Imperfections Charges Forecast

Tariff Year 2026/27

17th June 2026

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Revision History		
Revision	Date	Description
v1.0	29/05/26	Issued to RAs
V2.0	17/06/26	Revised Interconnection NTC Restriction Revenue Requirement

Abbreviations and Acronyms

Acronym (abbreviation)	Term
AGU	Aggregated Generator Unit
AIRAA	All Island Resource Adequacy Assessment
BETTA	British Electricity Trading and Transmission Arrangements
BMPCOP	Balancing Market Principles Code of Practice
CCGT	Combined Cycle Gas Turbine
CEP	Clean Energy Package
COD	Commercial Offer Data
CRU	Commission for Regulation of Utilities
DBC	Dispatch Balancing Costs
DSU	Demand Side Unit
EWIC	East West Interconnector
GB	Great Britain
GTC	Gas Transportation Charges
GPI	Generator Performance Incentive
HILP	High Impact Low Probability
MW	Megawatt
MWh	Megawatt hour
GWh	Gigawatt hour
NPDR	Non-Priority Dispatch Renewables
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OSC	Other System Charges
PNs	Physical Notifications
RA	Regulatory Authority
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
SDP	Scheduling & Dispatch Programme
SEM	Single Electricity Market
SEMC	Single Electricity Market Committee
SEMO	Single Electricity Market Operator
SNSP	System Non-Synchronous Penetration
T&SC	Trading and Settlement Code

TCG	Transmission Constraint Group
TEG	Temporary Emergency Generation
TOOT	Taking Out One at a Time
TOD	Technical Offer Data
TSOs	Transmission System Operators
UK	United Kingdom
UUC	Unconstrained Unit Commitment
UR	Utility Regulator
VOM	Variable Operation and Maintenance
MWCCF	Market Working Capital Credit Facility
MMS	Market Management System

1. Summary

EirGrid and SONI are Transmission System Operators (TSOs). In this role, the TSOs take actions to ensure the continuous supply of power and system security to customers across the system in real time. As a result, the TSOs may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions is known as Imperfections Costs. These costs are paid from the money received from suppliers through Imperfection Charges.

The purpose of this submission is to set out the TSO's' proposed values for 2026/27 Imperfections Charges which are then assessed and decided upon by the Regulatory Authorities (RAs).

1.1. What are Imperfections Charges and why is a forecast needed?

Imperfections Charges recover the total expected costs of managing the transmission system safely and securely. In operating the transmission system, the TSOs work to ensure supply of power and system security to customers across the system in real time. That means we may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions we take to keep the system balanced and secure is funded through the Imperfections Charge.

The RAs assess and the Single Electricity Market Committee (SEMC) decides on the level at which the Imperfections Charge is to be set for the upcoming Tariff Year which runs from 01 October 2026 to 30 September 2027. The Imperfections Charge parameters is set before each Tariff Year, which is used to calculate the PIMP component as per section F.12 of Trading and Settlement Code. The TSOs must submit a report to the RAs which sets out their forecast of Imperfections Charge Parameters for the upcoming Tariff Year. The estimates provided in this report are based on the best available data at the point of preparation. Both TSO's strategically employed a data freeze for the various forms of approximate input data that feeds into the PLEXOS model with the joint objective to optimize the most up to date information available for each input and meet Imperfections forecast delivery timelines. The origin and timings of specific data sources used for key input data is identified throughout this document. For the K Factor determination, the input data was taken based on the latest settlement data available up to the 9th of May 2026.

The Imperfections Charges Parameters are made up of two parts:

1. Imperfections Price (PIMP)(€/MWh)

We calculate PIMP by dividing the anticipated imperfections cost by the forecast demand. When calculating this anticipated imperfection cost, we also consider the K Factor. The K Factor considers adjustments from previous years, where imperfection costs were more or less than we expected.

2. Imperfections Charge Factor (FCIMP)

Section F.22.2.5[1] of the Trading and Settlement Code (**TSC)** provides scope to adjust the FCIMP (which by default is set to 1) in situations where the Imperfections Price is significantly less or more than we need to

[1] If the Market Operator considers that either the current rate of draw-downs being made under the Market Working Capital Credit Facility or the amount drawn-down under the Market Working Capital Credit Facility specified in a notice to Participants under F.22.2.4 is such that there is likely to be a reduction in payments to Participants under paragraph F.22.3.1, then the Market Operator shall:

recover the anticipated costs. At the time of writing this submission, we do not propose any change to the Imperfections Charge Factor for 2026/27 Tariff Year.

After we make our submission to the RAs, they assess and make a recommendation to the SEMC who decide on the above Imperfections Charge Parameters for the applicable period. The Single Electricity Market Operator (SEMO) then levies this charge on all supplier units based on their metered demand.

1.2. Anticipated Imperfections Charges Parameters for 2026/27

We calculated the anticipated Imperfections Charges Parameters, based on several assumptions and expected conditions for the 2026/27 tariff year period (01/10/2026 to 30/09/2027). The table below shows our forecast for the Imperfection Charge Parameters, with the amounts approved for last year shown alongside for reference.

	TSOs' Submission 2026/27 (€m)	RA Allowed Amount 2025/26 (€m)	Difference (€m)
Anticipated imperfections costs (€m)	810.14	606.81	203.33
K Factor (€m)	(13.22)	183.43	(196.65)
Anticipated imperfections cost less K Factor adjustment (€m)	796.92	790.24	6.68
Forecast demand (GWh)	42,160	39,650	2,510
Imperfections Price (PIMP)(€/MWh)	18.90	19.93	(1.03)
Imperfections Charge Factor (FCIMP)	1.0	1.0	0.0

Table 1 TSOs' Submission of Anticipated Imperfections Charges Parameters

The €810.14m does not include costs in relation to potential historic resettlement arising from a known defect in the SEMO Settlement Systems[2], which should they arise, would drive the under recovery of Imperfections costs.

(a) investigate an increase in the level of the Market Working Capital Credit Facility, and may make a proposal to the Regulatory Authorities under paragraph F.22.1.1;

(b) identify any other measures available to it under this Code that, solely to the extent practicable in the circumstances, the Market Operator considers reasonable to lessen the likelihood of making a reduction of payments to Participants under paragraph F.22.3.1, including, but not limited to, making a Modification Proposal, proposing revisions to the Imperfections Charge Factor under paragraph F.12.1.4 (having regard to the need of Suppliers to provide adequate notice of tariff changes to their customers) or any combination of measures which the Market Operator considers appropriate in the circumstances; and

(c) submit a report to the Regulatory Authorities outlining the outcome of its considerations under paragraphs F.22.2.5(a) and F.22.2.5(b).

[2] KIR ID 20240711-6323150 – note per the May KIR a fix of the Settlement system is scheduled for late June

1.3. Imperfections Price – Customer Impact Assessment

Suppliers pay Network Imperfections Charges to SEMO. It is at the Suppliers' decision as to how much, if any, they pass on to their customers. If the suppliers passed on the entirety of the forecast Imperfections Price (PIMP)(€/MWh) to consumers, this would reduce the monthly bill in Ireland by €0.35 and £0.23 in Northern Ireland. Table 2 below outlines the potential consumer impact of the 2026/27 TSOs' forecast costs compared to the SEM Committee's approved costs for 2025/26.

	Total Imperfections Costs (€m)	Imperfections Price (PIMP) (€/MWh)	Annual Cost for Average Energy Consumer IE (€)	Monthly Cost for Average Energy Consumer IE (€)	Annual Cost for Average Energy Consumer NI (£)	Monthly Cost for Average Energy Consumer NI (£)
2026/27 Imperfections Forecast	796.92	18.90	79.4	6.62	52.03	4.34
2025/26 RA Approved Imperfections	790.24	19.93	83.7	6.97	54.87	4.57
Difference	6.68	-1.03	-4.3	-0.35	-2.84	-0.23

Table 2 Customer Impact Assessment of the 2026/27 Imperfections Forecast Costs

1.4. Main drivers in 2026/27 anticipated Imperfections Charges Parameters

The forecasted imperfection cost for 2026/27 is €810.14m. This is an increase of €203.34m compared to the €606.81m approved by the RAs in the preceding Tariff Year.

This includes €141m for potential payments to participants under the Clean Energy Package Article 13(7), as discussed further in Section 4.3 and €56.68m[3] for payments to Interconnector participants for the historical Ex-Ante restriction of their Net Transfer Capacity as discussed further in Section 4.4.

Excluding the provision for Clean Energy Package Article 13(7) (CEP) and Interconnector Net Transfer Capacity Restrictions, we forecast a spend of €612.46m for the 2026/27 tariff year. This estimated cost aligns with recent trends (excluding any previous provision for CEP liability and Interconnector Net Transfer Capacity Restrictions) as shown in the graph below.

[3] Subject to the passing of the relevant Trading and Settlement Code Mod.

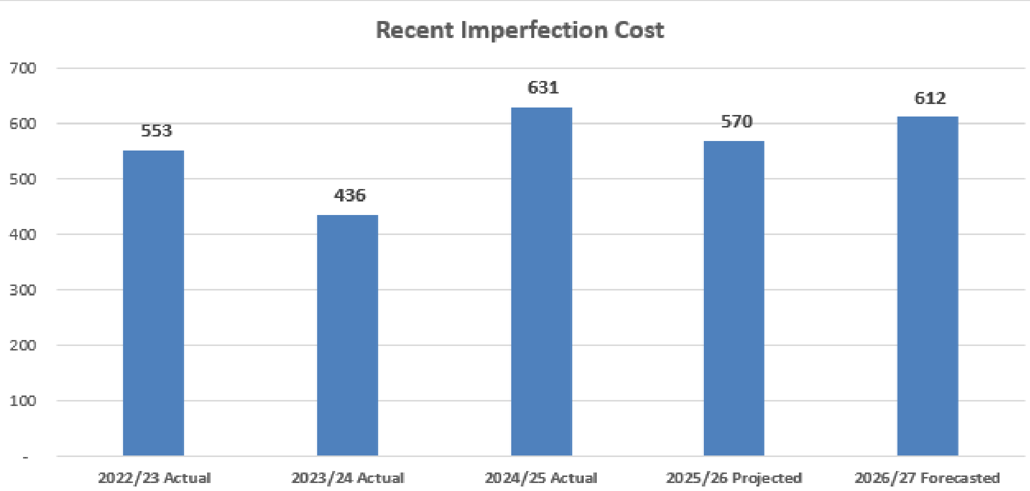

Figure 1 Benchmark of 25/26 Forecast Submission with Recent Costs excluding provision for CEP Article 13(7) and Interconnector Net Transfer Capacity Restrictions

Overall, our modelling suggests an overall forecast which is higher than our 2025/26 projected imperfections costs, but less than 2024/25 actual costs (ex-K factor, ex-CEP provisions and ex-Interconnector NTC restriction provisions).

Based on our PLEXOS model, we have identified the following drivers that are predicting an increase in costs relative to the 2025/26 forecast costs:

- Wholesale fuel and carbon prices: Significantly higher fuel and carbon prices are forecasted for the 2026/27 tariff year and as expected has shown an overall increase in all expenses including Imperfections Costs. Imperfections Costs are extremely volatile to fuel and carbon prices as we have a power system heavily reliant on fossil fuel-based power generation.
- Increased renewable capacity: While our model shows that increasing renewable capacity leads to lower overall system generation production costs and therefore anticipated market price, it tends to elevate Imperfection Costs. This is because it now becomes less likely for units to clear in the market that are necessary to satisfy operational constraints for system security requirements and will therefore have to be run by an out of market action by the TSO's at an Imperfections Cost. It should be noted that the savings from lower generational costs outweigh any increase in Imperfections Costs.
- Increased interconnector Imports: Since the connection of Greenlink, a new 500 MW capacity Interconnector which is now available for the full 2026/27 tariff period, coupled with reduced marginal costs in neighbouring markets have resulted in increased overall Imports from The UK BETTA market to SEM as per recent trends. While this drives down the market price for similar reasons above this tends to elevate Imperfection Costs. Units that would otherwise have cleared in the market are now required to be run without clearing in the market to satisfy system security requirements at an Imperfection Cost.
- Generator outages: the model indicates that outages forecast for 26/27 are more costly than those of the 25/26 forecast. Generator outages have proven to be a significant driver for Imperfections Costs throughout the 2025/26 tariff year to date. This is because when a standard unit (which generally satisfies certain Transmission Constraint Groups) is on outage this must be replaced by an alternative unit. In Tariff Year 24/25 and 25/26, we had a higher number of forced outages to key units than anticipated, which would not have been fully reflected in Forecast costs. While we don't have equivalent long-term outages going into Forecast 26/27, the high number of recent forced outages to key units has translated to an increased forced outage rate in the model, which in turn acts to increase Dispatch Balancing Costs
- Transmission outages: Outages by their nature reduce the capability of the system to transfer power securely in line with market outcomes and will lead to higher Imperfection costs. Due to the level of activity planned on the Network to facilitate the various customer connections and network enhancements over the next number of years, required to meet the objectives set out in

the Operational Policy Roadmap, Transmission Outages will continue to be an increased driver of Imperfections Costs year on year for the next number of years including 2026/27.

On the other hand, our Plexos model suggests that the following factors will exert downward pressure on costs:

- Commercial Offer Data: The TSO's have carried out considerable development work in this area and particularly in relation to the modelling of units that exhibit time varying behaviour in submitted commercial offer data across a day. Through this work the TSO's believe they have significantly increased the accuracy to which generator costs are modelled in Plexos and this approach has resulted in a reduction of Imperfections Forecast Costs in comparison to modelling methodologies used previously.
- Transmission Constraint Groups: Several changes to System Operational Constraint Rules and forecast to be retained or updated in the 2026/27 forecast horizon. These changes are forecast to exert downward pressure on Imperfections Costs. The most notable changes include a reduction of the Northern Ireland minimum set on requirement from 3 sets to 2 sets and the removal of the requirement to carry 50 MW negative reserve from Conventional generator resources.
- Total Energy Demand: Forecasted higher energy demand results in reduction of Dispatch Balancing Costs as this allows must run generator units which are essential to meet network stability requirements to clear in the market to meet energy demand thus reducing overall imperfection cost.

2. Introduction

2.1. Purpose of this report

The purpose of this report is to fulfil our obligations under F.12.1 of the Trading and Settlement Code. This Code states that we must set out proposed values for the Imperfections charge parameters for the upcoming tariff year (see Appendix 1 for the relevant sections of the Trading and Settlement Code).

The report must detail any relevant research or analysis we carried out and how we can justify the specific values we propose. The RAs then assess and the SEMC decides on the values to be used during the Tariff Year.

This submission reflects the forecast of the revenue required from the Imperfections Charge for the 12-month period from 01/10/2026 to 30/09/2027, referred to as the Tariff Year 2026/27. It also reflects the K Factor (the adjustment for under or over recovery in the previous year). The relevant sections of the Trading and Settlement Code are shown in Appendix 1.

2.2. Constraint costs

EirGrid and SONI are Transmission System Operators (TSOs). In this role, the TSOs take actions to ensure the continuous supply of power and system security to customers across the system in real time. As a result, the TSOs may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions is known as Imperfections Costs. Generators receive constraint payments to keep them financially neutral for the difference between the market schedule and the actual dispatch.

Constraint costs therefore arise to the extent that there are differences between the market determined schedule of generation to meet demand (the ‘market schedule’ or ‘Day Ahead schedule’) and the actual instructions issued to generators (the ‘actual dispatch’ or ‘balancing market dispatch’). A generator that is scheduled to run by the market but which is not run in the actual dispatch (or run at a decreased level) is ‘constrained off/down’; a generator that is not scheduled to run or runs at a low level in the market, but which is instructed to run at a higher level in reality is ‘constrained on/up’. There can be associated Imperfection costs for both changes in generator dispatch quantities.

Section 0 below describes the typical areas that can lead to a difference between the market schedule and actual dispatch, and hence constraint costs.

Why do Constraint Costs Arise?

In this section we explore at a high level the key factors that result in Imperfections Costs. Appendix 3 discusses these items in more detail.

Reserve

To ensure the continued security and stability of the transmission system in the event of a generator, interconnector or demand tripping, the TSOs instruct some generators to run at lower or higher levels of output based on the technical characteristics of the unit, where it can provide an automatic fast response known as reserve to counter tripping events. To maintain the demand-supply balance, some generators will be constrained off/down while others will be constrained on/up, again leading to the actual dispatch deviating from the market schedule, which does not account for reserve requirements.

Transmission/Operational Constraints

To ensure the safe and secure operation of the transmission system, it may be necessary to dispatch specific generators to certain levels to maintain compliance with the Operational Security Standards.

Generators may be both constrained on/up or off/down thus leading to the actual dispatch deviating from the market schedule, as the market schedule does not account for any transmission constraints.

Market Modelling Assumptions

Due to mathematical limitations, approximations and assumptions in the market schedule software, the market schedule will not always be technically feasible. This is mainly due to a number of generator technical capabilities and interactions not being specifically modelled (e.g., the market assumes a single generator ramp and loading rate, whereas in reality many generators have multiple ramp and loading rates). In real-time dispatch, the TSOs (and generators) are bound by these technical realities and so the market schedule and dispatch will differ.

Managing Constraint Costs

Constraint costs will inevitably arise due to the factors described above and they are also dependent on underlying conditions. Some of these conditions, such as fuel costs, participants bidding behaviour/ strategy, wind/solar conditions, generator forced outages, trips, transmission network availability and system demand are outside of the TSOs' control. However, the TSOs continually monitor constraint costs and the drivers behind them to ensure that costs which are within their control are minimised.

2.3. Relationship Between Imperfections Forecast and Settlement Components

It is important to note that the categories which we use to describe the imperfections forecast drivers ex-ante are not the same categories in which the outturn costs are observed ex post.

The Imperfections forecast seeks to estimate, as close as possible, the overall pot of funding required to fund the Imperfections Charge which per section F.12.2.1 of the Trading and Settlement Code is levied to recover the anticipated costs for the following:

- Dispatch Balancing Costs (DBC) (less Other System Charges[4]);
- Fixed Cost Payments and Charges; and
- the adjustments for previous years as appropriate.

It is important to call attention to the difference between our input forecast components on the one hand versus our outturn dispatch balancing costs on the other because the former do not map neatly to the latter. The TSOs are in the process of developing a methodology to estimate Imperfections Costs to particular reason categories (i.e., to be able to say that some component of outturn imperfections costs was driven by some particular cost driver[5]), but we do not feel significant insight would be gained by mapping these forecast costs to settlement components which is not technically possible by the current forecast methodology.

Thus, while we seek to forecast Imperfections costs by modelling Generator Complex Commercial Offer Data, Fuel and Carbon Prices, Forecast Demand, Operational Constraints, etc., what we actually observe ex-post are outturn SEM Settlement Components. SEM Settlement components are essentially different

[4] Other System Charges are charges levied outside the Single Electricity Market by the TSOs. They include Trip Charges, Short Notice Declaration charges and Generator Performance Incentive charges.

[5] The TSOs note that this is a price control incentive requirement for EirGrid only under the PR6 arrangements, see section 2.2.2. of the PR6 user guide CRU2025200d_-_Price_Review_Six_-_User_Guide_Annex_D_Performance_Incentives_-_V1.0.pdf

dispatch balancing costs/payments which make up Imperfections costs, and they are described in Table 3 below. Figure 2 shows the relationship between constraint costs, DBC and imperfections costs.

