Forecast Imperfections Revenue Requirement

For Tariff Year 2020/21

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Executive Summary

This submission represents the Transmission System Operators' (TSOs') forecast of the revenue requirement to be recovered through Imperfections Charges during the 2020/21 tariff year.

The purpose of the Imperfections Charge is to recover the total expected costs associated with managing the transmission system safely and securely, the bulk of which are under the umbrella of Dispatch Balancing Costs. Adjustments for previous years are also considered by the Regulatory Authorities in their final decision on the Imperfections Charge.

The forecast revenue requirement based on a number of assumptions and expected conditions for the 2020/21 tariff year period (01/10/2020 to 30/09/2021) is €356.67m in nominal terms. This is an increase of €54m over the equivalent forecast 2019/20 requirement of €302.65m, of which €271.3m was approved, by the Regulatory Authorities in their final decision on the Imperfection Charge.

The approach taken in the 2020/21 forecast has been to use a PLEXOS model, which assumes that the Dispatch Balancing costs in SEM, are based on the production cost difference between the unconstrained and constrained models. Additional SEM costs, not covered in the PLEXOS model, are captured in supplementary modelling.

Covid-19 has brought uncertainty to many of the underlying assumptions for the 2020/21 Forecast, including but not limited to: fuel prices, generation outages, transmission outages and forecast demand. The TSOs have extended the data freeze date to as recent as possible, to capture immediate changes that occurred, due to Covid-19.

The key factors which have influenced the total imperfections forecast cost for 2020/21 of €356.67m, in comparison to the 2019/20 forecast are:

- An increase in the scale of scheduled transmission outages has increased the PLEXOS model by €36m
- Update of Gas Transportation Capacity charges has increased the PLEXOS model by €19m
- Revised interconnector flows and wind profiles have increased model costs by €15m
- Network and Operational Constraints updates have increased the model by €15m
- Forecast demand reduction has increased the PLEXOS model constraint costs by €14m
- An increase in available priority dispatch generation contributes to an additional Imperfections cost of €8 million

- Fuel forecasts, which are lower than those of 2019/20 and have also been impacted by Covid-19, decreasing costs by €47m
- Provision of reserve by batteries has reduced costs by €20m

Supplementary Components

- Provision of €30m for New Cost Drivers in 2020/21, such as Clean Energy Package, the Must Not Run Transmission Constraint, Covid-19 and Brexit
- The costs associated with Interconnector Ramp Rates, Turlough Hill Running, MWR Removal and CABBPO/CAOOPO, which are €14.8m lower that forecast for 2019/20.

The main components of the 2020/21 forecast revenue requirement submission are set out in the table below:

Component	Forecast (€m)
PLEXOS Modelling	**265.60**
Supplementary Modelling	**74.09**
Interconnector Ramp Rate Disparity	**1.6**
Fixed Cost Payments	**15.38**
Total 2020/21 Forecast Imperfections Revenue Requirement	**356.67**

1. Introduction

This submission to the Commission for Regulation of Utilities (CRU) & the Utility Regulator for Northern Ireland (UR), collectively known as the Regulatory Authorities (RAs), has been prepared by EirGrid and SONI in their roles as the Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively.

The submission reflects the TSOs' forecast of the revenue required from the Imperfections Charge for the 12 month period from 01/10/2020 to 30/09/2021 inclusive, referred to as the tariff year 2020/21.

The primary component of the Imperfections revenue requirement is Dispatch Balancing Costs (DBC). DBC refers to the sum of Constraint Payments, Uninstructed Imbalance Payments and Testing Charges. The Constraint Payments in SEM can be broken down in CPREMIUM, CDISCOUNT, CABBPO, CAOOPO and CCURL. The cost component definitions are provided in Appendix 6. In addition to DBC, the forecast also makes provision for Fixed Cost Payments, and Other System Charges for the tariff year 2020/21. Other elements also contribute in setting the regulated Imperfections Charge including the Imperfections K factor, which adjusts for previous years as appropriate, and the forecast system demand.

The resulting Imperfections Charge is levied on suppliers, as a per MWh charge on all energy traded through the Single Electricity Market (SEM), by the Market Operator.

This forecast does not include any charges incurred for the holding, or use of, required banking standby facilities to provide working capital for the TSOs. The costs incurred as a result of holding banking standby facilities are assumed to be recoverable through the TUoS tariff and SSS tariff in Ireland and Northern Ireland under the respective regulatory arrangements pertaining.

The TSOs' forecast for the Imperfections revenue requirement is €356.67m, in nominal terms, for the tariff year 2020/21. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Context for Tariff Year 2020/21

This forecast has been prepared against the backdrop of Covid-19. The TSOs have extended the data freeze point from February to May to capture emerging changes, where possible, that have occurred due to Covid-19.

Although the TSOs have further experience with the new market, uncertainties associated with the new market still remain.

