in the planning stage. MO Member also stated that, although the proposer had considered this Modification to have no cost impacts, system changes are necessary for a scenario that doesn't seem to be likely to happen. Also, consideration needs to be given to the implementation timeline of such changes compared to the lifespan of TEG which are contracted only until 2026 with a further 2 years extension possible.

The Chair concluded that this Modification puts the Committee in a difficult position because there is no impact of the likelihood of it happening or the potential costs. Assetless Member reiterated his concerns that this Modification would incentivize Generator being built behind a constraint so that they could get the benefit of a compensation based on availability alone without providing no relief to the potential security of supply event. A Supplier Member agreed that this seems to provide a blanket guarantee to any available Generator and that the procurement of TEG should not be regarded as an obstacle for NI units and the limits on North-South exports existed well before and would be there even without TEG. Also, consideration should be given to the large costs of awarding capacity in such circumstances.

The Proposer reiterated that in their view the presence of TEG undermines the development of the grid in the long term. It was advised that the Proposer should submit a version 2 of this Proposal including an impact assessment on cost on imperfections charges and system changes. Proposer asked to provide modelling of eventuality of implementation of this Proposal.

MODIFICATIONS COMMITTEE MEETING 126 – 5TH DECEMBER 2024

The Proposer delivered a presentation on version 2 of this Modification Proposal. The new components that were added to the legal drafting were explained noting that Incremental Price (PINC)1 was introduced to reflect an approximate cost and mitigate the instance of non-dispatched units ending up in a better position than dispatched units. The Proposer recognized that PINC1 was not a perfect reflection of cost but more of an approximation.

An overview of the comments raised at Meeting 125 was given. The Proposer felt that the Transmission System Operator (TSO) statement noting Temporary Emergency Generation (TEG) units were only dispatched as a last resort wasn't clearly reflected in BMPS and it appears that TEG units could be dispatched whilst the system is in a normal state. The concern around this Proposal setting a precedent for other scenarios was also addressed by the Proposer whose view was that other scenarios were not comparable and while other constraints were well known, the introduction of TEGs would not have been foreseen and would not have been part of business plan forecasting.

The Proposer continued that there was no reason why this Proposal could not be applied to wind units and these units should also receive compensation if constrained down while TEG are dispatched.

A supporting slide regarding cost analysis was presented and it was advised that the total cost estimated for the Proposal for one historic day, the latest available date with an all-island warning, would have been approximately €4 million. The Proposer recognized that this figure was significant, but incentives must be given not to use TEG and the cost of the TEG themselves was comparatively much higher around €15 million.

RA Member asked if in the scenario presented, the margin of approximately 1,000 MW would receive compensation even if only one MW of TEG were to be dispatched. The Proposer agreed that would be the case. RA Member then intervened mentioning that the TEG costs in the presentation was overestimated because TEG is a temporary measure under EU Regulation 2019/941 on risk-preparedness in the electricity sector and the price would not automatically go to Value of Lost Load (VOLL) in these circumstances. The Proposer debated that this was not their interpretation of the Regulation and would seek to have confirmation of that.

The Chair questioned if there was more clarity on TEG under Risk Preparedness would there be a need for this Proposal? The Proposer confirmed that this clarity would improve things greatly but would need to examine carefully any change proposed and what protections would be put in place. The Chair appreciated that a lot of work went into drafting this Proposal and the cost analysis but felt that it was raised based on a “just in case” scenario at high cost to the consumer and did not provide good governance.

A Supplier Member commented that the available capacity is not always an indication of what the TSO can use in practice as the Tie-Line constraint between NI and ROI prevent that making the potential use of TEG unavoidable in certain potential circumstances. The Proposer noted that they believed this was a critical Modification Proposal and it highlighted the need to ensure that Market based generators are not disadvantaged over non-market-based ones.