Dispatch Balancing Cost	Description	Imperfections Forecast Treatment
Constraint Costs		
CPREMIUM	Paid when an offer is scheduled in balancing (and delivered) at an offer price above the imbalance settlement price.	**Conventional Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined **RESS Units:** No cost deemed applicable **Other Priority Dispatch Units:** No Imperfections cost assumed with units following PN **BESS Units:** No cost accounted for **Interconnector Units:** Forecast via supplementary modelling **Pumped Storage Units:** Forecast via supplementary modelling **DSU Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined **CHP Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined
CDISCOUNT	Paid when a bid is scheduled in balancing (and delivered) at a bid price below the imbalance settlement price.	**Conventional Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined **RESS Units:** Forecast via supplementary modelling **Other Priority Dispatch Units:** No Imperfections cost assumed with units following PN **BESS Units:** No cost accounted for

		Interconnector Units: Forecast via supplementary modelling **Pumped Storage Units:** Forecast via supplementary modelling **DSU Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined **CHP Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined
CABBPO/ CAOOPO	Bid Price Only and Offer Price Only Payments and Charges: an adjustment payment or charge to result in net settlement at the offer price for increments, or bid price for decrements, for undo actions on generators.	Not accounted for due to its difficultly to forecast and relatively marginal size [Managed through K-Factor]
CCURL	Adjustment payment or charge to result in net settlement at a specific curtailment price for curtailment actions on generators.	Not accounted for due to its difficultly to forecast and relatively marginal size [Managed through K-Factor]
Other Dispatch Balancing Costs		
CUNIMB	Uninstructed Imbalance Charges: CUNIMB are charges for imbalances and bids and offers accepted in balancing but not delivered, which were outside of a tolerance. Undelivered quantities are settled at the imbalance settlement price.	Not accounted for due to its difficultly to forecast and relatively marginal size [Assumed that charge will match Imperfections cost and any differences managed through K-Factor]
CTEST	Testing Charges which are applied to units under test.	Not accounted for due to its difficultly to forecast and relatively marginal size [Recognised that charge will likely under-recover Imperfections cost and the differences will be managed through K-Factor[6]]
CEADSU	Energy payments for Demand Side Units (DSUs) at times of energy scarcity when imbalance price exceeds the strike price	Not accounted for due to its difficultly to forecast and relatively marginal size [Managed through K-Factor]

[6] For the 2027 Participant Testing Tariff Consultation, the TSO's plan to propose an approximation methodology in which the Imperfections Costs associated with participant testing can be estimated and if agreed this approach can be used in future Imperfections submissions to account for the forecast costs above charges.

Fixed Cost Payments and Charges		
CFC	**Component** Fixed Cost Payment or Charge: Payments for additional fixed costs incurred, or charges for fixed costs saved from dispatching a unit differently to its market position, if not sufficiently covered through the unit's other payments or charges.	**Conventional & DSU & CHP Units:** Approximate costs forecast through PLEXOS Model for overall CPremium, CDiscount and CFC combined **Other Units:** Currently largely immaterial costs are forecast in relation to this component and as a result are not represented in this forecast model

Table 3 Dispatch Balancing Cost and Fixed Cost Payments and Charges

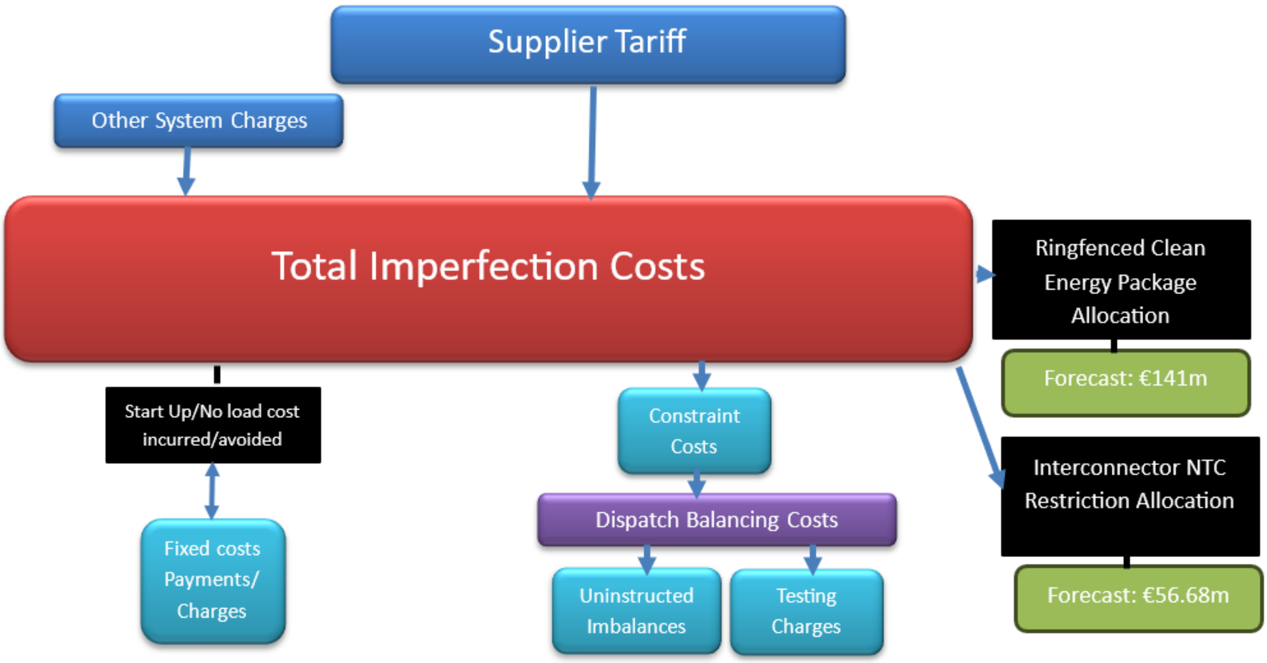

Figure 2 Relationship between Constraint Costs, Dispatch Balancing Costs and Imperfections Costs

Thus, in order to estimate the dispatch balancing costs, the TSO's use a holistic Imperfections forecasting approach which involves a combination of PLEXOS and supplementary modelling. This approach is optimised in a manner that aims to achieve an accurate as possible forecast of the overall Imperfections Costs for the tariff year in question given the input data available to the TSO's 7 to 19 months ahead of time. The PLEXOS model accounts for ~86% of the TSO's overall Imperfections forecast for 2026/27 and is approximated based on the difference in the assumed generator production costs output from a simulated operational generation schedule and the assumed production costs output from a simulated day ahead market schedule both covering the 2026/27 tariff period.

This output is used to forecast the overall cost of the CPremium, CDiscount and CFC settlement components for conventional generators, DSU's and CHP units. This output cannot be broken up into each of these individual settlement components as the PLEXOS model is not intended to be configured in a manner to exactly replicate settlement outcomes. The TSO's have validated this approach for serval years in which actual data is passed through the same process via our 'backcast' model validation process discussed later in this paper and has always shown a high degree of corelation. As a result, it does not appear there is much scope to materially improve the TSO's Imperfections forecast accuracy by seeking to model the settlement system through our Imperfections forecasting model. The TSOs' view is that the greatest source of inaccuracy lies in the availability of key sets of input data that is not available to a high degree of accuracy 7 months to 19 months ahead of time.

Through consultation with the RA's and their consultants, it was recommended that the TSOs further explore the possibility of being able to present Imperfections forecast outcomes correlated to settlement parameters. The TSOs have attempted to fulfil this requirement in as much as it technically possible as outlined in table 3 above. The TSOs contend however, that there is much greater value in devoting time creating an approximation methodology that will allow the TSOs report on Imperfections costs to specific system security, energy policy or other defined tangible drivers. As noted above, this work is being undertaken already, in alignment with the PR6 requirements outlined by the CRU for EirGrid TSO[7] and more detail in relation to this workstream is discussed in Appendix 3.

[7] See section 2.2.2 of the PR6 User Guide and Appendix 3 of this paper for further detail

3. Forecasting Constraint Costs

3.1. What method did we use in forecasting Imperfections Costs?

In making our forecast of Imperfections Costs, we combined the following methods:

PLEXOS Model

PLEXOS is a modelling tool that we use to simulate the Single Electricity Market (SEM). It can be used to forecast dispatch balancing costs over a year using the best available data and carefully chosen assumptions where data must be inferred or explicit modelling is technically infeasible. PLEXOS is a causal forecast model; it explicitly incorporates the relationships between underlying factors such as fuel costs, outage schedules and constraint/reserve requirements.

The primary aim of our PLEXOS modelling is to forecast an overall Imperfections liability for the tariff year in question for conventional generators, CHP generators and Demand Side Units whose costs are explicitly modelled in the tool. The outcome of this is not considered to be accurate on an Imperfections component basis or for any subset of the year. Our forecasting processes are optimised on this basis due to the fact that accurate critical input data is not available at the time of our forecast activity, which spans a period from 7 months to 19 months ahead of time. Long term forecasts of variable generator availability and firm Transmission and Generator outage programmes are not available to a high degree of accuracy at this point in time, and as a result the impact of these requirements are catered for via their variable application to the PLEXOS model aligned with their historical prevalence. Due to the significant impact of these inputs on Imperfections costs, it only makes sense to measure accuracy against the overall cost outcome of this model.

Supplementary Model

Some Imperfections Costs cannot be accurately modelled in PLEXOS largely due to the immaturity of the input data that drives them. For these costs, we carry out supplementary modelling. We then add the outcome of this supplementary modelling on top of the PLEXOS model to arrive at the overall Imperfections forecast. Much of the forecasts in the supplementary model are based on historic data. It assumes that the past is a good basis for forecasting the future.

The supplementary forecasting methods we have used for the 2026/27 Forecast are consistent with previous years' approach.

Model Validation

As part of our imperfections work, we also run a Backcast Model. The Backcast process commences after the last full tariff year has completed. This exercise starts with the original forecast model for that tariff year, but rather than running the model with the same values assumed during the forecast, we update the model using actual data from the period. For the Backcast process, we apply the same approximation assumptions on the actual data that we carry out in our Imperfections forecast. This allows us to measure Backcast outputs against actual data, validates the model, and provides insight which can be used to improve future forecasts by ensuring our approximation applied to input data is well correlated to actual outcomes. All historic Backcast Reports are published on the SEMC website.

3.2. PLEXOS Forecast Model

The PLEXOS model can produce an hourly schedule of generation, with associated costs, to meet demand for a defined study period.

We have set up two PLEXOS models showing the dispatch for each hour over the 2026/27 period (1st October 2026 – 30th September 2027):

1. Unconstrained model

This represents the market schedule (Day-Ahead schedule) of generation dispatch.

2. Constrained model

This represents the actual generation dispatch. It considers the constraints needed to keep the transmission system secure and reliable.

The constraint costs are then assumed to be the difference between the constrained and unconstrained models (which represents the difference between the assumed production cost of actual dispatch and market schedule).

Conventional generators account for the main share of Imperfections Costs, compared to other technologies. The ratio of conventional generator costs to other technologies is similar to that of the ratio of costs between our PLEXOS model and our Supplementary model. For the PLEXOS model, we only include a representation of commercial offer data for conventional generator units[8] equating to the assumed production costs for a plant. The PLEXOS model accounts for the forecasted interaction of other technologies in both the market schedule and the operational (i.e. actual) schedule of how all generation is forecasted to run. The overall difference in the assumed conventional generation production costs of the constrained run to the unconstrained run seeks to closely approximate the total annual CPremium, CDiscount and CFC costs of all conventional generators on the system for the tariff year in question. The application of this approximation methodology has proven to closely correlate to actual outcomes as demonstrated through our annual Backcast reports.

Key Modelling Assumptions

PLEXOS uses a detailed model of the transmission and generation systems across the whole island with key inputs such as wholesale fuel costs, generator outage schedules, demand levels, plant availability, and wind/solar profiles.

The model also considers reserve requirements and specific transmission constraints. In Appendix 2 you can read the key assumptions we used to set up the PLEXOS model.

[8] Demand Side Unit and CHP commercial costs are also accounted for in the PLEXOS model but account for a marginal share

3.3. Supplementary Modelling

PLEXOS captures most forecast Imperfections costs. However, there are some costs which cannot be modelled in PLEXOS. For the forecast of these additional costs, we use supplementary modelling. This includes the following costs:

- System Operator Interconnector Counter Trades;
- Dispatch of Pump Storage Units;
- Constraint payments to Wind and Solar;
- Energy Imports for Units in System Services modes;
- Interconnector Net Transfer Capacity restrictions;
- Clean Energy Package

The forecast of these costs is based on historic data; full details of the methodology behind each estimation is outlined in Sections 4.2.2 to 4.2.5.

3.4. Forecast Model Limitations

The forecasting of imperfections is complex, as the actual spend on imperfections has many interacting variables. PLEXOS will never exactly reflect operational reality (even with the supplementary modelling). The model is also limited to being set up for a 12-month study and therefore cannot be used to produce an estimate for any one specific day, month or period of the year. It is therefore important to consider all results in this context.

Risk-factors in Forecast

Several risk-factors should be considered when assessing the anticipated imperfections costs for 2026/27. These factors could individually, or collectively, result in a significant difference between the forecast and actual imperfections costs. A set of key risks are outlined below:

Wholesale fuel prices

Wholesale fuel prices are a key input to the forecast. The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long-term fuel prices as of May 2026. Recent prices have been characterised by extreme volatility.

SEM Design and modifications to the SEM Trading and Settlement Code

We have based our assumptions in this submission on the current version of the Market Rules (Version 31, dated 13/11/2025). In respect of the provision regarding Article 13(7) of Regulation (EU) 2019 / 943, we have also considered the SEMC decision SEM/22/009 and the ongoing judicial review process in Ireland in respect of same (see section 4.3 of this submission). We have also included historical costs associated with Interconnector Net transfer Capacity restrictions imposed by the TSO as there is a SEMC proposal that these costs will be recovered through the Imperfections tariff.

Items of Uncertain Impact

Any unforeseen Modification implemented on Version 31 of the Trading and Settlement Code and made active during the 2026/27 tariff period not accounted for in this report poses the risk of reducing our forecast accuracy.

Participant behaviour

The PLEXOS modelling process has assumed that participants offer into the market in line with their fuel costs and technical availability. We have not made extra provision for any possible bidding strategy by a market participant. We have assumed the Bidding Code of Practice (BCOP) is followed for their complex commercial offer data.

It is assumed bidding behaviour of all participants will remain consistent with our average representation of their commercial offer data in line with their last 12 months of bidding.

High Impact, Low Probability Events (HILPs)

HILPs are low probability transmission, generation or interconnector outages that lead to significant increases in constraint costs. For example, a long-term unplanned outage of a critical transmission circuit due to a fault on an underground cable that could take a long time to repair. This may result in generation being constrained, until the repair can be completed.

Reduced generator availability

A reduction in the overall availability of generation could lead to an increase in Dispatch Balancing Costs. This is because relatively more expensive generation may be needed to provide reserve and/or system support, in areas with transmission constraints.

Variable renewable generation

Wind/solar generation is inherently unpredictable and are a significant factor in imperfections cost.

Forced outages of transmission plant

The forced outage of a transmission plant may lead to increased Dispatch Balancing Costs due to resultant generator and/or transmission constraints. The outage of certain key items of the transmission system can increase Dispatch Balancing Costs significantly.

Testing charges

There is no specific Imperfections Costs provision for:

- new units that will be under test before they are commissioned; or
- units returning from a significant outage.

We assume that the testing charges will somewhat offset the additional Dispatch Balancing Costs incurred. This will primarily consist of constraints, due to out-of-merit running or dispatch down to make room for the test profile incurring CDiscount Costs.

The 2026 Participant Testing Tariff Consultation concluded that all Imperfections Costs incurred during participant testing would not be covered by the Testing Tariff. Through this work, however, the TSOs were not able to establish a definitive Imperfections Costs incurred during a participant's test, and it was considered prudent to maintain the tariff at a rate that would not discourage testing on the system. In line with a requirement from the CRU as part of EirGrid TSO's PR6 arrangements[9], we are developing an approximation methodology that could be used to estimate Imperfections Costs to definitive reasons. It is targeted that this methodology will be signed off internally and with the regulator by the end of 2026, at which point we will have an agreed methodology that could be considered to quantify increased Imperfections Costs forecast not catered for through the Testing Tariff. In the Interim, excess costs experienced for 2026/27 will be managed through the K-Factor.

Increased CPremium and CDiscount Costs

The PLEXOS model does not fully capture all SEM settlement rules.

A feature of SEM settlement rules is that if a generator's actual dispatch differs from its market schedule, it gets paid:

[9] See section 2.2.2 of the PR6 User Guide CRU2025200d_-_Price_Review_Six_-_User_Guide_Annex_D_Performance_Incentives_-_V1.0.pdf

- the greater of their offer price and imbalance price, for increments, with all top-ups from imbalance price to offer price accounted for via the CPremium Imperfections component; and
- A discount on its charge to the magnitude of the difference in offer price and imbalance price, for decrements accounted for via the CDiscount Imperfections component.

The PLEXOS model broadly captures this feature of SEM Settlement rules by capturing if the imbalance price is between the generator constrain-down (decremental) offer price and the generator constrain-up (incremental) offer price.

However, PLEXOS does not capture the scenarios where:

- the imbalance price is greater than the generator incremental offer price; or
- the imbalance price is lower than the generator decremental offer price.

To approximate for these two features of SEM settlement rules, the TSO's historically carried out additional calculations outside of the PLEXOS model. This calculation involved applying the CPremium and CDiscount market formulae to the dispatch volume change between the unconstrained and constrained models.

Another feature of SEM settlement rules, which could not be captured in PLEXOS, is that generators can sometimes be settled on their simple bids rather than complex bids. Simple COD is utilised for energy actions taken after the closure of intra-day energy markets at Gate Closure 2. The impact of this feature was also historically approximated in the supplementary modelling, based on the proportion of time over the recent past that the generators had been settled on simple offers.

This year the TSO's have carried out a detailed review of this standard process and through validation with the 2024/25 outturn model have become less confident of its capability to accurately adjust PLEXOS determined cost elements for conventional units to account for market rules not catered for through PLEXOS. As a result, we have not submitted for these costs in the supplementary modelling, which therefore poses an additional risk that Imperfections costs for conventional units are understated in this Imperfections forecast.

Additional security constraints

We have prepared this forecast using the best estimate of operational policies that will be in effect for the tariff year. As the system develops, these policies may no longer be required, or additional security constraints may be required. This could result in a change in Imperfections Costs.

Impact of CBAM on SEM-GB Interconnector Flows

The Carbon Border Adjustment (CBAM) is the EU's tool to put a price on carbon emitted during the production of carbon-intensive goods that are entering the EU, and to encourage cleaner industrial production in non-EU countries. Electricity production and cross-border transportation of this is in scope for CBAM, and this came into effect in 2026. We have observed no appreciable change in SEM-GB interconnector flows since it has come into effect and therefore have made no changes to our approach to interconnector modelling.

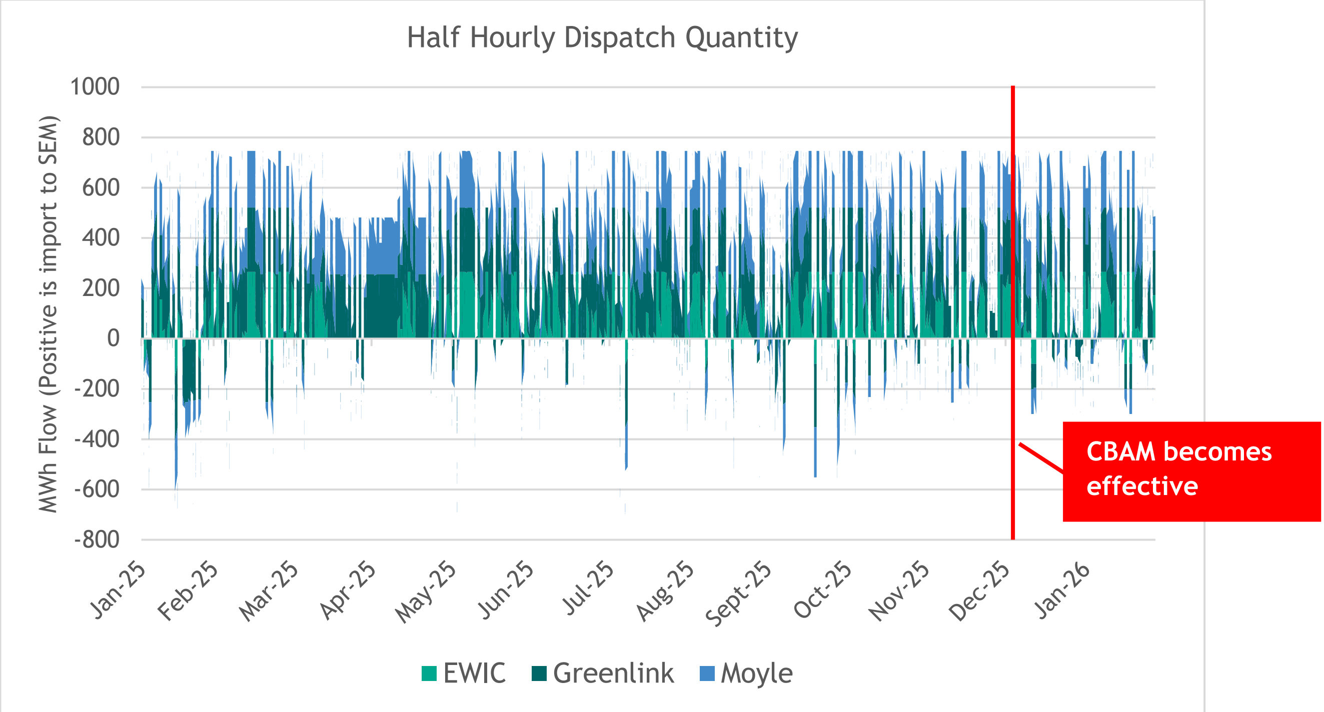

Figure 3 Standard trend of BETTA-SEM Interconnector schedule outcomes

There is a risk, however, that CBAM has an increasing influence on flows as time progresses, and the current trend of heavy importing from GB to SEM reduces. If this comes to pass, it will have an impact on our imperfections forecast accuracy.