1.1.1 Background of the SEM

The wholesale electricity market arrangements for Ireland and Northern Ireland were revised under the I-SEM Project with the revised SEM arrangements going live on 1 October 2018. The new market arrangements are designed to integrate the all-island electricity market with European electricity markets, enabling the free flow of energy across borders. It consists of a number of markets including:

The Day-Ahead Market (DAM) is a single pan-European energy trading platform in the ex-ante time frame for scheduling bids and offers and interconnector flows across participating regions of Europe. The DAM involves the implicit allocation of cross-border capacity through a single centralised price coupling algorithm. The algorithm, taking into account the cross-border capacity advised by the TSOs, determines prices and physical positions for all participants in all coupled markets.

The Intra-Day Market (IDM) allows participants to adjust their physical positions closer to real time. The need to adjust their positions can arise for a number of reasons, including orders failing to clear in the DAM, new information becoming available (e.g. plant shutdowns and changes to forecasts), congestion on interconnectors driving price differentials between zones, and asset less traders wishing to exit their positions. The long-term model for a single European trading platform was based on continuous cross border trading. However, since go-live, intraday trading is only continuous within the new SEM (within-zone), where bids and offers are continuously matched on a first-come-first-served basis.

The Balancing Market (BM) determines the imbalance price for settlement of energy balancing actions and any uninstructed deviations from a participant's notified ex-ante position. The BM is different from the other markets in that it reflects actions taken by the TSO to keep the system balanced and secure, for example, any differences between the market schedule and actual system demand, variations in wind forecasting, or following a plant failure. The BM uses a rules based flag-and-tag process to determine the offers and bids that are scheduled due to system and unit constraints. It uses this information to determine the spot price in each 5 minute imbalance pricing period as the most expensively priced offer or bid that is dispatched for energy balancing rather than system constraint reasons. The imbalance price for the 30 minute imbalance settlement period is the average of the six imbalance prices.

Participants are responsible for meeting their ex-ante commitments and when they cannot they are financially exposed in the BM. Uninstructed deviations from the schedule are settled at the imbalance settlement price. Instructed deviations from balancing market actions to increase or decrease output for energy or non-energy reasons (e.g. reserves, voltage, congestion on lines, etc.) are settled at the most beneficial of either the bid/offer price or the imbalance settlement price. If the generating unit is constrained up it will be paid the higher of the imbalance settlement price or offer price, and if the generating unit is constrained down it will pay the lower of the imbalance settlement price or bid price.

1.1.2 Modelling approach for Tariff Year 2020/21

The revised SEM arrangements have seen an increase in Imperfections Costs. In the new settlement design the imbalance price is one of the major drivers of constraint costs. The imbalance price can be volatile compared to the old SEM with multiple instances of price being negative when the market is long and price being very high at times when the market is short and highly constrained. Because the production cost difference between the unconstrained and constrained model does not consider the model price, additional post processing to shadow settlement was conducted outside of the PLEXOS model. The two scenarios which cannot be captured in PLEXOS production cost difference are when the constrained up price is higher than the imbalance price and when the constrained down price is lower than the imbalance price.

Another feature of the revised SEM arrangements, that could not be fully captured in PLEXOS, is the generator offers in the new market: complex incremental/decremental costs, and simple incremental/decremental costs. Short Run Marginal Costs (SRMC) of units are represented by their unit complex incremental offers in the model, while the other three types are captured in post processing.

2. Forecast Constraint Costs

This section sets out the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2020/21, including the results of the forecast costs from the PLEXOS model, in addition to the supplementary modelling, as outlined in Sections 2.1 and 2.2 respectively. A summary of other components of the Imperfections revenue requirement is outlined in Section 2.3.

2.1 PLEXOS Results

The forecast cost of the constraints modelled using the PLEXOS model for the 2020/21 tariff year is **€265.60m**. For reference the PLEXOS cost for 2019/20 was €234.57m.
The most significant influences on forecast constraint costs, compared to that forecast in 2019/20, in the PLEXOS model are:

- An increase in the scale of scheduled transmission outages has increased the PLEXOS model by €36m
- Update of Gas Transportation Capacity charges has increased the PLEXOS model by €19m
- Revised interconnector flows and wind profiles have increased model costs by €15m
- Network and Operational Constraint updates have increased the model by €15m
- Forecast demand reduction has increased the PLEXOS model constraint costs by €14m
- An increase in available priority dispatch generation contributes to an additional Imperfections cost of €8 million
- Generator and Interconnector Outages, which contributes to €4m increase
- Revised technical characteristics of generators incorporated in model, which has reduced costs by €6m
- Updated DS3 milestones (SNSP and inertia level) has reduced costs by €6m
- Provision of reserve by batteries has reduced costs by €20m
- Fuel forecasts, which are lower than those of 2019/20 and have also been impacted by Covid-19, decreasing costs by €47m

There are a number of factors which may influence the forecast costs, and hence the Imperfections revenue requirement, for the tariff year 2020/21. Influencing factors are described in the following sections.