There was general agreement from the Committee that further clarity and transparency on the criteria for the dispatch of TEG would be welcomed, but many voiced concerns over the implementation of this Modification and the added layer of complication that the TSO would have to deal with in an emergency scenario and that the consumer would have the burden of an additional cost for no added value.

TSO Alternate made a number of points starting with the fact that the TSO actions are audited and therefore any error would be included in the audit outcome; also this Modification introduces the possibility that units receive double payments in Imperfections and allow compensations to all generators even if they would not be able to provide the MW dispatched to TEG; for example a battery would have a limited length of output and in the example given in the presentation would not be able to sustain 6 hours of generation. Details on the criteria for the use of TEG contained in table 2 of page 44 of the Risk Preparedness Plan (RPP) were also shared and explained. These were more specific than previously cited sections of the document and would seem to alleviate some of the concerns around transparency. The Proposer asked for more time to review them and consider them.

Several Members expressed that they were satisfied to proceed to a vote on the Proposal.

MO Member then advised that the Risk Preparedness Plan document is currently under review in RA led Workshops and encouraged attendees to raise any questions or requests for more details in those fora. The current TSO procedures are taken directly from the RPP so any change there would be reflected in the TSO procedures.

8. PROPOSED LEGAL DRAFTING

As per Appendix 1.

9. LEGAL REVIEW

N/A

10. IMPLEMENTATION TIMESCALE

The Committee has voted recommending to reject this Modification.

APPENDIX 1: MOD_07_24 INTRODUCTION TO TEG ACTIVATION COMPENSATION PAYMENT V2

Proposer *(Company)*	**Date of receipt** *(assigned by Secretariat)*	**Type of Proposal** *(delete as appropriate)*	**Modification Proposal ID** *(assigned by Secretariat)*
EP UK investments	**20th November 2024**	Standard	**Mod_07_24 v2**

Contact Details for Modification Proposal Originator

Name	**Telephone number**	**Email address**
Harry Molloy		h.molloy@tynaghenergy.ie

Modification Proposal Title

Introduction of TEG Activation Compensation Payments v2

Documents affected *(delete as appropriate)*	**Section(s) Affected**	**Version number of T&SC or Agreed Procedure used in Drafting**
T&SC Part B **Glossary Part B**	**F.23**	**V28.0**

Explanation of Proposed Change

(mandatory by originator)

This modification proposes to introduce a compensation payment for instances where Temporary Emergency Generation (**TEG**) is dispatched ahead of market generation. This payment will be based on the imbalance price during the period of TEG dispatch multiplied by the available volume of market based generation which has not been dispatched.

This modification has been amended to subtract an approximation of theoretical unit costs from any compensation payment received by a unit. This aims to reduce the risk of units which have not been dispatched receiving a compensation payment and ultimately ending up in a better financial position than units which were dispatched and responded to meet demand.

Legal Drafting Change

*(Clearly show proposed code change using **tracked** changes, if proposer fails to identify changes, please indicate best estimate of potential changes)*

This modification would require the introduction of new terminology to the glossary:

Temporary Emergency Generation means generation procured to mitigate an electricity crisis under the Risk Preparedness Regulation EU Regulation 2019/941.

Temporary Emergency Generation Activation Period means a period during which Temporary Emergency Generation has been dispatched for non-test purposes as defined in Section F.23.1.

TEG Activation Compensation Payment a payment made to a Generator Unit which is available to provide electricity but is not dispatched during periods when Temporary Emergency Generation has been dispatched for non-test purposes.

The key change in this modification is the introduction of a new payment to Generators. This payment will be based on the imbalance price and will be received by generators which have not been dispatched during periods where TEG has been dispatched for non-test purposes. This amendment will be included in a new subsection of the Code:

F.23 Temporary Emergency Generation Activation Compensation Payments

F.23.1 Determination of Temporary Emergency Generation Activation Period

F.23.1 The Market Operator shall determine the start of each Temporary Emergency Generation Activation Period as the start of the Imbalance Settlement Period, γ, during which Temporary Emergency Generation is dispatched to a non-zero MW export, and is not Under Test.