The current trend of interconnector flows typically follows the below diagram:

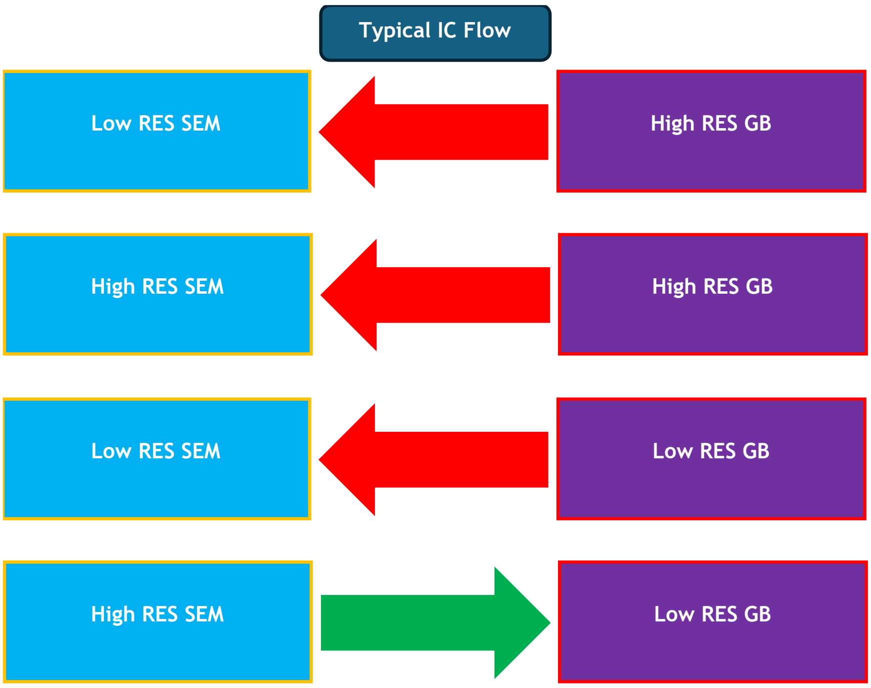

Figure 4 Typical Interconnector schedule outcome linked to relevant Jurisdiction RES Availability

4. Forecast Constraint Costs

This section sets out our forecast of imperfections costs for the tariff year 2026/27. Our forecast of 2026/27 Imperfections Costs alongside values for the 24/25 Backcast and 25/26 Allowed Revenue is shown in Table 4.

Component	2026/27 Forecast (€m)	2025/26 Allowed (€m)	2024/25 Backcast (€m)	Difference (€m) 26/27 FC - RA- RA Approved 25/26	Difference 24/25 Backcast & FC 26/27 (€m)
PLEXOS model	525.68	493.96	553.48	31.72	(27.8)
Supplementary model	86.78	75.85	77.09	10.93	9.70
TOTAL	612.46	569.81	630.57	42.65	(18.1)

Table 4 2026/27 Imperfections Forecast

The following sections detail the PLEXOS and supplementary forecast models.

4.1. PLEXOS results

The 2026/27 forecast Model was developed using the 2024/25 Backcast Model as its starting point. This is the same approach as last year and further detail is provided below.

2024/25 Backcast Model

The 2024/25 Backcast Model uses various approximated inputs based on actual data for the period 2024/25, resulting in an ex-post adjusted forecast known as the '2024/25 backcast". Detailed information about the 2024/25 Backcast Model, including its description and results, can be found in the report submitted to the RAs accompanying this forecast submission.

Using the 24/25 backcast model as a starting point serves as a validated reference point, as the total backcast costs for 2024/25 fall within the general range of the of the actual costs for that year (outturn variance was 0.05%). We then incorporated anticipated changes for 2026/27 into this base model to assess their impact.

A summary of the 2022/23 actual costs, the 2023/24 actual costs, the 2024/25 actual costs, the 2024/25 backcast model costs, the year-end projected 2025/26 Costs (estimate as of May 26) and the 2026/27 Forecast Costs are shown in Figure 5.

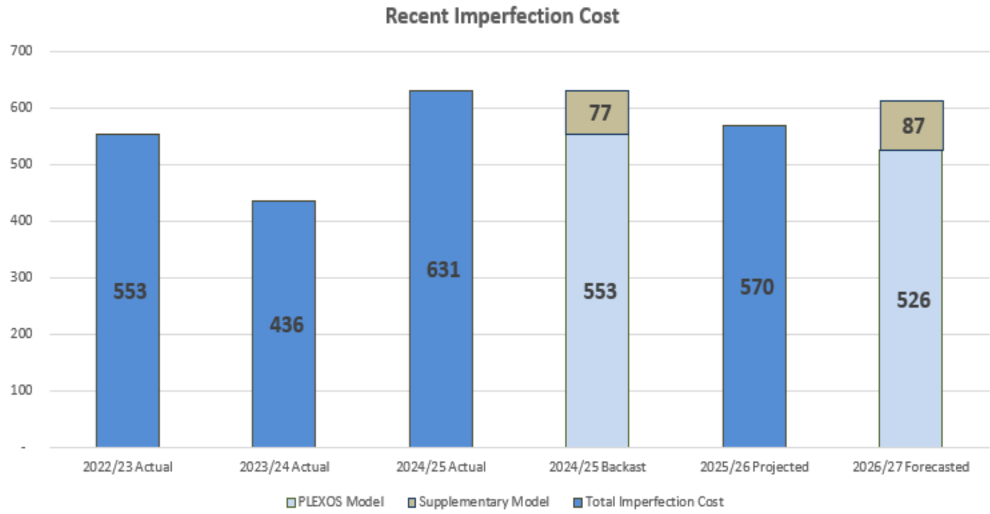

Figure 5 Recent Imperfections Costs (2026/27 Forecast Costs exclude provision for CEP Article 13(7) and Interconnector Net Transfer Capacity Restrictions

We have undertaken a “Take-Out-One-at-a-Time” (TOOT) analysis to determine the approximate scale of each single input change relative to the final model. This allows us to see how each individual factor relatively affects costs in comparison to another input that is passed through the same analysis. This involved starting with the final 2026/27 Forecast model and then taking out one input at a time and replacing it with what was in the previous 2025/26 forecast model. The relative impact of Imperfections Cost drivers and Cost suppressors is shown in Figure 6 below. Due to the significant interdependency between input data it is not possible to definitively determine the quantitative impact of individual component to Imperfections costs. We are carrying out considerable work to develop an approximation methodology that will allow Imperfection cost elements to be estimated to reasons. Further details in relation to this work is outlined in Appendix 3.

Through engagements with the RA’s and their consultants several different forms of “Take-Out-One-at-a-Time” (TOOT), “Add-One-in-at-a-Time” (AOT) and bridging analysis approaches were investigated. The outcome of these various forms of analysis was reported to the TSO’s in the context of the 2025/26 Imperfections forecast model. Given the scale of the proposed additional modelling within the process time constraints in the 2026/27 Imperfections forecast workstream it was not possible for the TSO’s to introduce this additional analysis for the 2026/27 modelling process. It was agreed with the RAs that analysis showing the relative cost drivers between tariff periods would satisfy the same essential requirements as the modelling additions proposed by the RAs, which within the TSOs’ 2026/2027 submission has been fulfilled through the TSO’s existing TOOT methodology. The TSO’s, however, have examined in detail the new forms of analysis provided to the TSO’s by the RA’s and their consultants and have outlined our rationale as to why the conclusions drawn out of RAs’ proposed additional analysis are fundamentally considered within the existing 2026/27 Imperfections forecast model. This commentary is provided in Appendix 3 of this report.

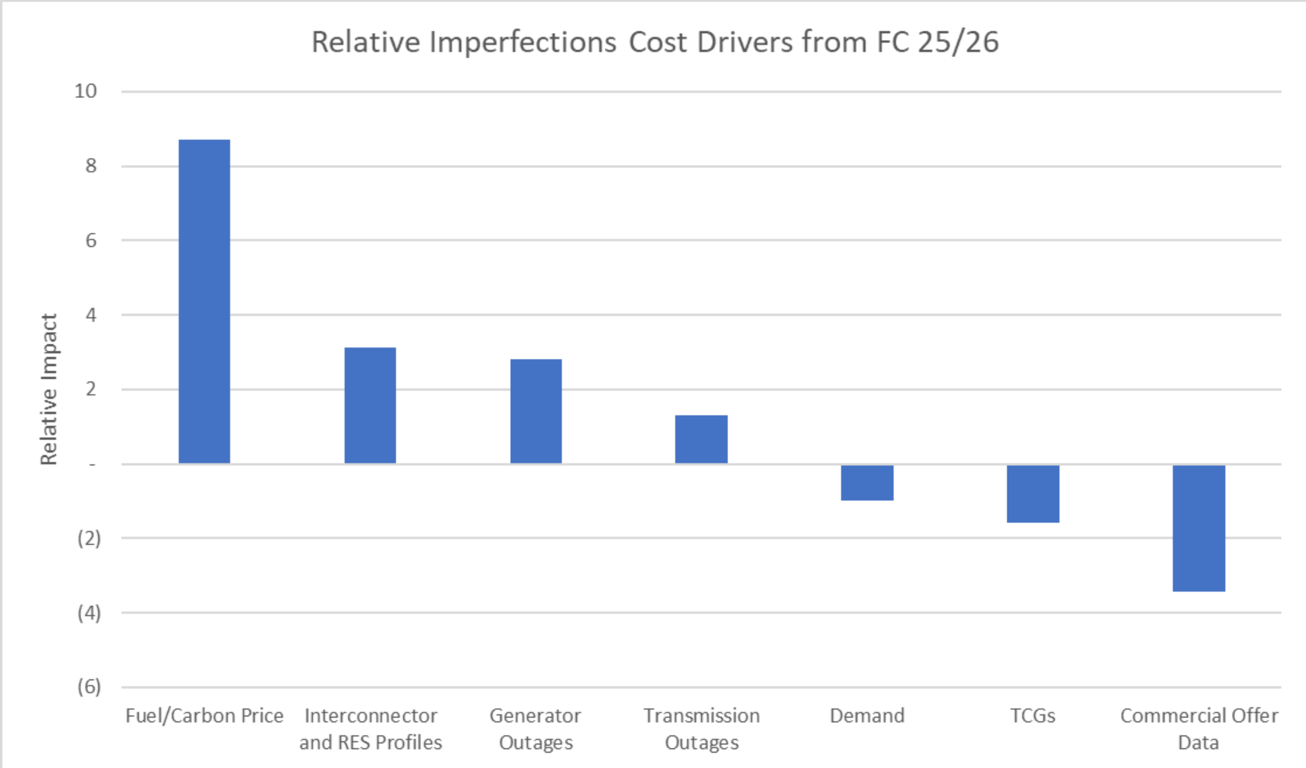

Figure 6 Taking Out One at a Time (TOOT) Analysis on the 2026/27 Forecast Model

These measures of relative impact can be interpreted as the effect of a marginal increase of each corresponding input on the direction of imperfections costs overall normalised to the lowest absolute impact driver analysed i.e. Demand. Reading this graph, it can be inferred that fuel/carbon costs are an upward driver of Imperfections costs in the 2026/27 Imperfections forecast relevant to the 2025/26 Imperfections forecast. It can also be inferred that this driver has a ~9 times impact on the forecast outcome than changing the demand levels. Equally you can infer that TCG's is a downward driver of forecast costs from 2025/26 and has ~1.5 times impact than changing the demand.

The most significant influences on forecast constraint costs shown in the PLEXOS model based on the above analysis are shown below in Table 5.

Influence	Change to Imperfection cost	Relative Impact Normalised to Demand TOOT
Fuel & Carbon Price	Increase costs significantly	8.71
Interconnector and RES Profiles	Increase costs	3.12
Generator Outages	Increase costs	2.82
Transmission Outages	Increase costs marginally	1.31
Demand	Decrease costs marginally	-1
TCGs	Decrease costs marginally	-1.59
Commercial Offer Data	Decrease costs	-3.44

Table 5 The relative impact of various cost drivers comparing FC26/27 to FC25/26

Further detail on these underlying factors is provided in the following sections.

Fuel Prices/Carbon Prices

Wholesale fuel and carbon prices are a fundamental driver of imperfections costs volatility.

Figure 7 outlines the differences in the fuel prices between the 2025/26 forecast and the 2026/27 forecast. The cost of fuel between these models has increased significantly. This makes the cost of constraining on out-of-merit generation more expensive and drives a higher production cost in the constrained model. The result is that the disparity between the unconstrained and constrained model production costs increases, and with it, the Dispatch Balancing Costs.

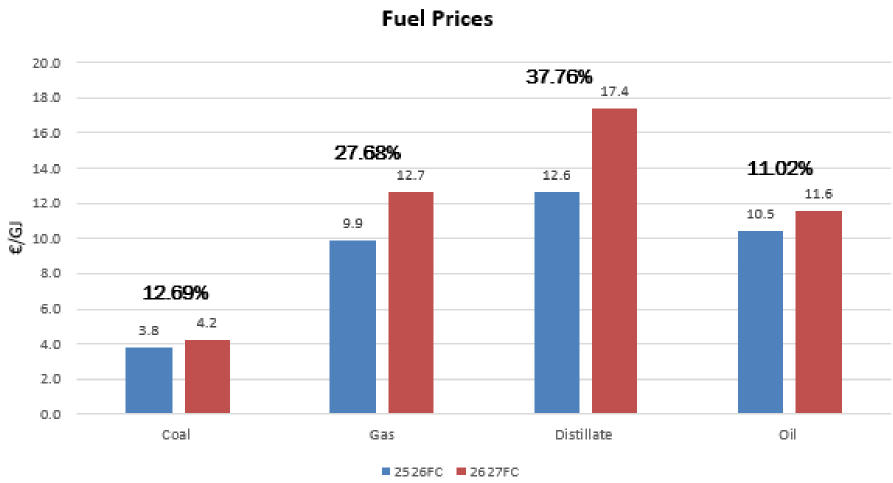

Figure 7 Fuel Cost Changes from 2025/26 forecast to 2026/27 forecast

As shown in Figure 8 (below), carbon costs have decreased. This results in a minor difference between the constrained and unconstrained model production costs, resulting in reduced Imperfections Costs.

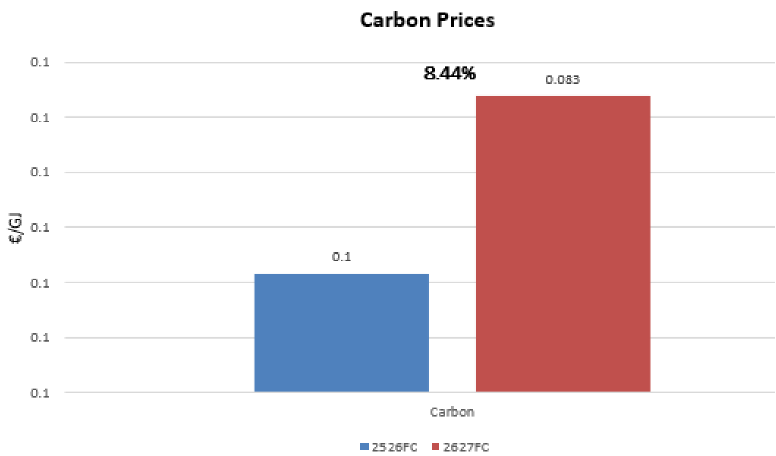

Figure 8 Model Carbon Cost Changes from 2025/26 forecast to 2026/27 forecast

Updated Renewable Energy Sources (RES) & Interconnector Capacities

As there is a link between interconnector flows and renewable availabilities, these were analysed together rather than individually.

The availability of renewable generation sources is extremely difficult to forecast to any degree of accuracy a year in advance, as this is driven by highly variable weather conditions. At the same time, this input has significant influence on the Interconnector flows. For the 2026/27 Forecast, an annual historical profile of these linked inputs from the 1st February 2025 to 1st February 2026 was used to represent the annual variability of these over a full Tariff Year.

The 26/27 Forecast predicts an increase in renewable generation from wind and solar compared to the 2025/26 Forecast as these profiles have been scaled upwards based on new connections expected to be present throughout the period. This model shows that this increased level of renewable energy has implications for imperfections costs.

To determine total connections in the model, we considered:

- Actual connections as of 31st March 2026.
- Anticipated connections as of 31st March 2026, up to 30th September 2027, based on build-out rates from the All-Island Resource Adequacy Assessment (AIRAA) 2026-2035, Infrastructure connection project timelines, current considerations for Transmission Outage Programmes and current considerations for commissioning and testing programmes.

While our model shows that increasing renewable capacity leads to lower overall system generation production costs and therefore anticipated market price, it tends to elevate Imperfection Costs. This is because with increased renewables it becomes less likely for units to clear in the market that are necessary to satisfy operational TCGs and will therefore have to be met by an out of market action by the TSOs at an Imperfections Cost.

The forecasted interconnector flows for 2026/27 are based on fixed flows derived from historic profiles between SEM and BETTA markets from the 1st February 2025 to 1st February 2026 aligned with the RES profiles from the same sample period.

Greenlink interconnector went live on the system on 29th January 2025, which has driven the selection of the referenced sampling period. The trend on Greenlink was for significant imports across the majority of this period. This was a consistent outcome to all other SEM-GB interconnectors and has continued to be the case since the go-live of the Carbon Border Adjustment Mechanism on 1st January 2026.

While interconnector imports act to drive down the market price for similar reasons to the RES profiles above, they tend to elevate Imperfection Costs. Units that would otherwise have cleared in the market are now required to be run out of market to satisfy system security requirements at an Imperfections Cost.

Generator Outages

Both scheduled and forced generator outages are considered in the PLEXOS model. Generator scheduled outages are based on the latest available information at the time of the data freeze. Forced outages are modelled with a Generator Forced Outage Probability factor and a Mean Time to Repair, which are both based on analysis of historic data.

The model reveals that generator outages in the 26/27 Forecast have a higher cost impact on imperfections compared to those in the 2025/26 Forecast. The cost impact of generator outages is significantly influenced by other system factors and conditions, including wind levels, other units experiencing forced outages, and demand levels. Generator outages have proven to be a significant driver of Imperfections Costs throughout the 2025/26 tariff year to date. One of the primary reasons for this is when a unit goes on outage that typically satisfies certain Transmission Constraint Group requirements, it is replaced in the TCG by a more expensive unit. The replacement unit may be orders of magnitude more expensive than the original unit, significantly impacting Dispatch Balancing Costs.

In Forecast 25/26, there was a number of long-term forced outages to key units that acted to increase the Dispatch Balancing Costs for that year. In Tariff Year 24/25, we had a higher number of forced outages to key units than anticipated, which would not have been fully reflected in Forecast 25/26. While we don’t have equivalent long-term outages going into Forecast 26/27, the high number of recent forced outages to key units has translated to an increased forced outage rate in the model, which in turn acts to increase Dispatch Balancing Costs.

Partial Representation of Transmission Outages

When the system is subject to multiple Transmission Outages, the TSO’s are required to restrict the output of generation sources that have cleared in the market to remain compliant with the Operational

Security Standards. The cost of these actions come in two forms, the compensation required to be paid to generators that have been restricted and compensation to generators that must be increased to meet the resultant generation shortfall.

As Transmission Outage Programmes are planned well in advance to meet project delivery requirements, the following general principles are followed.

- Due to generation capacity concerns, it is ensured that conventional units that have a high predicable level of availability are unrestricted by Transmission Outages in 0 MW renewable conditions.
- Generation restrictions are permitted by Transmission Outages under high renewable availability system conditions as generation capacity concerns are no longer present.

In previous years, we conducted a desktop exercise based on the indicative transmission outages scheduled to take place during the upcoming tariff year, focusing on a representative set of outages to feed into PLEXOS for estimating Dispatch Balancing Costs. In Forecast 25/26 we introduced an improved methodology to estimate costs, which we have continued for Forecast 26/27.

As detailed in section 4.1.2, the RES availability profile for the 2026/27 Imperfections forecast was derived from the actual availability profiles that occurred in a sample period from 1st February 2025 to 1st February 2026. These profiles were scaled up based on the new available Renewable Capacity planned to be connected throughout 2026/27 and were applied to the PLEXOS unconstrained model to replicate the market outcome. Instead of inputting a selection of Transmission Outages into the PLEXOS constrained model, we adjusted the RES availability profiles by the MWh quantity of renewables that were dispatched down within the same 2025/26 sample period, classified as “TX Constraint” reasons, and applied these availability profiles to the constrained model. This accounts for both the base case[10] restrictions that would be automatically carried out by the constrained PLEXOS model, as well as the additional restrictions caused by the Transmission Outages in the same date range.

The unconstrained PLEXOS model then ran additional least cost generation to meet the shortfall at an Imperfections Cost, providing a proxy for partial Imperfections Costs. Adding this to the supplementary item “Constrained Wind” provides an overall proxy forecast for the 2026/27 basecase network restrictions and Transmission Outages.

While we think this approach is more representative, we think it is prudent to flag below risks and limitations with this approach that could underestimate the Imperfections Costs for Transmission Outages, including:

- In medium to low renewable conditions, some local restrictions might be in place that prevent conventional generation sources from generating their full market position. This will have Imperfection Cost implications that are not accounted for by this approach.
- Once firm Transmission Outage schedules mature, it might be determined that the above principles could not be followed, and generation restrictions of conventional plant in 0 MW renewable conditions might be required to deliver a key infrastructure project.
- Once firm Transmission Outage schedules mature, it might be determined that additional Operational Constraint rules might need to be introduced to facilitate the programme of outages securely at an Imperfections Cost not factored into the above approach.
- There is a continued increase in the quantity of key infrastructure projects requested year on year and therefore an increased level of Transmission Outages are required to occur simultaneously and further into the winter months. Modelling an Imperfections Cost proxy for Transmission Outages based on sample 2025/26 conditions might under-estimate the cost of the 2026/27 requirement with an anticipated increase in outage requirements.

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[10] Inherent weakness in the TSO network not associated with Transmission Outages that if not reflected in the profile would be restricted by PLEXOS network model to the same quantity.

Revised Demand

The forecast demand is taken from the median scenario of the All-Island Resource Adequacy Assessment (AIRAA) 2026-2035, which projects an increase in demand in the Forecast 26/27 period.

While higher demand puts upward pressure on the market price due to the increased energy that needs to be served, it generally has a positive impact on Imperfections Costs (i.e., reduces imperfections costs). The higher demand increases the likelihood of units to clear in the market that otherwise would have to be run out of market to satisfy System Security requirements at an Imperfections Cost.

In line with the findings of the AIRAA, there remains a risk of unserved energy over the coming years. This is reflected in the Imperfections PLEXOS model which contains small periods of unserved energy. In practice, if required this energy will be met by the running of out-of-market units such as Moneypoint units 1, 2 and 3, and Temporary Emergency Generation (TEG) at no increased Imperfections Cost.

TCGs

The best estimate of operational policies/Transmission Constraint Groups (TCGs) changes that will be in effect for the Tariff Year as of 1st May 2026 has been considered in the model, as summarised in Table 6 below.

Operational pathway	Treatment in 2026/27 Forecast Model
System Non-Synchronous Penetration (SNSP)	75%[10]
Inertia	23,000 MWs[11]
All-island Minimum Set Requirement	7 units throughout 2026/27 model
Northern Ireland Minimum Set Requirement	2 set rule throughout the 2026/27 model
Ireland Minimum Set Requirement	4 set rule throughout the 2026/27 model
Negative Reserve from Wind NI[12]	The full 50 MW negative reserve requirement is carried by wind when it is sufficiently available throughout the 2026/27 model

Table 6 Summary of Operational Policies included in 2026/27 Forecast (as of time of model data freeze, 1st May 2026)

The Northern Ireland System has the capability to run with a minimum set rule of 2 large units. This TCG reduced from a requirement of 3 units to 2 units on a trial basis and is now established operational policy. The reduced requirement was the largest driver of cost reduction in the TCG TOOT.

As of 1st May, SONI is planning to trial the implementation of sourcing negative reserve from wind. This was implemented for the full Forecast 26/27. This too was a downward driver of Dispatch Balancing costs but not to the degree of the NI 2 set rule with the TOOT analysis determining this as being 10 times more effective

Despite this, the implementation of this approach marks a significant milestone in the evolution of Northern Ireland operational policy.

As of 1st May, inertia requirements on the system did not change. This was included as a TOOT step, however, as it relates to the way in which we model Synchronous Condensers. Typically, conventional sets clearing in the market and other system constraints such as the All-Island Minimum Set Requirement ensure that the system has sufficient inertia, without the inertia constraint itself binding. If the system is short of inertia, we assume that the most economic generation schedule will have all available

[11] Same as existing required but just quoted for completeness

[12] This is a forecasted operational change anticipated to be in effect for the full Tariff Year 26/27

synchronous condensers dispatched on, so effectively in our model we can net off the inertia contribution of all available synchronous condensers from the system requirement. The system service costs of synchronous condensers is covered outside of Imperfections and the Imperfections component of the energy required to be consumed by the system service provider in order to provide this service is accounted for through the supplementary model. The effective change to inertia requirement associated with the connection of additional synchronous condensers in Forecast 26/27 had a marginal impact on Dispatch Balancing Costs.

Generator Complex Commercial Offer Data.

We have significantly increased the complexity of the analysis we perform on generator Complex Commercial Offer Data for Forecast 26/27. We analysed half-hourly COD for all units for a 12-month period from 1st March 2025 to 1st March 2026. As part of our approach, we removed the influence of fuel cost by normalising participant submissions by daily fuel cost to determine underlying COD parameters. We also analysed COD submissions on a half-hourly basis to determine if there was any intra-day patterns to participant bidding behaviour. A strong daily pattern was identified for several units, which was successfully modelled in Forecast 26/27.

Further detail on our approach to COD can be found in Appendix 4.

4.2. Supplementary Modelling Results

The supplementary model costs for the tariff year 2026/27 are €86.78m. This represents an increase of €10.93m from the 2025/26 Approved Costs. The results of model costs and supplementary costs for 2026/27 are summarised and compared to the 2025/26 Approved Budget and 2024/25 Backcast costs in the table below.

Description	2026/27 Forecast (€m)	2025/26 RA Approved (€m)	2024/25 Backcast (€m)	Difference 25/26 RA Approved & FC 26/27(€m)	Difference 24/25 Backcast & FC 26/27(€m)
PLEXOS Model	525.68	493.96	553.48	31.72	(27.8)
Additional PREMIUM and DISCOUNT impact	0.00	0.00	0.00	0.00	0.00
Interconnector Counter Trades	22.64	19.69	16.13	2.95	6.51
Pump Storage Running	18.97	19.66	25.83	(0.69)	(6.86)
Constrained Wind	44.25	34.92	33.60	9.33	10.65
Payment for energy imports for units in system services modes	0.93	1.58	1.52	(0.65)	(0.59)
Supplementary Model Total	86.78	75.85	77.09	10.93	9.70
CEP Article 13(7)	141.00	37.00	158.00	104.00	(17.00)
Interconnector Net Transfer Capacity Restriction Compensation	56.68[13]	0.00	0.00	56.68	56.68
Total	810.14	606.81	788.57	203.33	21.57

Table 7 Summary of 26/27FC Imperfection Costs compared to RA approved 25/26 and Backcast 24/25

4.2.1. Additional CPREMIUM and CDISCOUNT payments and Imbalance Price impact

The imbalance price under the revised SEM arrangements is, at a high level, determined by the incremental and decremental costs of generators used for energy actions in the balancing market. The market pays generators the greater of their offer price and imbalance price, for increments, and A

[13] Subject to the passing of the relevant Trading and Settlement Code Mod

discount on its charge to the magnitude of the difference in offer price and imbalance price, for decrements.

The vast majority of the annual CPremium and CDiscount costs for Conventional generators is approximated through PLEXOS via a comparison between the assumed generator production costs of the simulated market dispatch and the simulated operational dispatch. The CPremium and CDiscount supplementary model historically investigated if these cost estimates needed to be adjusted to account for market rules not catered for through PLEXOS including discount costs for MW decrements, the occurrence of settlement through more costly simple prices and the reduced increment costs from market price instead of market position.

This year the TSO's have carried out a detailed review of this standard process and through validation with the 2024/25 outturn model have become less confident of its capability to accurately adjust PLEXOS determined cost elements for conventional units to account for market rules not catered for through PLEXOS. As a result, the TSO's will not be submitting this requirement for the 2026/27 Imperfections forecast. This is noted above in the risk commentary in section 3.4 and the TSO's will undertake a full review of its appropriateness if submitting for this requirement in future submissions.

4.2.2. System operator interconnector countertrading

For the 2026/27 forecast, an allowance of €22.64m for countertrading is requested. This allowance has been based on actual cost of countertrades to imperfections in the last 12 months from the 1st of May 2025 until the 30th of April 2026. The TSO's have noted a trend of significant increases in Imperfections costs associated with Interconnector countertrading since November 2025 as can be seen from the figure 9 below.

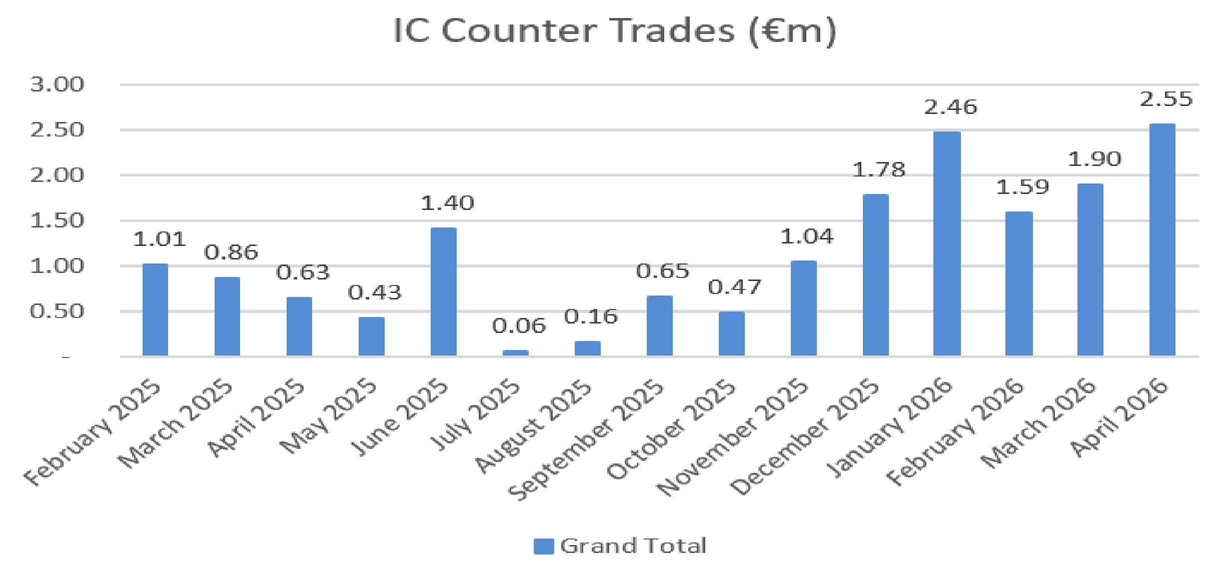

Figure 9 Interconnector Countertrade Cost Trend

The TSOs rationalise this step change in costs from November 2025 to increased system security requirements to counter trade Interconnector exports from that point. This increased requirement subsequently resulted in the introduction of a new Ireland and Northern Ireland System Stability TCGs being published in January 2026 as outlined below.

Ireland & Northern Ireland	Maximum Total System Load Rejection** (from Large Energy Users & Interconnector Exports) not to exceed 900 MW. This insecurity threshold is likely to restrict exports on the interconnectors, with SO-SO trades used to manage this constraint.	System Stability

It is forecast that this increased requirement will persist if not grow for the full duration of the 2026/27 tariff year. As a result, we have projected the Imperfections costs for countertrading from the last 6 months from November 2025 to April 2026 up to a 12-month range and forecasted this Imperfections cost requirement for the 2026/27 tariff year.

4.2.3. Dispatch of pump storage units

Pump storage units are mostly dispatched in pump mode overnight, to facilitate more priority dispatch generation on the system and minimise levels of curtailment for the TSOs to remain compliant with SEM-11-062 or to support with local voltage security requirements to maintain compliance with published Operational Security Standards. During the day, the units are often kept at their minimum generation levels, to provide positive dynamic reserve, replacement reserve or ramping margin reserve. This running profile is different than the profile that clears in the Day-Ahead market and subsequently differs from their Physical Notifications (PNs) in the Balancing Market. Thus, there are high CPemiums and CDiscounts paid by the market to pump storage units. Plexos cannot capture the pump storage unit offer prices, thus a provision of €18.97m is included in the supplementary modelling. The provision is based on 10/12's of the actual CPremium and CDiscount payments that pump storage units received in the last 12 months from the 1st of May 2025 until the 30th of April 2026. This accounts for the fact that the full pumped storage site is scheduled to take a simultaneous outage of all units for 2 months within the 2026/27 forecast horizon.

4.2.4. Constrained wind and solar

Wind/solar is currently not paid for curtailment in SEM; however, it is paid for constraints. As the market settlement outcome of wind/solar constraints is not catered for through the PLEXOS model, we have included a provision of €44.25m within the supplementary modelling. This figure is based on the actual Cdiscount that wind/solar participants received in the last 12 months from the 1st of May 2025 until the 30th of April 2026.

4.2.5. Energy imports for units in system services modes

Modification *13_19* was passed to allow for the remuneration of energy consumption for units that are dispatched by the TSOs in system services modes. When in system services mode at ≤0MW generation, these units may consume energy that has to be generated elsewhere. This results in Imperfection Charge components being calculated for the participant providing the system service being waived and covered through the Imperfections tariff and a different unit in the balancing market being re-dispatched to cover the increased demand, which may also end up as an additional cost to imperfections.

For this year's submission the TSO's have only accounted for the Imperfections charges waived from the system service provider. As a new system service provider connected in 7-Jan-2026, these costs have increased considerable from that time as seen in the graph below.

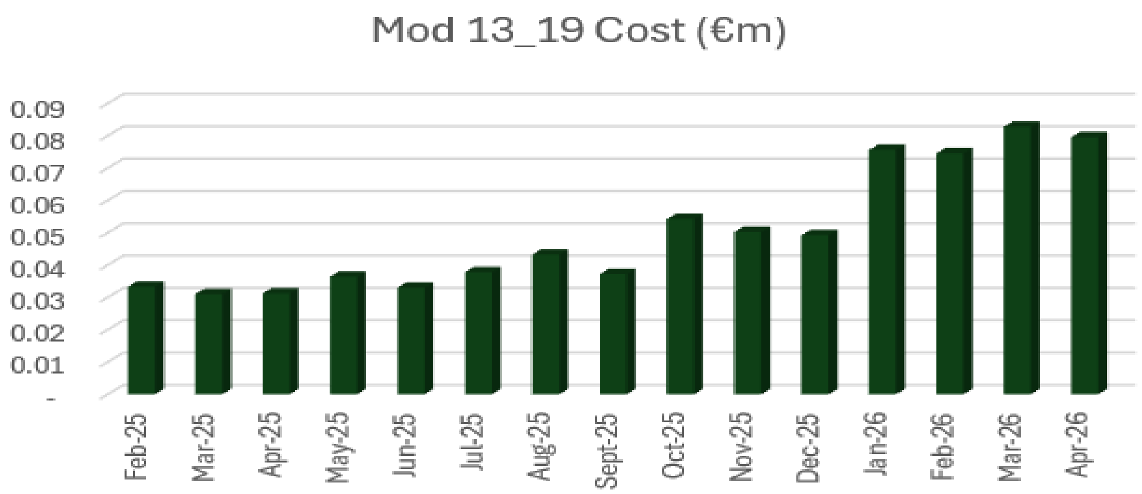

Figure 10 Trading and Settlement Code Mod 13_19 CIMP Cost Trends

As a result, the TSO's have projected out costs from 7-Jan-2026 to the 30th of April 2026 to cover the full 2026/27 tariff period. This amounts to a cost of €0.93m.

4.2.6. Application of historical data in Supplementary Modelling

Through consultation with the RA's and their consultants the TSO's further reviewed their approach to supplementary modelling. It was agreed between all parties that there are limitations in the TSOs' current approach as it just assumes that historical costs from a set range of time are a best placeholder for the future forecast period and this cost is not adjusted for future forecast conditions. However, alternative approaches are not straightforward. The specifics of each relevant supplementary item is addressed below in terms of the review that was carried out and the approach taken for the 2026/27 Imperfections forecast.

System Operator Interconnector Countertrading:

The TSO's countertrade on Interconnectors for one of the following primary reasons.

- To reduce Imports or increase exports to maximise the amount of priority dispatch on the system to comply with the requirements of SEM-11-062
- To increase imports in tight margin periods to keep either jurisdiction out of a system warning or alert condition
- To reduce imports to ensure dynamic stability system security requirements is maintained for the loss of the Tie-Line connecting the Ireland and Northern Ireland transmission systems
- To reduce exports to ensure dynamic stability system security requirements are maintained for the simultaneous loss of Interconnector exports and demand sites.

The conditions in which these criteria are met is highly linked to the hourly availability of variable generator resources. In very high wind and solar conditions there is a much greater likelihood of Interconnector countertrades to meet the requirements of SEM-11-062 or large Interconnector export schedules that may need to be traded back for system stability requirements. In very low wind and solar conditions there is a much greater likelihood of Interconnector trades required to keep Ireland or Northern Ireland systems out of margin warning or alert conditions. In medium renewable conditions it is less likely that countertrading on Interconnectors will be required at all.

As Imperfections forecasting is required to take place looking at 7 months to 19 months ahead of time, there are no accurate long term weather forecasts available to determine the trading period availability of renewable generator sources in the 2026/27 Imperfections forecast horizon. As a result, the TSO's view is that recent trends in Imperfections costs for Interconnector countertrading is the best approximation to predict future Imperfections costs for this requirement for the 2026/27 tariff year.

Instead of the previous year's approach in which the most recent 12-month costs were used to forecast future costs for the tariff year ahead, this year, the TSO's have instead projected out the cost of the last 6 months of Interconnector countertrading Imperfections costs from November 2025 until April 2026 to forecast the cost of this requirement for the full 2026/27 tariff year.

Due to the demand growth of large energy users on the Irish transmission system there has been an increased requirement to countertrade on Interconnectors to reduce exports in order to ensure dynamic stability system security requirements are maintained for the risk of the simultaneous loss of Interconnector exports and demand sites since November 2025. This has resulted in a step change in Imperfections costs for Interconnector countertrades since November 2025. This system security requirement is forecast to persist throughout the 2026/27 forecast horizon and hence this was the reason what this date range of historical costs were used to forecast future liabilities.

Dispatch of Pumped Storage units

The TSO's generally dispatch pump storage units away from their market position in line with operational scheduling tools for the following reasons:

At Night;

- To maximise the output of priority generation resources to comply with SEM-11-062
- To manage local area network voltage support requirements

At Daytime;

- To ensure there is sufficient pumping available at night to maximise the output of priority generation resources to comply with SEM-11-062
- To ensure there is sufficient dynamic upward reserve, replacement reserve and ramping margin reserve dispatched on the system, making use of the technologies highly flexible technical characteristics

This requirement to dispatch pump storage units away from their market position is also heavily linked to the availability of renewable generation resources across the 2026/27 forecast horizon. If there is high availability of renewable generation resources especially during low load night valley periods, operational schedulers ensure maximum pumping is available at night to maximise the output of priority dispatch units in compliance with SEM-11-062. To do this, operational schedulers might also choose to generate more heavily during the higher load periods the day before at the expense of other in merit units to ensure this maximum pumping capability is made available. Both actions generate significant Imperfections costs. In very low renewable availably periods and especially during periods in which large Dublin conventional generators are also unavailable, pumped storage units are also dispatched away from their market position to provide very quick reserve capability during low margin periods and to provide voltage support through the wider Dublin region at night.

As with interconnector trading, the forecasting of dispatch of pumped storage units is challenging as it takes place 7 months to 19 months ahead of time, and there are no accurate long term weather forecasts that can help us infer same in the 2026/27 Imperfections forecast horizon. As a result, the TSO's view is that recent trends in Imperfections costs for pump storage units is the best approximation to predict future Imperfections costs for this requirement for the 2026/27 tariff year.

Instead of the previous year's approach in which the most recent 12-month costs were used to forecast future costs for the tariff year ahead, this year, the TSO's have instead only forecast 10/12 of this cost from the 1st of May 2025 until the 30th of April 2026 for the 2026/27 tariff year due to a scheduled simultaneous 2 month outage of all four generators as per the currently scheduled generator committed outage programme. During periods of partial unit outages of this site the TSO's still believe Imperfections costs will be incurred to the levels seen in the previous 12 months and therefore these periods remain factored into the costs.