F.23.2 The Market Operator shall determine the end of each Temporary Emergency Generation Activation Period as the end of the Imbalance Settlement Period, γ, during which the value of dispatch for all Temporary Emergency Generation falls to zero.

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.

This calculation has been updated to include a PINC term to remove the incremental price for a unit from the revenue received through the compensation mechanism. This amendment has been made in order to reduce the likelihood of units which were not dispatched ending up in a better financial position than units which were dispatched.

The first PINC has been chosen as an approximation for a unit's theoretical costs. It is difficult to provide a more accurate reflection of costs given that this is associated with theoretical dispatch only and costs for each unit would vary based on incremental costs, start-up costs, and no-load costs.

F.23.3 Payments for TEG Activation

F.23.3.1 The total TEG Activation Compensation Payment ($CTEGAC_{ud}$) made for each Generation Unit, u, for each Settlement Day, d, shall be calculated by the Market Operator as follows:

$$CTEGAC_{ud} = \sum_{\gamma \in d} CTEGAC_{u\gamma}$$

Where:

(a) $CTEGAC_{u\gamma}$ is the TEG Activation Compensation Payment or Charge in Imbalance Settlement Period, γ, calculated in accordance with Section F.23.2; and
(b) $\sum \gamma \text{ in } d$ is the summation over all Imbalance Settlement Periods γ in Settlement Day d.

Payments associated with TEG Activation will then be passed through to the Total Daily Amounts Calculation for Generator Units.

The Total Daily Amounts ($CDAY_{ud}$) made for each Generator Unit u for each Settlement Day d shall be calculated by the Market Operator as follows:

$$CDAY_{ud} = CIMB_{ud} + CPREMIUM_{ud} + CDISCOUNT_{ud} + CAOOPO_{ud} + CABBPO_{ud} + CCURL_{ud} + CUNIMB_{ud} + CII_{ud} + CTEST_{ud} + CTEGAC_{ud}$$

where:

$CIMB_{ud}$ is the total Imbalance Component Payment or Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.2;

$CPREMIUM_{ud}$ is the total Premium Component Payment for Generator Unit u for Settlement Day d calculated in accordance with section G.4.3;

$CDISCOUNT_{ud}$ is the total Discount Component Payment for Generator Unit u for Settlement Day d calculated in accordance with section G.4.4;

$CAOOPO_{ud}$ is the total Offer Price Only Accepted Offer Payment or Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.5;

$CABBPO_{ud}$ is the total Bid Price Only Accepted Bid Payment or Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.6;

$CCURL_{ud}$ is the total Curtailment Payment or Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.7;

$CUNIMB_{ud}$ is the total Uninstructed Imbalance Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.8;

CII_{ud} is the total Information Imbalance Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.9; and

$CTEST_{ud}$ is the total Testing Charge for Generator Unit u for Settlement Day d calculated in accordance with section G.4.10.

$CTEGAC_{ud}$ is the total TEG Activation Compensation Payment or Charge for Generator Unit u for Settlement Day d calculated in accordance with section F.23.3.

Modification Proposal Justification

(Clearly state the reason for the Modification)

Since 2021, the CRU has instructed EirGrid to procure 653MW of Temporary Emergency Generation (**TEG**) in the Republic of Ireland (**ROI**). In addition to this new generation, the CRU has approved the extension of 820MW of existing generation which was scheduled to close in 2024 through out-of-market arrangements. This generation was not procured through existing market mechanisms, designed to promote competition in the provision of generation adequacy.