Constrained wind and solar

In line with the SEM-11-062 requirements, the TSOs dispatch down wind and solar sites in compliance with the published Operational Security Standards. This requirement becomes a lot more prevalent during periods of high renewable availability and during periods of high outage activity on the Transmission Network.

As Imperfections forecasting is required to take place looking at 7 months to 19 months ahead of time, there are no accurate long term weather forecasts available to determine the trading period availability of renewable generator sources in the 2026/27 Imperfections forecast horizon

In our Imperfections PLEXOS model, availability profiles for renewable sites are applied equivalently to the overall percentage availability of these sites in a period of actual data from the 1st of February 2025 until the 1st of February 2026. This is considered by the TSOs to be a much more effective approach than using a random profile generator in the absence of accurate long term weather forecasts. This time period was chosen for a number of reasons as follows;

- The TSOs believe it is very important for Imperfections forecast accuracy that a link is maintained between renewable availability, demand and Interconnector profiles in line with recent market clearing outcomes
- This time period contained a full year of operational data of the new Greenlink Interconnector
- This combined input formed an essential building block of the PLEXOS forecast model and it had to be applied to the tool early in the process to meet agreed Imperfections forecast timelines.

The actual availability profiles for this time range is applied to the 2026/27 Imperfections forecast model scaled up to the new installed capacity of wind and solar sites forecast to be connected throughout the 2026/27 Tariff year.

The Transmission Outage Programme has an equally significant influence on the amount of dispatch down of renewable generation in the 2026/27 tariff year. Equally, as Imperfections forecasting is required to take place looking at 7 months to 19 months ahead of time, transmission outage programmes covering this period are in their infancy and are not accurate enough to be applied to the Plexos forecast model. As a result, a Transmission outage proxy methodology is applied to the Plexos constrained model as outlined previously in this document. This methodology is applied to determine an estimated overall Imperfections cost for counterbalancing actions required by conventional generation units to account for the dispatch down of renewables for transmission restriction reasons over the full course of a Transmission Outage Programme. The TSOs do not however, expect the volume of dispatch down as modelled in the PLEXOS model to reflect actual dispatch down levels which cannot be determined definitively due to the unavailability of these two sources of key input data.

The TSOs' view is that recent trends in Imperfections costs for wind and solar constraints taken from the 1st of May 2025 until the 30th of April 2026 is the best approximation to predict future Imperfections costs for this requirement for the 2026/27 tariff year. Through engagements with the RAs and their consultants it was agreed that there is a high risk that these costs will be understated due to the projected increase in installed capacity of wind and solar sites throughout the 2026/27 tariff year. Although this is probable, the

TSO's view is that this is not definitive. If newly installed wind or solar are connected in regions of the network that are well connected and not subject to significant transmission outage activity or experiences low renewable availability during outage activity, then increased Imperfections costs would not be observed. As overall wind and solar constraint Imperfections costs are highly variable year on year, heavily linked to availability and transmission outage conditions, these costs cannot be correlated to the overall installed capacities of these technologies connected to the grid. Therefore, in the absence of a justifiable scaling methodology to be applied to the recent actual 12 months of wind and solar constraint Imperfections costs, the TSO's propose to use this actual data as a proxy forecast for 2026/27 wind and solar constraint Imperfections costs noting that any differences will be managed through the K-Factor process.

Through consultation with the RA's and their consultants it was also posed to the TSOs' why the Imperfections costs of the date range from which the renewable availability profiles was sourced was not used to approximate Imperfections costs for the 2026/27 forecast horizon. The TSOs' view is that this input is being applied to a 2026/27 forecast model that has considerably different underlying conditions from the system conditions that were experienced during the equivalent date range from the 1st of February 2025 until the 1st of February 2026. As a result, the resultant imperfections costs for wind and solar constraints in this forecast model would be vastly different from actual costs that occurred in this sample date range. The TSO's contend that taking the most recent 12-months of Imperfections costs available from the 1st of May 2025 until the 30th of April 2026 will approximate 2026/27 market outcomes more closely and therefore is the source of data used by the TSOs for this Imperfections forecast submission while noting its limitations.

Energy Imports for Units in System Service modes

Much of the energy import costs for units in system service mode can be attributed to wind farm units providing system services under 0 MW wind conditions and to synchronous condensers providing inertia services to the grid. As Imperfections forecasting is required to take place looking at 7 months to 19 months ahead of time, there are no accurate long term weather forecasts available to determine the trading period availability of renewable generator sources in the 2026/27 Imperfections forecast horizon. As a result, the TSO's view is that recent trends in Imperfections costs for energy imports for units in system service mode is the best approximation to predict future Imperfections costs for this requirement for the 2026/27 tariff year.

Historically the TSO's projected Imperfections costs for this component as being the market imbalance price to serve this increased load over the previous 12-month period. This approach assumed a full pass through of these costs to Imperfections. On review the TSO's believe this approach will likely over-estimate this requirement as the level of costs that would be passed through to Imperfections for this requirement would not be definitive and would depend on the market conditions at the time.

For this year's analysis the TSOs concentrated on the historical Imperfections charges waived from system service participants from the 7th of January 2026 and the 30th of April 2026. On the 7th of January 2026 a new system service provider entered the market and increased the cost requirement for this component.

It is assumed that this new system service provider will be dispatched to provide inertia services for a significant period of 2026/27 and as a result the costs experienced in the last four months are forecast to persist throughout 2026/27. As a result, the TSO's propose to forecast this cost projected over a 12-month period to approximate Imperfections costs for this component for the 2026/27 tariff year. There is a risk that increased costs on forecast may occur due to the counterbalance of other generation sources required to meet this extra load but the TSO's believe this will be marginal and expect any increased costs should they arise would be manageable through the K-Factor process.

Summary

The TSO's acknowledge that each discrete estimation approach outlined above may not, in isolation, accurately predict the actual outturn cost component that it seeks to predict. As noted previously, it is not the TSO's intention to accurately forecast Imperfections costs on a component basis given the unavailability of key input data in a forecast horizon 7 to 19 months ahead of time. The TSO's optimise this process to produce an accurate as possible overall Imperfections cost forecast for the tariff year in question and the forecasting approach taken for each of the components above should be considered in this context.

Our strong backcast results are evidence of the power of our holistic imperfections modelling. The backcast, which is validated annually through the application of actual data passing through the process ex-post and is reported on this year through the 2024/25 outturn report which accompanies this report, shows a very strong correlation with actuals (as have previous backcast analyses).

4.3. Clean Energy Package (CEP) Article 13(7)

We seek a provision of €141m for potential payments to participants under Article 13(7) of Regulation (EU) 2019 / 943, noting that the SEMC decision SEM/22/009 is subject to a judicial review process in Ireland[14] . This provision includes €98m for historic costs relating to under-allowance of historic liabilities[15] as well as re-estimation of historic liabilities per our modelling approach outlined below, as well as 43m for 2026/27.

This provision is sought to ensure sufficient funding to meet any potential liability, without prejudice to the ongoing judicial review process. No payments would be made until the legal process is finally concluded and there is a regulatory approved calculation methodology and payment mechanism in place. We will further engage with the RAs regarding implementation of any payment mechanism.

Key assumptions regarding this provision have been discussed with the RAs and include:

- Compensation for constraint and curtailment volumes from 01 Jan 2020 to 30 Sep 2027, up to market price level (to the extent not already funded by 2024/25 and 2025/26 Imperfections Charges).
- Any interest, finance and implementation costs, as well as any amounts that may be recovered from intermediaries, have not been included.
- Forecast based on a "first order" approximation.

We note the following matters regarding the forecasting of this provision:

- The forecast is based on an average monthly run based on actual data from the 1st of January 2020 until the 30th of April 2026. The levels of dispatch down on the system over the last three years have increased substantially since the preceding period back to 2020. Accordingly, the current approach has the risk of underestimating the potential payments for 2026/27. Basing a run-rate on average data over the past 3 years would better reflect future potential payments.

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[14] High Court [2023] IEHC 620: https://www.courts.ie/acc/alfresco/33acac75-8f1f-4c5e-8078-7303630c4ff7/2023_IEHC_620.pdf/pdf#view=fitH

Supreme Court [2025] IESC 1: https://www.courts.ie/viewer/pdf/bb9de1e0-4a49-4cce-b67d-e210126b69fb/[2025]_IESC_1.pdf/pdf#view=fitH

[15] Per SEM-25-053, only €37m in relation to forecast 2025/26 costs was provided, whereas €54m for additional historical liabilities was not provided. The €98m request for historical potential liabilities in this submission reflects the an updated forecast of the potential liabilities incurred before FY26/27.

4.4. Interconnector Net Transfer Capacity Restriction

Since September 2021, the TSOs periodically implemented Net Transfer Capacity (NTC) reductions on the SEM-GB interconnectors in order to maintain security standards. These reductions restricted flows from SEM to GB during certain periods.

Moyle Interconnector Ltd. subsequently sought compensation in respect of these actions which resulted in an arbitration process which commenced in early 2024 and resolved in July 2024, with a final determination issued in December 2024 to an amount of €26.8m.

We understand that EirGrid Interconnector DAC (“**EIDAC**”) is likely to raise a claim in respect of compensation for NTC reductions imposed, in the context of SEM operations, by EirGrid plc (as TSO) on the East West Interconnector (“**EWIC**”).

In light of same, we are of the view that provision should be made in the 26/27 imperfections charge pertaining to same amounting to €29.88m.

In December 2025, the SEMC confirmed that the recovery mechanism of NTC compensation should be through the Imperfections Charge. A modification to the Trading & Settlement Code is being progressed to facilitate this approach. The inclusion of NTC-related costs within the 2026/27 Imperfections Charge forecast is based, without prejudice to the T&SC Modification process, on the assumption that the relevant TSC modification will be approved and implemented prior to the start of the tariff year. If the TSC modification is not approved, is materially amended, the value of the costs included may be subject to amendment.

The €56.68m revenue requirement included in the 2026/27 Imperfections Charge forecast relates to recovery of historic NTC compensation costs. Additional costs arising in respect of NTC reductions from future actions are currently expected to be limited; where such costs arise, that they would be addressed through the applicable K-factor reconciliation processes, in accordance with the Trading and Settlement Code.

5. K Factor Submission

The K Factor adjusts for previous Tariff Years under or over recovery.

The calculation of the Imperfections K Factor for inclusion in the 2026/27 tariff is made up of three elements, the Actual Y-1 K factor, the Estimated within-year K factor and the estimated interest associated with the Market Working Capital Credit Facility (MWCCF). These are captured in the table below:

Description	€m
Actual Y-1 K Factor - 2024/25 K is an Over recovery	5.56
Estimate within Year K Factor - 2025/26 K Factor forecast Over Recovery	9.46
Forecasted MWCCF Interest 2025/26	(1.8)
Total Forecast Imperfections K Factor for inclusion in the 2026/27 tariffs (net Over Recovery)	13.22

The Y-1 K Factor 2024/25, of €5.56m over recovery, is after CEP funds collected of c. €158.0m have been ringfenced. These funds have been ringfenced in separate bank account by the TSO in line with the Trading and Settlement Code. The Estimate within Year K-Factor 2025/2026, over recovery of €9.46m, has also been calculated such that CEP funds collected through the tariffs have been ringfenced in a separate bank account.

The Market Working Capital Credit Facility (MWCCF) was drawn upon from February 2025. As per Section B.13.2 of the Trading & Settlement code the interest associated with this facility is recovered through Imperfections Charges. The forecasted interest for 2025/26 is €1.8m.

For this period a **net Over Recovery of €13.22m** is anticipated and thus will be **subtracted from** the imperfections forecast for 2026/27.

5.1. Actual Y-1 K Factor 2024/25

The actual K-factor arising for 2024/2025 was lower than forecast, an under recovery of €161.0m[16]. The delta between the forecast 2024/2025 K-factor and the actual 2024/2025 K-factor results, as well as taking into account interest costs on the Market Working Capital Credit Facility (MWCCF), yields an over recovery of €5.56m.

The MWCCF has been drawn upon since February 2025. As per Section B.13.2 of the Trading & Settlement code the interest associated with this facility is recovered through Imperfections Charges. The Interest incurred related to 2024/25 was €0.5m.

[16] The actual outturn over/(under) recovery for 2024/25 (actual k-factor arising in year), of €161.0m under recovery, excludes CEP funds collected of c. €158.0m. These have been ringfenced in separate bank account by the TSO in line with the Trading and Settlement Code.

Description	€m
Actual outturn over/(under) recovery for 2024/25 (actual k-factor arising in year)	(161.0)
An estimated under recovery of €167.06m was included in calculating the tariff for 2025/26, this must be taken into account to arrive at what is left to be taken into account in setting the k factor for 26/27	167.06
MWCCF Interest 2024/25	(0.5)
2024/25 k-Factor to be included in 2026/27 tariff	5.56

5.2. Estimate within Year K Factor 2025/26

The Estimated within year (Y) K Factor (2025/2026) is a forecast of the financial position, as reflected in the accounts, as at the end of September 2026. This must take the following into consideration:

- The actual imperfections costs against the forecast and forecast trend to year end;
- It is net of the CEP funds being collected;
- Any resettlement costs from previous periods (M+13 etc.) that fall within the period (noting the caveat in section 1.2)

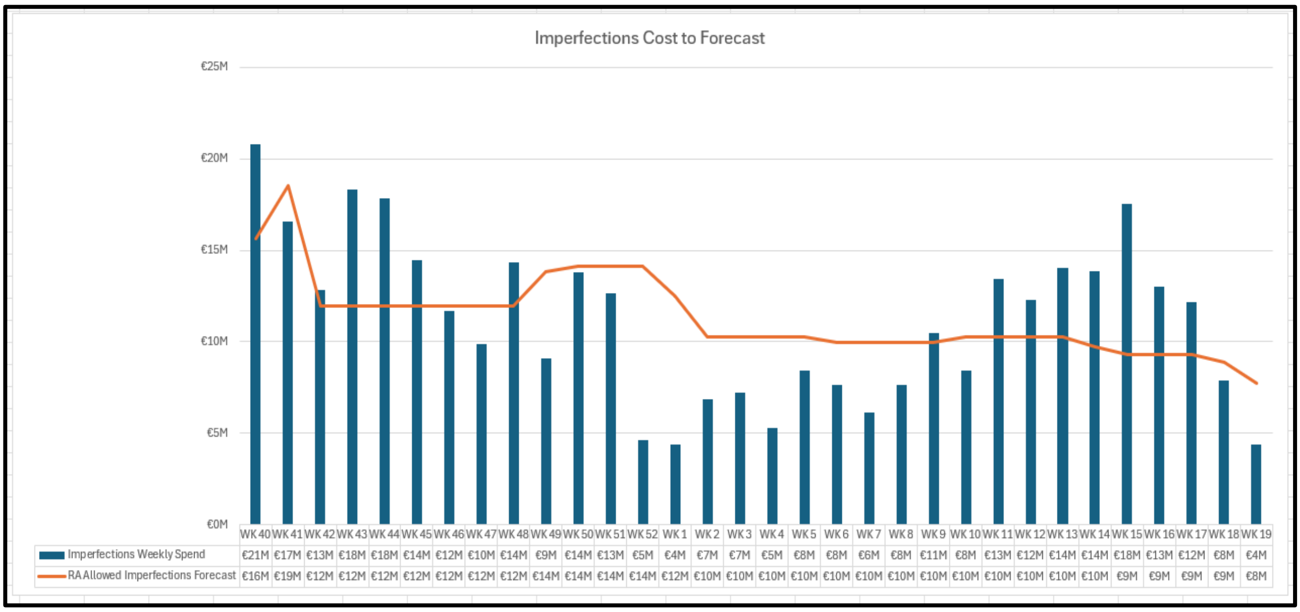
Imperfections Costs

There are two main factors influencing the within year forecast K factor for 2025/2026 - that is the estimated outturn expenditure against forecast and the estimated outturn revenue against forecast.

Overall there has been close correlation seen between our Imperfections forecast and actual costs on the system for the first 7.5 months of the 2025/26 Financial Year with an underspend against forecasted Imperfections of ~€8 million. Where costs have deviated, they have largely been counterbalanced (or are expected to do so by the end of the year). For example, increased costs on forecast arising while satisfying the Northern Ireland (NI) Security of Supply dynamic stability requirements in a cost-effective manner during prolonged forced Generator outages in the region, was then counter balanced by a period of reduced fuel prices on forecast for the first quarter and periods of the second quarter of 2025/26. For the latter periods of the second quarter however, fuel costs have since increased substantially on forecast and are expected to remain at this level for the remainder of this tariff year. As a result, it is expected that the underspend seen year to date will be offset and Imperfections will return in line with RA approved forecast costs for the 2025/26 tariff year.

YTD Details	01/10/25 - 09/05/26
YTD Budget	€363.21 million
YTD Imperfection Costs (-OSC)	€355.21 million
Sum of Variance	-€8.00 million
Variance %	-2.2%
Annual Imperfection Budget	€569.81 million

The week-to-week volatility seen in the performance of Imperfections costs to RA approved spend as seen in the figure below is an anticipated feature of the TSO's Imperfections forecasting principles.



	WK 40	WK 41	WK 42	WK 43	WK 44	WK 45	WK 46	WK 47	WK 48	WK 49	WK 50	WK 51	WK 52	WK 1	WK 2	WK 3	WK 4	WK 5	WK 6	WK 7	WK 8	WK 9	WK 10	WK 11	WK 12	WK 13	WK 14	WK 15	WK 16	WK 17	WK 18	WK 19
Imperfections Weekly Spend	€21M	€17M	€13M	€18M	€18M	€14M	€12M	€10M	€14M	€9M	€14M	€13M	€5M	€4M	€7M	€7M	€5M	€8M	€8M	€6M	€8M	€11M	€8M	€13M	€12M	€14M	€14M	€18M	€13M	€12M	€8M	€4M
RA Allowed Imperfections Forecast	€16M	€19M	€12M	€12M	€12M	€12M	€12M	€12M	€12M	€14M	€14M	€14M	€14M	€12M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€10M	€9M	€9M	€9M	€9M	€8M

- **Estimated Outturn Expenditure** = €569.81m [Original - Expected Outturn Spend, €569.81m - €569.81m = €0m over/under recovery)

- **Estimated Outturn Revenue** = €799.7m [Original + 24/25 k factor - Expected Outturn Revenue, €606.81m + €183.43m - €799.7m = €9.46m over recovery)

This would yield an estimated potential over recovery in 2025/2026 of **€9.46m** (€0m + €9.46m)

Resettlement

Bar the note flagged in section 1.2, no other notable resettlements expected.

Summary

Estimated Outturn 2025/26 = (€5.56m + €9.46m - €1.8) = €13.22m over recovery

Total Forecast K Factor to be applied in 2026/27

The total forecast K is an **over** recovery of **€13.22m** which will be subtracted from the Imperfections forecast revenues.

6. Imperfections Charge Factor

Under the current SEM arrangements, as detailed in the Trading and Settlement Code, RA/ SEMC approval is required for the Imperfections Charge Factor (FCIMP).

The intent of this is to enable EirGrid and SONI, when it becomes evident within a given year that the Imperfections Charge is not providing the adequate recovery or is over recovering the anticipated costs, to seek approval from the RAs to increase or decrease the factor. This allows them to increase or decrease the Imperfections Charge to a level which adequately recovers the costs, without requiring an amendment to the underlying approved forecast requirement. This would allow the revenues to be recovered within the given year and thus minimise the K Factor for the relevant Tariff Year.

In accordance with Section F.12.1.1 (b), we are now seeking the approval for the Imperfections Charge Factor to be set to 1 for the period of 1 October 2026 to 30 September 2027.

Appendix 1: Trading and Settlement Code Extract

The relevant Trading and Settlement Code sections are shown in Table 8 below.

F.12.1	Setting of Imperfections Charges parameters
F.12.1.1	The Market Operator shall report to the Regulatory Authorities at least 4 months before the start of the Year, proposing values for the following parameters to be used in the calculation of Imperfections Charges for that Year: (a) The Imperfections Price (PIMPy) in €/MWh for Year, y; and (b) The Imperfections Charge Factor (FCIMPγ) for each Imbalance Settlement Period, γ, in Year, y.
F.12.1.2	The Market Operator's report must set out any relevant research or analysis carried out by the Market Operator and the justification for the specific values proposed. The report may, and shall if so requested by the Regulatory Authorities, include alternative values from those proposed and must set out the arguments for and against such alternatives.
F.12.2.1	The purpose of the Imperfections Charge is to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Fixed Cost Payments and Charges, any net imbalance between Trading Payments, Trading Charges, Capacity Payments and Capacity Charges over the Year, with adjustments for previous Years as appropriate.

Table 8 Extract from Trading and Settlement Code Part B Related to Imperfections Charges Parameters

Appendix 2: PLEXOS model assumptions

We use PLEXOS to forecast constraint costs. PLEXOS is a production cost model that can produce an hourly schedule of generation, with associated costs, to meet demand for a defined study period. The main categories of data that feed into the PLEXOS model are summarised below:

Key assumptions used in PLEXOS model

Detailed below are the key assumptions used in the PLEXOS modelling process:

Feature	Assumption
Study period	The study period is 01/10/2026 to 30/09/2027
Data freeze	The TSOs strategically employed a data freeze in a manner that optimised the most up to date data available to approximate inputs and remain within Imperfections process timelines. The origin and timings of specific data sources used for key input data is identified throughout this document
Generation dispatch	Two hourly generation schedules are examined: • one schedule to represent the dispatch quantities (constrained) • the other to represent the market schedule quantities (unconstrained)
Study resolution	Each day consists of 24 trading periods, each 1 hour long. A 6-hour optimisation time horizon beyond the end of the trading day is used to avoid edge effects between trading days.
Demand	
Load	The forecasted demand was derived from the median scenario of the All-Island Resource Adequacy Assessment (AIRAA) 2026-2035. NI total load and IE total load are represented using individual hourly load profiles for each jurisdiction.
Load representation	Load Participation Factors (LPFs) are used to represent the load at each bus on the system. LPFs represent the load at a particular bus as a fraction of the total system demand.
Fixed Load	Fixed load refers to the load consumed by industrial customers, that is assumed to have a relatively constant profile. This is separated out from the overall system load, so that it is not profiled, and added back on to the system load following the load profiling exercise described above. No increase in Fixed Load is forecasted for 26/27.
Embedded Solar	Forecasted embedded solar levels are based on projections of current installed levels gathered by the DSOs. It is accounted for in our model by profiling the embedded solar and reducing the demand by this profile on an hourly basis.
Generator house loads	These are accounted for implicitly by entering all generator data in exported terms.
Generation	

Feature	Assumption
Generation resources	Generation resources are based on the All-Island Resource Adequacy Assessment (AIRAA) 2026-2035, REMIT data and the schedule of connecting generators held by EirGrid and SONI as of March 2026.
Fuel and carbon prices	Fuel/carbon prices for 2026/27 are based on the long-term fuel forecasts from Thomson-Reuters Eikon and the US Energy Information Administration as of 30th April 2026.
Production costs	Calculated through PLEXOS. The inputs to PLEXOS were based on analysis of actual bids submitted between 1st March 2025 and 28th February 2026. 1. Fuel/carbon cost (€/GJ) 2. Piecewise linear heat rates (GJ/MWh) 3. No-Load rate (GJ/h) 4. Variable Operation and Maintenance Costs (€/MWh) 5. Gas Transportation Charges (GTC) (€/GJ) for gas units 6. Start-up costs (€)
Generation constraints (TOD)	Based on the data Technical Offer Data (TOD) in the SEM, the following technical characteristics are assumed: 1. Maximum Capacity 2. Minimum Stable Generation 3. Minimum up/down times 4. Ramp up/down limits 5. Cooling Boundary Times 6. Inertia Contribution
Generator scheduled outages	2026 and 2027 maintenance outages are based on the published Committed Outage Programmes for 2026 and 2027 as of 1st May 2026.
Forced outages	Forced Outage Rates and Mean Times to Repair is based on analysis on historic outage data from December 2024 to December 2025. The specific occurrence of a forced outage of a generator in the PLEXOS model is determined using a random number generator.
Hydro generation	Hydro units are modelled using daily energy limits. Other hydro constraints (like drawdown restrictions and reservoir coupling) are not modelled. We assume in our models that Hydro units follow PN in all instances.
Pumped storage	We have modelled pumped storage by analysing day-ahead market results and actual dispatch over Tariff Year 24/25. Using day-ahead market results for the Unconstrained model and actual dispatch for the Constrained model, we established the average hourly dispatch across all units. From this we created a daily dispatch profile for both models consisting of 24 points each, one for each hour in the day. Averaged values were converted to TOD compliant values to ensure that the profiles were physically feasible. The 24-hourly profiles are strictly adhered to in PLEXOS, with no optimisation done by the software.

Feature	Assumption
Priority dispatch generation	Wind and solar generation resources are based on current installed capacity plus forecasted new connections. We base the output for these on actual availability profiles from 1st February 2025 to 1st February 2026 All other priority dispatch units are modelled to follow their PN at all times.
Security constraints	Since a DC linear load flow is used, voltage effects and dynamic and transient stability effects will not be captured. System-wide and local area constraints have been included in the model as a proxy for these issues. This is consistent with how generation is scheduled on the power system.
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.
Interconnector flows	Interconnector flows with Great Britain (GB) are forecast based on actual flows delivered from 1st February 2025 to 1st February 2026. Metered data is used for the constrained model and actual schedules were used in the unconstrained model. Variances in interconnector schedule and delivered energy is generally due to trading activity, which is captured through this approach. We have applied a 200 MW export cap on all interconnectors in the constrained model in line with our assumed average system security requirement forecast for 2026/27.
Batteries	Batteries have been modelled implicitly. Following the go-live of SDP02 on 12th November 2025, batteries can now submit negative PNs and are set to follow PN. The TSOs occasionally have to diverge from this approach for system security reasons, such as the conservation of energy for anticipated tight margin periods or the cap applied to charging since the introduction of new System Stability TCGs. We analysed their market behaviour and dispatched quantities and determined average values of discharge over the peak and charge during the night load valley. The average discharge value is subtracted from the peak, and the average charge value is added to the night valley. • Unconstrained: o Peak 17:00-19:00 IE: 105 MW NI: 11 MW o Nadir 00:00-05:00 IE: -56 MW NI: -10 MW • Constrained: o Peak 17:00-19:00 IE: 57 MW NI: 6 MW o Nadir 00:00-05:00 IE: -38 MW NI: -7 MW The TSOs are exploring explicitly modelling batteries in the PLEXOS model when Long Duration Energy Storage comes into scope of the Imperfections Forecast.
Operational Pathways to 2030 milestones	Operational Constraints were assumed based on the latest available information as of 1st May 2026. System Non-Synchronous Penetration (SNSP) is set at 75% in the constrained PLEXOS model from Oct 2026. During the year, it is assumed that: • the minimum number of sets All Island is 7 sets,

Feature	Assumption
	• The minimum number of sets in IE is 4, • The minimum number of sets in NI is 2, and; • that the minimum level of inertia is 23 GWs.
Transmission	
Transmission data	The transmission system input to the model is based on data held by the TSOs.
N-1 contingency analysis	Principal N-1 contingencies, based on TSOs operational experience, are modelled.
Transmission constraints	Transmission constraints are only represented in the constrained model. The market schedule run is free of transmission constraints. Transmission outages and the constraints that will arise from them are inherently difficult to model accurately. In the unconstrained model, we use renewable availability data linked to our interconnector and demand data (i.e. from 1st February 2025 to 1st February 2026). In the constrained model, we use the renewable availability data minus the MWh constraint for transmission restriction reasons from the same period. This data is sourced from published renewable dispatch down data on the TSOs website. Generally, every endeavour is made with scheduled transmission outages to avoid constraints to conventional generators in low renewable scenarios and minimise constraints to renewable generators in high renewable scenarios. We feel that the most recent constrained renewable data is the best available representation of constraints on the system, as we cannot accurately forecast transmission outages and weather patterns associated with renewable resources 7 months to 19 months ahead of time.
Network load flow	A DC linear network model is implemented in the PLEXOS model.
Ratings	Ratings for all transmission plant are based on figures from the TSOs' database.
Louth-Tandragee tie-line transmission limits	The North-South tie-line is not restricted in the unconstrained SEM-GB model. Tie-Line flow restrictions are modelled in the constrained schedule based on actual maximum flows from 1st March 2025 to 28th February 2026, which on average fell between 450 MW N-S and 200 MW S-N.
System Stability TCGs	As of 12th January 2026, maximum total system load rejection is not to exceed 900 MW. This is accounted for in our constrained model.
Forced transmission network outages	Forced transmission network outages have not been explicitly included in the model. The impact of a random selection of forced transmission outages is implicitly captured in the transmission constraints proxy being used.
Ancillary Services	
Operating reserve	Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled.
Reserve characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.

Feature	Assumption
Reserve sharing	Minimum reserve requirements are applied to each jurisdiction, with the remainder being shared. These requirements are per the current reserve policy as of 1st May 2026.
Other reserve sources	For this forecast DSUs, interconnectors and batteries will also provide reserve in the model.
Inertia	Inertia requirements are modelled as per the published TCG requirements as of 1st May 2026, with adjustments made to the requirement based on connected synchronous condensers. Inertia is rarely binding, with the requirement largely being met indirectly when other system stability TCGs constrain on conventional generators. It is assumed that in a scenario where the current inertia limit is binding, all synchronous condensers will be committed, and so the inertia contribution of those on the system is subtracted from the total inertia requirement in our model.

Appendix 3: Imperfections Cost Drivers

Some of the key reasons why it is necessary for the TSO's to dispatch units away from their market position is as follows.

1. To maintain compliance with the TSOs Operational Security Standards (OSS)

Reserve (Frequency Limits)	Thermal	Voltage	Dynamic Stability
• All Island Operating Reserve Requirement • NI/IRL Minimum Operating Reserve Requirement • NI/IRL Replacement Reserve (OCGT) Limitation • NI/IRL Negative Reserve • Ramping	• North South Tie Line Limit • Various Dublin Must Run • Cork Harbour Export Limit • Outage Management Temporary Must Run	• NI Must Run • Various Dublin Must Run • 400 kV Voltage Management Must Run • Outage Management Temporary Must Run	• Inertia • Rate of Change of Frequency (RoCoF) • System Non-Synchronous Penetration (SNSP) • NI 2 Units Must Run • IRL 4 Units Must Run • AI 7 Units Must Run

Figure 2 Operational Security of Supply Constraints

2. To continue to operate transmission equipment within their standard operating ranges
    - The transmission system might have inherent weaknesses that prevent the system to be run as per the market schedule or
    - The transmission system might have temporary weaknesses due to the presence of transmission outages for connection projects or for network development & maintenance.
3. To balance electrical supply to demand if the market clears long or short.

The price volatility of these TSO actions is heavily influenced by several external factors including.

- Fuel Prices
    - Gas remains the primary source of fuel for electricity generators on the Irish system. Any changes in gas prices have a significant impact on the cost of Imperfections. Gas prices are forecast to take a significant rise in the 2026/27 Tariff year
- Market Participant Bidding Behaviour
    - Prices submitted by Generators that form part of an Operational Constraint group are largely passed through to Imperfections if that unit does not clear in the market.
    - If the costs submitted by the Participant through their Commercial Offer Data (COD) is large, then this will have a significant influence on the volatility of Imperfections Costs
- Generator/Transmission equipment faults
    - For the unexpected loss of any generator, the pool of generators available to satisfy a security of supply constraint is reduced and therefore the cost of satisfying these constraints becomes more volatile and largely passed through to the Imperfections Tariff.
    - The unforeseen loss of transmission equipment creates weaknesses in the system that make it more difficult to securely dispatch the system to market schedules. This leads to increased levels of dispatch down and can result in a significant level of Imperfections Cost.

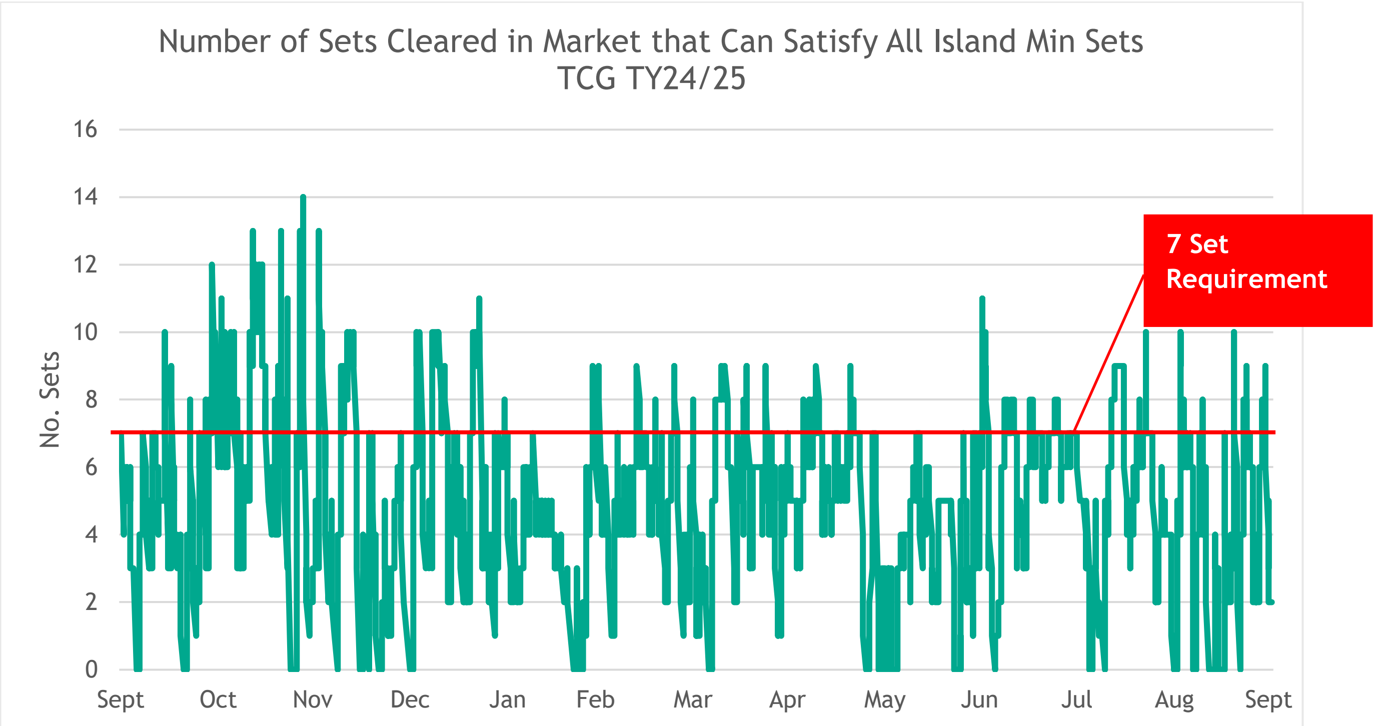
- Renewable generation available capacity & Interconnector Imports
    - There has been a considerable increase in the energy provided by renewables and Imports provided by Interconnectors over the last number of years. At times this can lead to very low market prices and the gap between the market price and the generator price of the unit required to be dispatched on for security reasons is bigger. Although this reduces the overall cost of supplying electricity, very high levels of renewables or Interconnector imports can have a negative impact on Imperfections while there remains out of market system security requirements.
- System electrical demand net of embedded generation
    - Demand growth can have a positive impact on imperfections as the generation required on to meet system security requirements naturally clears in the market and doesn't form part of an out of market action. This is however, subject to no new system security requirements being created to manage the higher load system.

Some of the biggest influences on the volatility of Imperfections costs above including Renewable availabilities, Interconnector Imports and the TSO's assumptions when approximating representative participant commercial offer data is outlined in more detail later in this appendix and appendix 4.

Imperfections costs are lowest when the electricity market clears with sufficient energy and in a way that satisfies the TCGs required for the safe operation of the grid

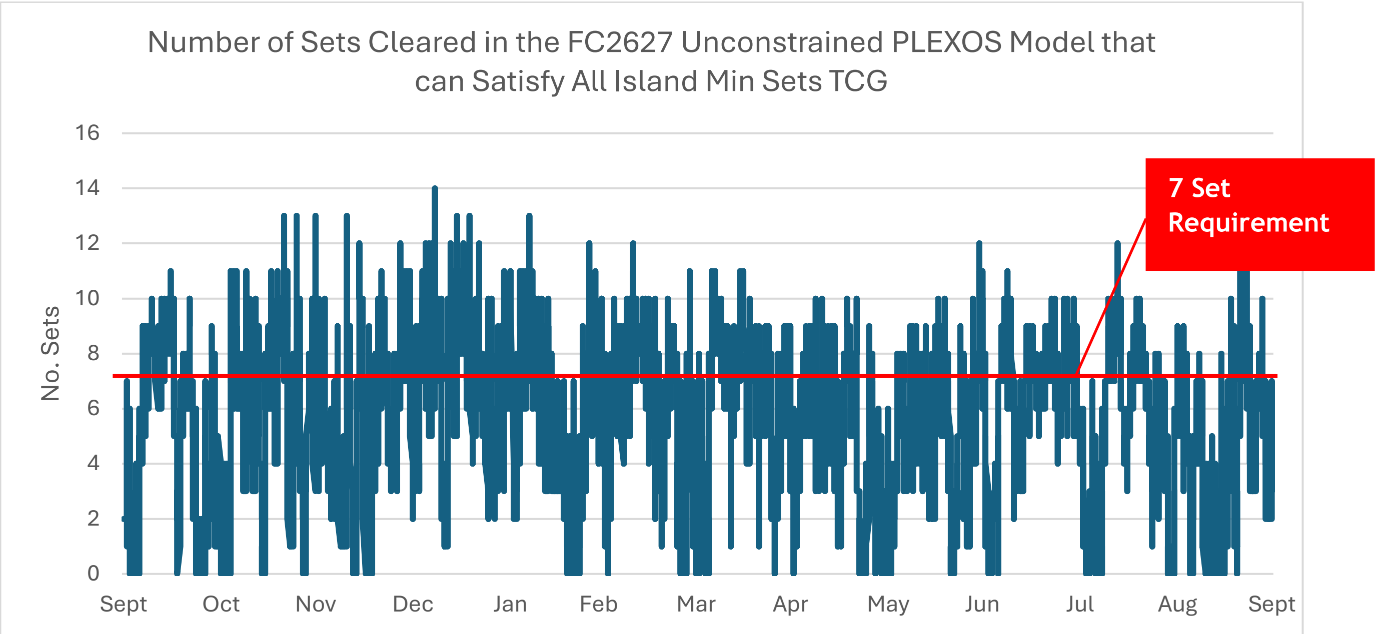
Counterintuitively, this means that periods of high renewable penetration will be expensive from an imperfections cost perspective, while having a low wholesale electricity cost, and periods of low renewable penetration will typically be less expensive form an imperfections cost perspective, with a relatively high wholesale electricity cost.

Outside of periods with exceptional generator outages on the system, the most expensive periods we may see from an imperfections perspective will be high wind, high solar, high Interconnector import days in the summer, which also have a high number of transmission outages and low demand. In such conditions, it's possible that the market doesn't satisfy any TCG, and several conventional generators must be dispatched on to secure the system, at significant imperfections cost.

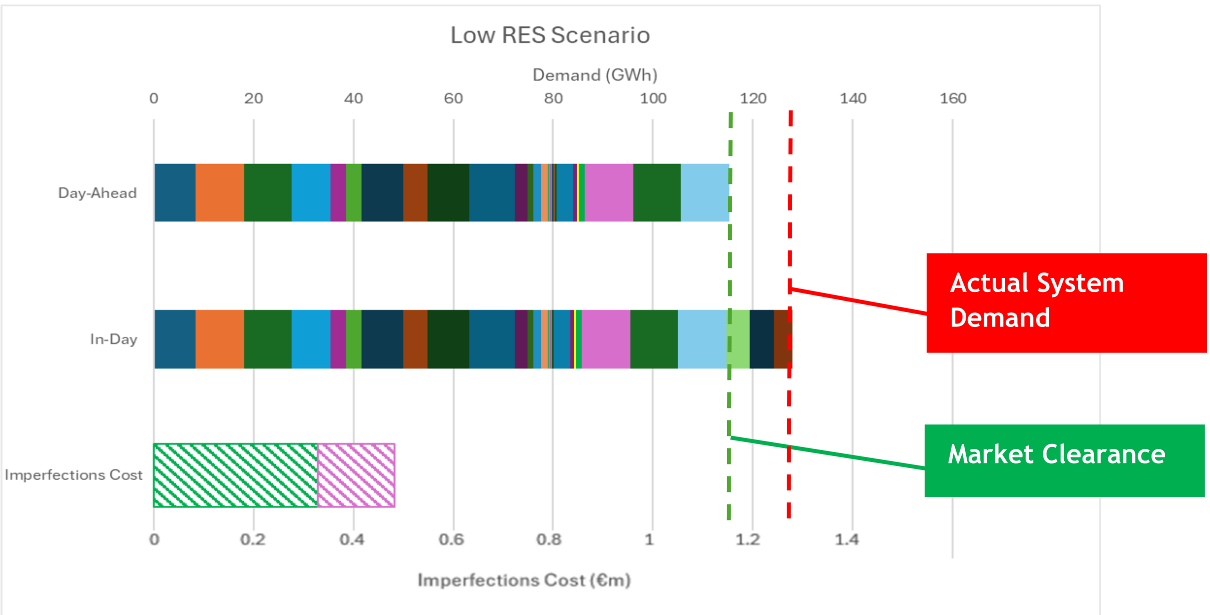


The Day-Ahead market satisfied the All-Island Minimum Sets rule 29% of the time in TY24/25

By way of comparison, in the Forecast 26/27 unconstrained PLEXOS model, the market satisfied the All-Island 7-set rule ~42% of the time. It should be noted that there are various scenarios in which 7 units that technically could satisfy this TCG can't be the 7 sets that end up satisfying the rule in actual operation. One example of this is if all 7 sets that clear are based in IE. In this scenario, 2 sets will need to be constrained on to satisfy the MINNIU, and it may be the case that two of the units that cleared in IE would then need to be constrained off.