The Transmission System Operators (**TSOs**) Balancing Market Principles Statement (**BMPS**) outlines how TEG will be operated in the market. Specifically, the BMPS notes that TEG "*will only be made available for dispatch when security of supply risk has been identified and where is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation*" [emphasis added]. This modification refers specifically to ensuring that all 'market-based measures' have been exhausted prior to the dispatch of TEG units, as per relevant EU legislation. This modification proposes that where TEG is dispatched ahead of market-based generation, which is declared available, the market-based generation will be compensated.

The procurement and potential dispatch of TEG prior to available market-measure being exhausted represents a risk to the business case for generation in the Single Electricity Market (**SEM**). This risk applies to both existing generation and new generation which may have developed a business case based on scarcity on the Irish system. The procurement of TEG represents a risk to this business case whereby scarcity events may be addressed through generation which has not been procured through established SEM market mechanisms.

Failure to account for this risk in the Trading and Settlement Code undermines the business case for generation in the SEM, as well as the regulatory stability associated with the SEM. The possibility for the TSO to dispatch TEG procured outside the SEM represents a disadvantage to SEM generation which would otherwise be required to respond to scarcity events. Generation in Northern Ireland is disadvantaged in particular, as TEG procurement was exclusive to ROI. This modification intends to ensure that there is minimum distortion of the energy market, and that there exists a level-playing field between generation on the island of Ireland to avoid discrimination between regulatory jurisdictions.

EPUKI believes that this modification is consistent with the objectives and principles of the SEM and the Trading and Settlement Code (**TSC**). It is noted that the section A.2.1.1 of the TSC states that "*this Code governs the trading and settlement arrangements for the Balancing Market".* While TEG is intended to be reserved for emergency applications only, any dispatch of TEG in place of TSC recognised generation would be external to and contradictory to this clause.

This modification is also aligned with EU Regulation 2019/943 Article 12 (1) which requires the dispatch of generation to be market-based, with the exception of the application of Priority Dispatch. 2019/943 Article 13 sets out the rules around re-dispatching of generation and notes that redispatch should only be sourced using market-based mechanisms except where "*no market-based alternative is available*" and "*all available market-based resources have been used".* This is clearly aligned with the principle of this modification proposal in that all available SEM generation would need to be exhausted before TEG could be activated.

EPUKI does not expect this modification to have a financial impact on consumers, as proper application of the rules as per the BMPS and relevant EU legislation governing TEG should mean that all available market generation has been dispatched before TEG is activated, thus resulting in no compensation payment.

Code Objectives Furthered

(State the Code Objectives the Proposal furthers, see Section 1.3 of Part A and/or Section A.2.1.4 of Part B of the T&SC for Code Objectives)

This proposal furthers the following objectives, as set out under Section A.2.1.4 of the Trading and Settlement Code:

(h) to facilitate the efficient, economic and coordinated operation, administration and development of the Single Electricity Market in a financially secure manner;
(i) to facilitate the participation of electricity undertakings engaged in the generation, supply or sale of electricity in the trading arrangements under the Single Electricity Market;
(j) to promote competition in the Single Electricity Market;
(k) to provide transparency in the operation of the Single Electricity Market;
(l) to ensure no undue discrimination between persons who are parties to the Code; and
(m) to promote the short-term and long-term interests of consumers of electricity on the island of Ireland with respect to price, quality, reliability, and security of supply of electricity.

Implication of not implementing the Modification Proposal

(State the possible outcomes should the Modification Proposal not be implemented)

Failure to implement this modification would represent a failure to protect SEM participants from loss of revenue as a result of externally procured generation with external subsidisation. This undermines the business case for both existing and new generation. Additionally, the risk of TEG units being dispatched in place of available market generation would be contradictory to market rules around discrimination and fairness.	
Working Group *(State if Working Group considered necessary to develop proposal)*	**Impacts** *(Indicate the impacts on systems, resources, processes and/or procedures; also indicate impacts on any other Market Code such as Capacity Market Code, Grid Code, Exchange Rules etc.)*
Please return this form to Secretariat by email to balancingmodifications@sem-o.com	