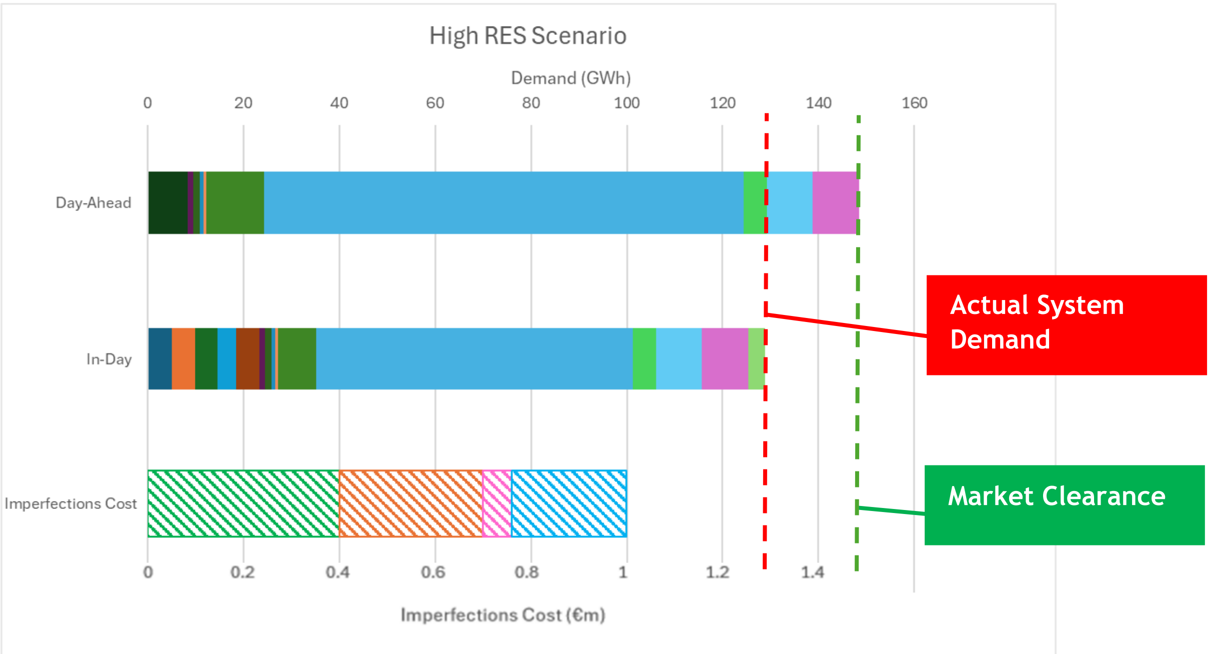
Often, on Low RES days, the market satisfies most system constraints, leading to low imperfections costs. In the below example, there is very low RES-E, and the generation mix is made up primarily of CCGTs, OCGTs, Peakers and interconnector imports. The Day-Ahead market has cleared short of the actual all-island energy requirement. The only deviation necessary from the market outcome was to dispatch on one additional unit in NI to satisfy the MINNIU TCG (2 sets), and to increment some generators to meet the energy required, indicated by the green and pink striped bar below. All other TCGs were satisfied naturally by the market outcome. More complex scenarios are possible, but an example such as this shows how a day with a high wholesale electricity cost may have very low imperfections costs.



Conversely, on high-RES days, the market outcome satisfies fewer system constraints. In the below example, there is very high wind and solar all-island, and the day-ahead market has cleared long (i.e. with more energy that the system needs in that day). As a result, imperfections costs are higher, with numerous conventional units being constrained on to satisfy TCGs. These conventional units will have a minimum stable generation level, and so will displace at least this volume of energy that had cleared in the market, potentially incurring further CDISCOUNT and CPREMIUM costs.

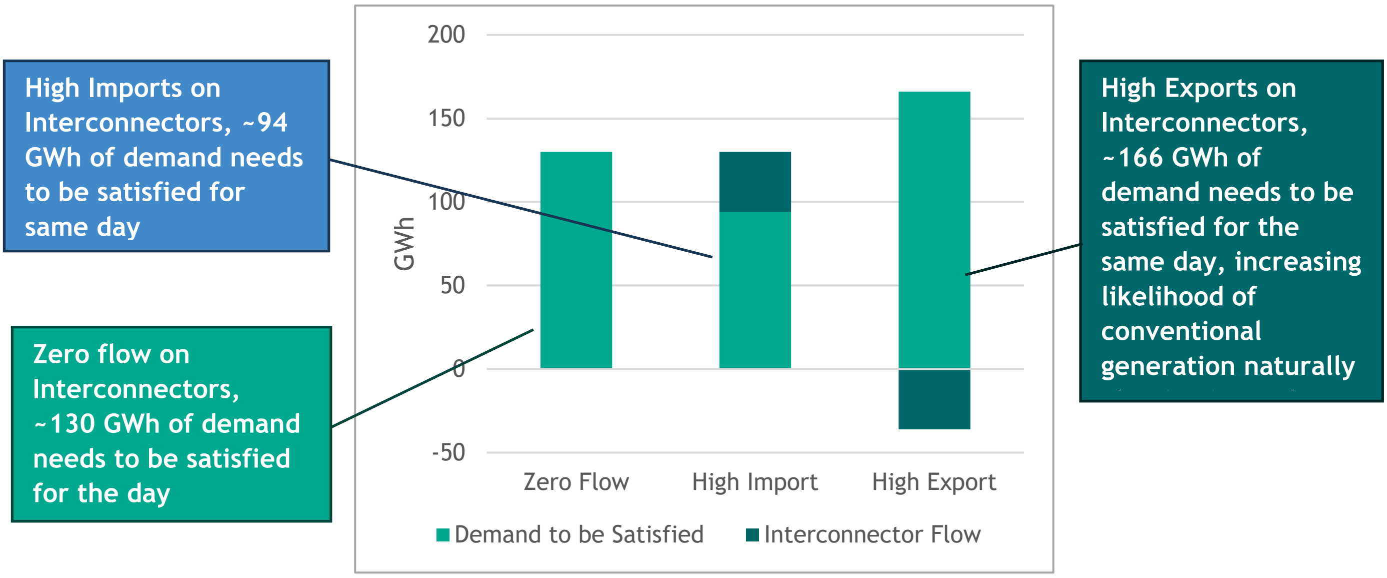
The stacked bar in the below charts are constructed as follows:

- Day-Ahead: this is comprised primarily of high wind and solar availability, river run hydro, one conventional unit clearing in the market and imports on all three interconnectors.
- In-Day: this has a slightly reduced amount of wind and solar due to curtailment on the system, and a number of conventional units dispatched on at minimum generation to satisfy the various system constraints.
- Imperfections Cost: the striped green section indicates the cost of constraining on 2 units in NI to satisfy the MINNIU TCG, the striped orange section indicates the cost of constraining on 4 units in ROI to satisfy the ROImin TCG, the pink striped section indicates the cost associated with constraining on 1 additional unit to bring the all-Island total to 7, satisfying the MIN TRL7 TCG, and the blue striped section indicates the cost associated with not dispatching the conventional unit that had cleared in the market due to thermal constraints on the system.



For the sake of ease of comparison, all interconnectors were considered to be importing fully in both scenarios.

While we predominantly see imports into SEM from GB recently, the direction of flows can have a significant impact on imperfection costs.



Interconnector imports act to increase the cost of imperfections, as there is less energy available for conventional generators to provision for, and so less TCGs are satisfied naturally by conventional generators clearing in the market. Conversely, interconnector exports can act to decrease the cost of imperfections, as there is more energy to be satisfied by the market, which increases the likelihood of TCGs being satisfied without the TSO having to constrain on a conventional unit, and displace energy that cleared in the market. It should be kept in mind, however, that interconnector imports will generally act to suppress wholesale electricity prices by importing energy from an area of lower cost to an area of higher cost.

It should also be noted however that the above trends in relation to increasing Imperfections Costs during high RES availability scenarios and high Interconnector import scenarios are linked to the current set of operational security requirements. High RES availability and increased Interconnection are positive overall for the energy consumer, putting increased downward pressure on the wholesale electricity price. This, coupled with the reduction to a minimum set of operational security requirements in line with the Operational Policy Roadmap, will serve to simultaneously arrest the rising trends in Imperfections costs.

Measurement of Imperfections Cost Drivers

Through consultation with the RA's and their consultants it was investigated if it would be possible to quantify the Cost of each specific Imperfections driver for both looking back at a historical timeframe and through the forecasted Imperfections timeframe. This exercise proved very challenging for the following key reasons

- Scheduling and Dispatch decisions are made in Real Time using Market Management System (MMS) or in a forecast horizon through PLEXOS, both optimisation software packages attempt to find the least cost generation schedule while meeting all system security, network constraint and policy requirements.
- Participants can be dispatched to a particular output away from its market position and incur Imperfections Costs for multiple simultaneous reasons which can also be layered across different ranges of the participants' output.

- MMS or PLEXOS does not report on the reasons it has arrived at a particular scheduling output on a participant level.
- Scheduling and Dispatch is also time bound and subject to participant technical operating characteristics and might be dispatched on/off or away from market position in anticipation of a forecasted future operational security, network constraint or policy requirement based on forecast solar, wind and demand input
- Scheduling and Dispatch is also subject to an All-Island Merit order so an action resulting in a deviation of a unit from market position can incur Imperfections Costs on units of either Jurisdiction regardless of which jurisdiction the action originated from.

Actions include; Transmission outage, Generation outage, generation/demand tripping, jurisdictional operational or national policy

It was therefore concluded that it is technically infeasible to precisely allocate Imperfections cost to a definitive reason. As a result, we have undertaken a workstream to develop and agree on an approximation methodology in which Imperfections Costs can be broadly (not perfectly) mapped to a reason using said methodology. We note that this aligns with a reporting incentive requirement outlined by the CRU in its PR6 Final Determination for EirGrid TSO[17].

EirGrid Price Review SIX – Imperfections Reporting Workstream

As part of the Price Review Six – User Guide – Annex D TSO Incentives, the CRU have tasked EirGrid TSO to significantly expand their reporting capability in terms of Imperfections Costs and dispatch volumes away from Market Position. From the PR6 User Guide section 2.2.2[18]

> *"The aim of the Imperfections & Constraints (I&C) incentive is to encourage EirGrid to take actions to mitigate and reduce imperfection costs by effectively reducing system and network constraints. It incentivises the delivery of these measures through the assessment of their impacts."*

While the CRU has included several metrics within this incentive, it is the reporting metric (number 3 in their paper) which sets out the requirement to

> *"In Year 1 develop a methodology to approximate the reasons for imperfection costs and redispatched volumes. The methodology should be submitted to CRU for approval and should facilitate the TSO's fulfilment of Article 13(4) of the Clean Energy Package[2] and annual ACER surveys. This methodology should subsequently be used when demonstrating benefits of any actions taken by the TSO to reduce or remove constraints or curtailment (Metrics 1&2). Assessment of this metric will take place after Year 1."*

Therefore, after implementation and agreement with the CRU, this methodology would provide a basis of reporting on imperfections cost drivers over time. The intent for the purposes of the TSOs' joint reporting on imperfections costs would therefore be to leverage this methodology for the purposes of explaining the evolution of imperfections costs over time and providing further transparency to the process of imperfections forecasting.

RA and Consultants Quantitative Review of Imperfections Cost Drivers

The RA's and Consultants investigated the TSO's 2025/26 Imperfections forecast model and expanded on the standard TOOT analysis that was carried out by the TSO to trace the root causes of Imperfections

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[17] Section 2.2.2 of PR6 User Guide CRU2025200d_-_Price_Review_Six_-_User_Guide_Annex_D_Performance_Incentives_-_V1.0.pdf

[18] CRU2025200d_-_Price_Review_Six_-_User_Guide_Annex_D_Performance_Incentives_-_V1.0.pdf

Costs themselves and their interactions. This was done by analysing input interactions between the unconstrained and the constrained model in the TSO's 2025/26 Imperfections forecast model. The RA's and Consultants carried out three separate analytic approaches as follows:

- Take One Out at a Time (TOOT)
  - Removing scenario groups one at a time and not in sequence from the fully constrained model and not replacing these with any alternative
- Add One in at a Time (AOT)
  - Adding scenario groups one at a time and not in sequence from the fully unconstrained model
- Bridges
  - Removing scenario groups in a sequential mode, starting from the fully constrained model until reaching the fully unconstrained model

The RA's and Consultants analysis could not determine the quantitative impact of each scenario as different quantitative outcomes were reported whether the scenario was passed through the TOOT, the AOT or in each sequence it was applied in the various Bridge scenarios carried out. The TSO's welcome the analysis however, as it did strongly support the TSO's views on the largest Imperfections Costs drivers for any given year given current Network and Operational Constraint requirements to satisfy system security needs. In the 2026/27 Imperfections forecast model there hasn't been any significant update in the assumed Network, Policy or Operational Constraint Rules that were applied in the 2025/26 Imperfections Forecast model that would change the relative material drivers of Imperfections Costs as determined through the RA's and Consultant analysis.

The RA and Consultant analysis determined the following to be the main drivers of Imperfection Costs for the 2025/26 Imperfections forecast model. The TSO's agree with this determination and advise that a similar outcome would be derived for the 2026/27 Imperfections forecast as outlined below.

Impact Order[19]	Imperfections Cost Driver	TSO Commentary and 2026/27 Forecast Comparison
1	Must Run	• The TSO's agree that the All-Island 7 set Must Run Requirement broken into a 2 set must run requirement in NI and a 4 set must run requirement in IE is one of the biggest drivers in Imperfections Costs. • This same requirement remains in place for the 2026/27 forecast horizon. • In the 2026/27 Imperfections forecast model this operational security requirement was only satisfied ~42% of the time in the unconstrained run, therefore requiring the constrained run to displace market clearing units for the remainder. • This requirement cannot be met by least cost market available generation and has to be satisfied by a select set of generators exhibiting the required technical and locational characterises. The cost of running these specific units are

[19] With 1 being the most impactful

		forecast to rise significantly in the 2026/27 Forecast model correlated to the rise in forecast gas prices used in the model. • The collective minimum generation of the combination of all units that can make up this operational security requirement ranges from a minimum of 842 MW to a maximum of 1229 MW in which a portion of this and its subsequent market counterbalance must be paid for through Imperfections
2	N-1s	• The TSO's agree that Network limitations with the Must Run requirements will remain the two largest drivers of Imperfections costs in 2026/27 consistent with the RA and consultant analysis of the 2025/26 Imperfections forecast model • Over 95% of Generation constraints for Transmission restrictions would manifest themselves in the form of N-1 limitations. • This condition is more prevalent under high-RES conditions and particular in summer months when equipment ratings are operated under their lowest capability and when the system is under heavy Transmission outage conditions. • In the 2026/27 Imperfections forecast model 2298.3 GWh is considered dispatched down form RES resources largely due to N-1 conditions between the constrained and unconstrained models. This constrained energy needs to be compensated, and the associated counterbalance needs to be compensated for through Imperfections. • These criteria would have the greatest requirement for the displacement of energy from market outcomes and as such will continue to be reported as one of the top two drivers of Imperfections Costs.
3	RES/IC	• The TSO's do not fully understand the logic of this grouping by the RA's and consultants as the RES profiles used in the 2025/26 Imperfections forecast constrained model were applied as a proxy to Transmission outages while the IC profiles used in the 2025/26 Imperfections forecast constrained model were applied to represent the TSO's requirements to comply with SEM-11-062 to maximise priority dispatch on the system, System security requirements in relation to the North South Tie-Line and managing the system through low margin period avoiding alert conditions.

		• As they are applied for very differing reasons it is hard for the TSO's to decipher the relative impact of each reason being reported by the RA's and consultants. • The TSO's would contend that the majority of the impact reported is heavily weighted to the RES profiles which if combined with the N-1 scenario would further support the fact that limitations in the Transmission Network are one of the two biggest drivers of Imperfections Costs. • In the 2026/27 Imperfections forecast model 524.3 GWh is considered countertraded from Interconnector resources which is a far smaller energy imbalance that that of the RES profiles modelled which would further support the TSO's contention.
4	Reserve	• The TSO's agree with the relative placement of the Impact of Reserve requirements on Imperfections costs as reported by the RA's and Consultants. • The Imperfections impact in relation to Reserve requirements will remain the same for the 2026/27 tariff year as there has been no change in the requirements modelled from the 2025/26 forecast model that would impact the RA/consultant analysis. • A significant amount of the reserve requirements are met and modelled to be met by resources such as batteries that will not have a significant Imperfections impact. • The primary reserve requirements that have an Imperfections impact are the IE 75 MW dynamic reserve requirement, the NI 50 MW dynamic reserve requirement, the 50 MW NI negative reserve requirement and to a lesser extent the IE 325 MW replacement reserve requirement and the NI 125 MW replacement reserve requirement. • Every conventional generator will contribute to the jurisdictional dynamic reserve requirement without Imperfections impact if scheduled in the unconstrained model within a range within its operational minimum and maximum capabilities. The maximum energy displacement required for this requirement would be 1095 GWh. This displacement from market energy that needs to be compensated for through Imperfections is smaller than that of must run criteria and Transmission restriction criteria and thus will keep this significantly below the impact of these two cost

		drivers and in the mid-range of all Imperfections cost drivers • The 50 MW NI negative reserve requirement in place for the 2025/26 Imperfections forecast has not been modelled for the 2026/27 Imperfections forecast model as it is forecast to be met by renewable resources by the start of the 2026/27 Tariff year. This will reduce the Imperfections costs associated with Reserves for 2026/27, but this requirement was not included in the RA/consultant analysis so this change will not impact on the results quoted. • The IE 325 MW replacement reserve and the NI 125 MW replacement reserve requirement is satisfied by some of the most expensive OCGT units remaining offline. Given the price of these units this requirement is satisfied by market outcomes for the vast majority of trading periods and as a result has only marginal impact on Imperfections costs. This condition was not satisfied by the 2026/27 Imperfections unconstrained forecast model only ~6% of the time.
5	Inertia/SNSP	• The TSO's do not fully understand the logic of this grouping by the RA's and consultants as they are for two very different system security requirements. The TSO's do however, agree with the medium Imperfections impact reported for the two criteria combined. • All conventional units will contribute to the All-Island 23 GWs requirement if committed at any range of their output. As a result, the market can often clear this requirement without Imperfections impact and in conjunction with the 7 set must run All-Island requirement there are generally only marginal Imperfections costs over and above this for Inertia requirements. In the 2026/27 Imperfections forecast model this criterion was satisfied by the unconstrained run ~75% of the time. • The connection of Synchronous Condensers will also continue to drive down the Imperfections costs of this Inertia requirement with a new 4 GWs unit connected in January 2026 with an additional 2 GWs unit forecast to connect in October 2026 leaving the requirement to be met by non-synchronous condensers at 13 GWs. Synchronous Condensers are paid for their services outside of Imperfections and the relative displacement of market energy for them to provide this service is

		very marginal to that of the Imperfections Costs of other resources meeting this requirement. • The TSO's would contend that a large proportion of this impact is associated with the Inertia requirements. Over the last 3 years the dispatch down of renewables of SNSP reasons only accounted for on average ~ 0.8%, 0.2% and 0.2% of overall dispatch down. The dispatch down of this energy is currently not compensated for through SEM and the only impact would be the counterbalance requirement to replace this energy if demand is available to serve it.
6	IE-NI	• The TSO's agree with the positioning of the IE-NI interface constraint in the Imperfections Impact assessment reported by the RA's/consultants based on how the calculation was carried out. • A significant proportion of the cost associated with this requirement would also be included in the TSO's supplementary modelling for Interconnector countertrading requirements. If this was also factored into this analysis it might push this impact to the mid-range equivalent to Inertia and Reserves. • Much of the energy restriction on market for this requirement is seen through NI RESS and Moyle Import countertrades. In the 2026/27 Imperfections forecast model 724.8 GWh of NI RES and 114.3 GWh of Moyle imports were displaced from market position which would reflect the mid-range Imperfections impact associated with this component.
7	Generator Technical characteristics	• The TSO's agree with the positioning of Generator Technical characteristics in the RA/consultant impact assessment of Imperfections drivers. The ramp rates of most units currently on the system is relatively quick and as result the impact of this requirement on a unit's divergence from market position is short lived as a result. • With the removal of slow ramp rate coal units from the 2026/27 Imperfections forecast model will further supress this requirement from an Imperfections impact assessment.

Appendix 4: Commercial Offer Data

As a TSO, access to Participant Bidding Strategies is limited to submitted complex and simple commercial offer data (COD). PLEXOS has the capability of modelling generators in great detail, however many of the parameters used to characterise a generator in PLEXOS are commercially sensitive and not published by market participants. To account for this, calculations are carried out on participant COD data to make it compatible with PLEXOS parameters. In principle, we calculate these parameters from submitted complex COD in such a way to ensure that the overall production cost of each participant calculated by PLEXOS equates to the assumed production cost of each participant. We do not seek modelling accuracy on an individual imperfections component basis, as it would be impossible to accurately capture the hour-to-hour variability of the power system in such a way that would allow this. We validate our approach with the Backcast and apply it to the Forecast.

We develop two models in PLEXOS for each Tariff Year – an Unconstrained Model and a Constrained Model. The Unconstrained Model can be thought of as an estimation of the Day-Ahead Market, and the Constrained Model an estimation of the Balancing Market. We take the difference in cost between these two models to calculate the Dispatch Balancing Cost (DBC). While this is not an exact representation of how the electricity market works, the approach has been proven to show good correlation with how imperfections are settled. We use Supplementary Modelling to address aspects not covered by this approach or not explicitly modelled by the TSO’s PLEXOS model.

COD Parameter	PLEXOS Equivalent
Startup Cost (€)	Offtake at Start (GJ*€/GJ) + Fixed Start Cost (€)
Price Quantity Pairs (€ & MW)	Heat Rate Increments and Load Points (GJ & MW)
N/A	Gas Transportation Costs (€/GJ)
No Load Cost (€)	Heat Rate Base (GJ)
N/A	Variable Operating Maintenance (€/MWh)

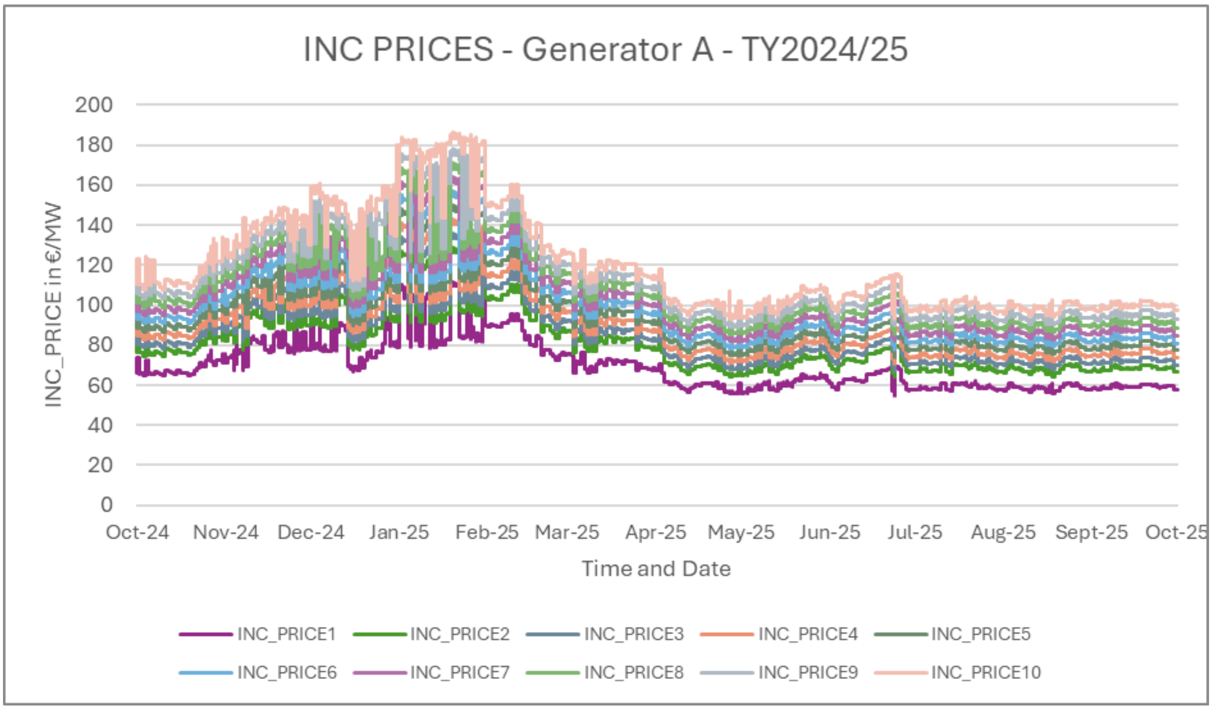
Startup Costs

This is the cost incurred for a generator to start and a DSU to shut down. If the market starts the unit, the cost is not attributed to Imperfections. However, if the TSOs need to start the generator for system reasons that haven’t been satisfied by the market, Startup Costs are paid to the unit through imperfections. Conversely, if a generator incurs less starts than the ex-ante market indicated, Recoverable Start Up Cost is charged against the unit, meaning they pay back what they earned in the EX-Ante market to start to the Imperfections pot. Generators typically have 3 startup costs, relating their heat states; cold, warm or hot. A cold generator is more expensive to start than warm, and hence this has a higher cost. We have analysed Start Up Cost data across 18 months of data, and there are minimal daily or seasonal trends associated with this, when fuel cost variation is removed.

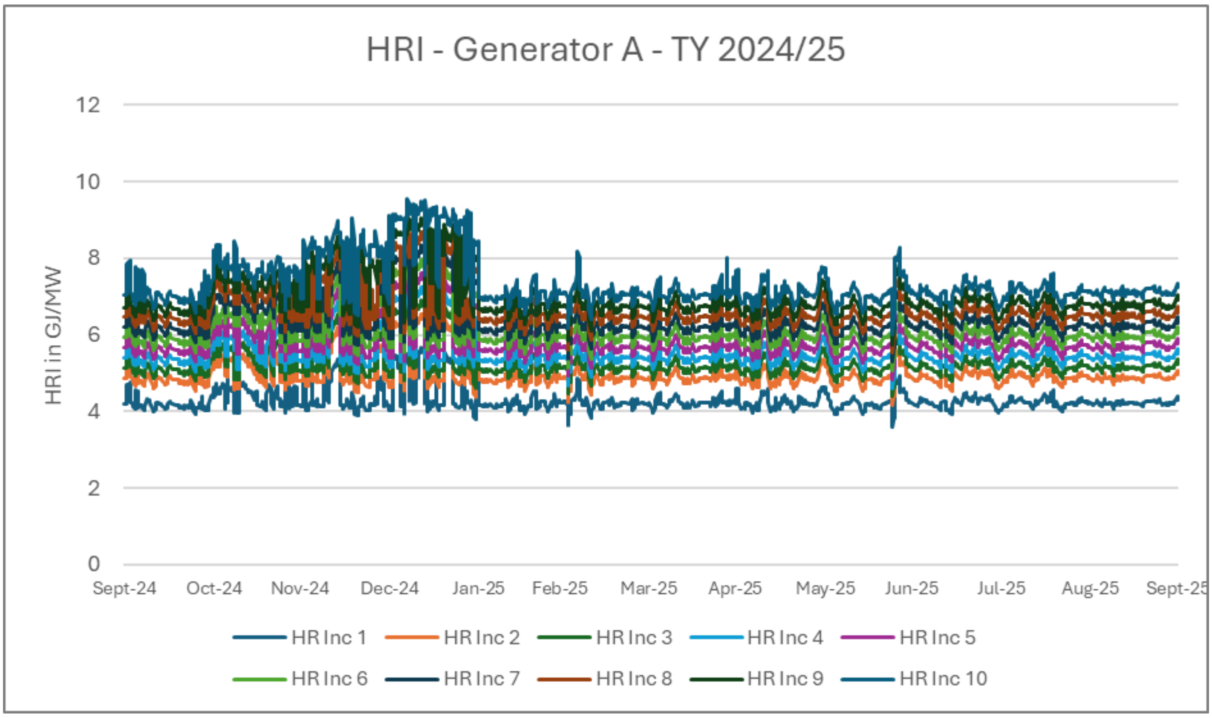
Heat Rate Increments and Load Points

The Heat Rate Increment (HRI) and load points for a unit are the PLEXOS equivalent of price quantity pairs. Rather than using €/MW values for bids, PLEXOS uses GJ/MW values, which ultimately get multiplied by the fuel cost (€/GJ) to yield euro values. Generally speaking, the HRIs for units are represented by one value per increment.

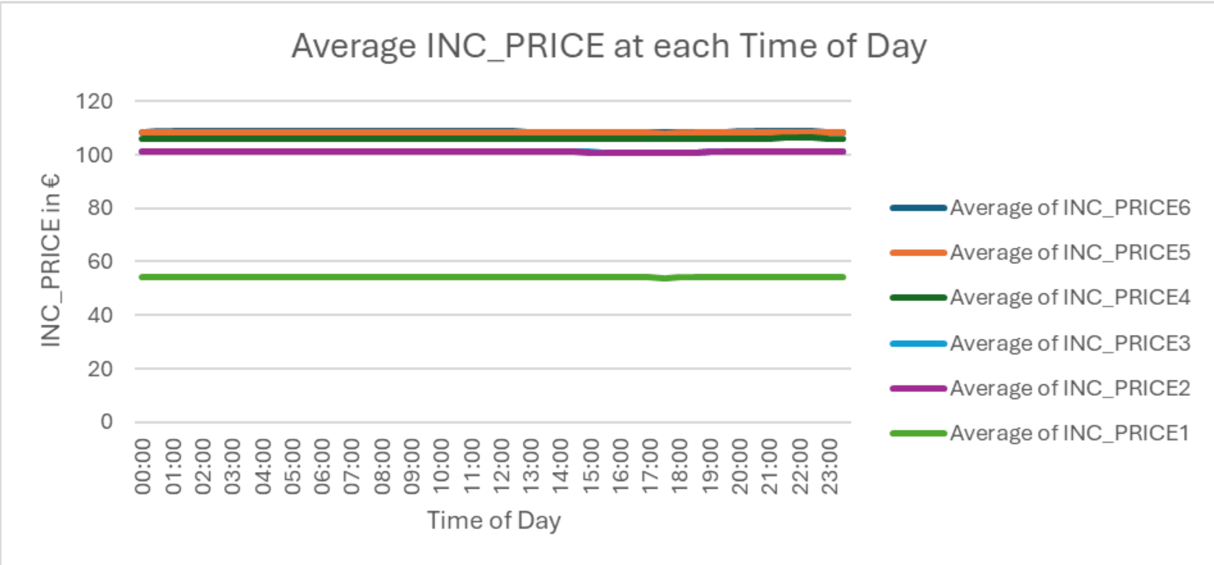
An example is given below of the Incremental Prices for a CCGT for Tariff Year 2024/25. What we would consider to be typical seasonal behaviour is seen, with submitted prices, with a steady increase from Autumn, peaking mid-winter, and then reducing as Spring progresses into Summer. Bids are then relatively flat over summer months.



The chart below shows the HRI, which, as described, is the Incremental Price normalised by fuel cost for that period. This largely removes the influence of historic fuel price on bidding. The seasonal aspect of bidding is brought into generator prices in PLEXOS via the Gas Transportation Cost parameter, which is explained in the next section.

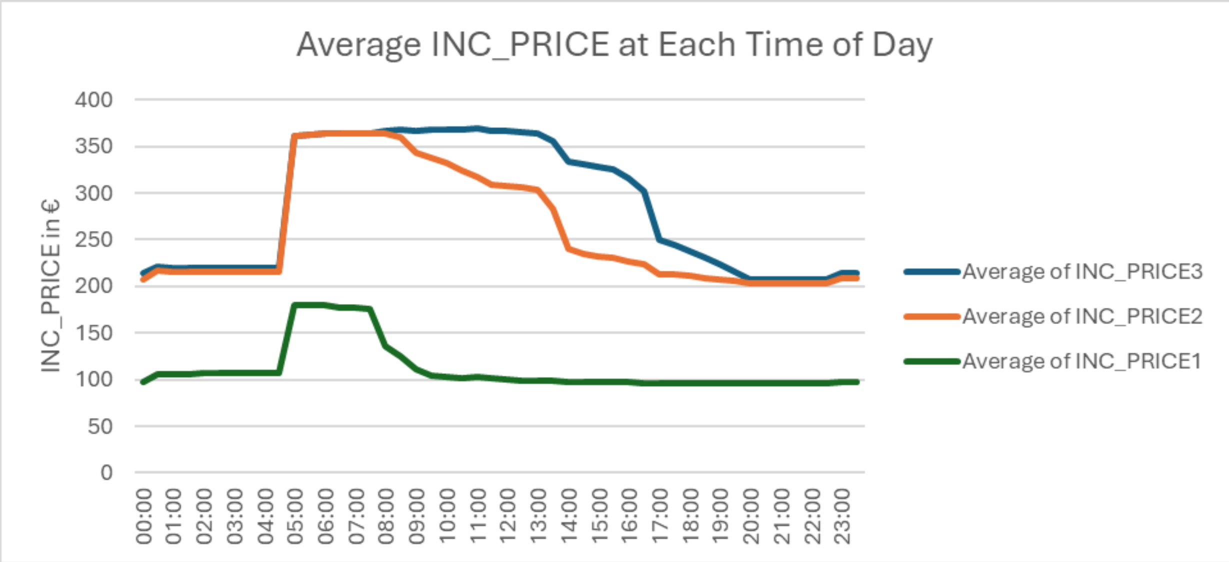


Typically, there is minimal hour-to-hour variation in the incremental prices submitted by participants. This can be seen in the chart below, which shows the average hourly bid price at all increments for a generator. The time period for this data is the full Tariff Year 24/25.



This means that bid prices can be well represented at each incremental point by single values.

However, significant in-day variation was observed for a small number of generators. A distinct daily shape can be seen in the following chart. This has been incorporated into PLEXOS by providing 24 distinct hourly prices per increment for the relevant generators.



Gas Transportation Costs

Gas Transportation Costs (GTC) is a tariff applied to the gas used by generators. This is assumed to be the main driving force behind the strong seasonal variability typically seen in participants bidding; i.e. higher bids submitted in winter months compared with summer months.

We calculate a proxy for GTC, which is used in PLEXOS to uplift generator production costs in autumn/winter/spring months. This works as a bid multiplier as follows:

$$PLEXOS\ Bid_{Month\ N} = HRI \times Fuel\ Cost \times (1 + GTC_{Month\ N})$$

The GTC values calculated out for the Generator A example is given in the below table.

Month	GTC
Mar-24	0.00
Apr-24	0.00
May-24	0.00
Jun-24	0.00
Jul-24	0.00
Aug-24	0.00
Sept-24	0.00
Oct-24	0.00
Nov-24	0.40
Dec-24	0.61
Jan-25	1.07
Feb-25	0.00

No Load Cost

No Load Cost (NLC) is a fixed cost submitted by generators to reflect their operating cost, which is invariant of output and paid for each settlement period that the generator output is greater than zero. If a unit has a PN, it will recover its NLC revenue through the Ex-Ante market. In the Balancing Market, if a unit is run without a PN, it will recover its NLC revenue through Imperfections. If the unit is synchronised with a PN of zero, it will be paid NLC for every trading period through Imperfections, and conversely, if the unit is synchronised for less settlement periods than it's PNs indicated, it will pay back recoverable NLC to Imperfections.

NLC is captured by PLEXOS via the Heat Rate Base (HRB) parameter. Generators submit NLC in euro values as part of their Complex COD. We convert this to HRB for PLEXOS by dividing by the fuel cost. HRB is paid to generators in PLEXOS whenever they are synchronised, both in the Unconstrained and Constrained model. If they are synchronised in the Unconstrained model, this means that they have a PN, and so should be paid HRB. If they then synchronised in the Constrained model, they are again paid HRB. When we calculate DBC, we subtract the Unconstrained total generation cost from the Constrained total generation cost, and so, in this example, the HRB (or NLC) cost to imperfections would be zero. In the scenario where a generator has no PN and is synchronised in the Constrained model, the full HRB (or NLC) will go towards DBC, which is reflective of how NLC is paid for through Imperfections. Finally, if a generator has a PN but is then not synchronised in the Constrained model, HRB will be paid in the Unconstrained but not in the Constrained model, so when DBC is calculated, it will act to decrease it. This reflects how recoverable NLC works in the current settlement arrangements.

Variable Operating Maintenance

Variable Operating Maintenance (VOM) is a parameter in PLEXOS designed to capture costs for generators associated with production linked operational maintenance contracts. As TSO, we are not privy to this information for generators. Our approach to this is to set the parameter to zero and attempt to capture overall production costs for generators through other COD parameters.

Appendix 5: Modelling of GB

The GB market is not explicitly modelled in our PLEXOS model. To do so accurately, it would involve a significant co-ordinated approach that would greatly add to Imperfections Forecast delivery timelines. The benefit of this exercise would be limited, as relative flows between the two markets is heavily linked to the relative availability of variable generator resources, and the conventional generator and network availability in both jurisdictions for a period of time between 7 months and 19 months in the future.

The GB market is indirectly modelled by using the three linked components of demand, RES availability and Interconnector flows sourced from actual recent market outcomes. As this approach covers a full year of data it will account of the prevalence of a delta between the relative availability of variable generation sources between the two jurisdictions. RES profiles are scaled to projected new connections, demand profiles are projected to forecasted demand growth while Interconnector profiles are assumed to remain stationary, relatively speaking. New variable generation is assumed to be absorbed by new demand, and the resultant outcome is assumed not to have a material impact on the Interconnector flows.

Appendix 6: PLEXOS Model Warning Messages

A number of warnings appear in the final PLEXOS models. Detail on these warnings is given, as well as commentary on their relevance:

No. 216 - *"Generator <name> Unit Commitment Optimality = "Rounded Relaxation" might violate [Min Up Time]/[Min Down Time] because Constraint Generators [Units Generating Coefficient] is defined."*

Triggered when PLEXOS relaxes generator minimum up time and/or minimum down time constraints in order to satisfy higher-priority system constraints.

In this model, this warning occurs where generators are dispatched in a manner that prioritises system-level constraints over minimum down time requirements. The minimum down time values should therefore be interpreted as indicative rather than strictly binding within the optimisation. This approach is consistent with real-world system operation, where operational requirements may necessitate deviations from specified minimum down times.

No. 3026 – *"Read <value> records(s) for object <name> in band <value>, but expected <value>. Default value of <value> assumed. File: <name>."*

Triggered when the input data file does not explicitly specify a value for a parameter.

In this model, it occurs where generators are not explicitly assigned forced or scheduled outage values, or where renewable units are not explicitly set to "off".

In these cases, PLEXOS assumes a default value of 0, which is consistent with the intended model setup.

No. 3043 – *"Read <value> records(s) for object <name> in band <value>, but expected <value>. File: <name>".*

Triggered when the input data file does not explicitly specify values for bands > 1.

In this model, it occurs where generators with multi-band outages are not explicitly assigned full-year values for their higher band outages.

In these cases, PLEXOS assumes that the only higher band outages are those provided, which is consistent with the intended model setup

Unserved Energy - Occurs when system demand cannot be fully met within the model due to insufficient available generation and/or network capability.

In this model, unserved energy arises during periods characterised by a combination of low renewable energy availability and elevated levels of generator forced outages. Under these conditions, available capacity is insufficient to meet demand while respecting operational and network constraints, resulting in unmet load within the optimisation.

The occurrence of unserved energy reflects stressed system conditions rather than a modelling inconsistency. This is consistent with real-world system operation, where comparable conditions would typically be addressed through additional operational measures, such as the utilisation of out of market units and/or Temporary Emergency Generation (TEG), which is not explicitly represented within this model framework.