2.1.1 Generation Merit Order

Compared to the tariff year 2019/20 forecast, there has been a change in the generation mix available in the market. There is an increase in priority dispatch generation from wind and solar. This has the effect of increasing DBC as the unconstrained model uses this as much as possible, pushing more expensive conventional generation out of the merit order. The constrained model still needs to run specific generators that may have become out of merit due to the increase in priority dispatch generation.

2.1.2 Fuel Prices/ GTCs

There is a decrease in forecast wholesale fuel prices and carbon for 2020/21, Figure 1 outlines the differences in the fuel prices from the 2019/20 forecast to the 2020/21 forecast; this makes the cost of constraining on out of merit generation less expensive and drives a lower production cost in the constrained model. The result is that the disparity between the unconstrained and constrained model production costs decrease, and with it the DBC.

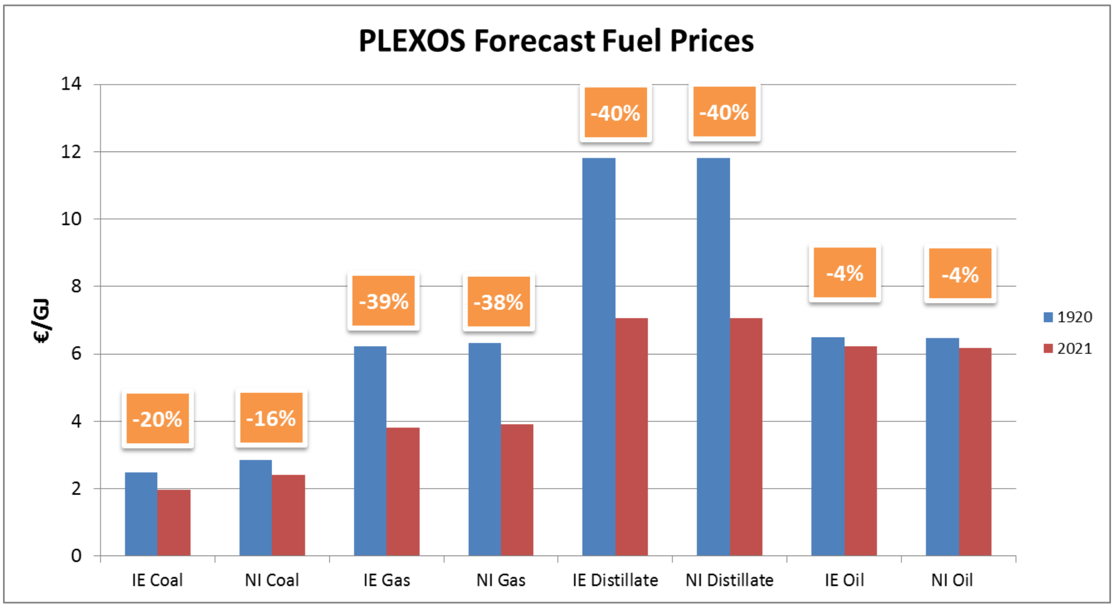

Figure 1: Forecast Model Fuel Cost Changes from 2019/20 to 2020/21

It has been assumed that ten gas-fired generation units in Ireland and three gas fired generators in Northern Ireland will now include the cost of particular gas network capacity products in their generator offers, based on current Gas Transportation Capacity (GTC) charges. This increases the offer price of these units and leads to increased constraints costs, when they are constrained on in dispatch, to meet reserve, transmission or security constraints, on the power system. In general, the GTCs assumed for each unit have been based on analysis of historic generator bids.

2.1.3 Interconnection

Forecast interconnector flows for 2020/21 are based on historic actual interconnector flows, matched with historic actual wind availabilities. As interconnector and wind profiles are so closely linked, the approach of using these two 'already matched' sets will assist in modelling reality. Moyle exports were limited to 83MW for all of the 2020/21 tariff year.

2.1.4 Transmission Outages

There is a significant programme of outages scheduled to take place on the transmission system during the 2020/21 tariff year, which in turn results, in an increase in DBC. Amongst the most prominent of these outages is the refurbishment of critical elements of the 220kV and 400kV network, contributing to an increase in Imperfection Charges. All outages by their nature reduce the flexibility of the system, due to unavailability of transmission plant; however refurbishment of the 220 kV and 400 kV network can be especially onerous, due to the impact on bulk power flows. Another factor is the duration of refurbishment outages, with work required along the entire length of a circuit, thus increasing the duration of the outage. As a result, the outage forecast for the 2020/21 Imperfections model is more onerous and of a longer duration, than forecasts in previous years. The outage requirements for the 2020/21 are based on the best available information, as of June 2020, including consideration of the impact of Covid-19. The TSOs have carried out a desktop exercise of the indicative transmission outages, scheduled to take place during the 2020/21 tariff year and have included the relevant outages from a DBC perspective in PLEXOS. These outages are listed in Appendix 3 of this submission paper.

2.1.5 Network and Operational Constraint Updates

The transmission network has been update to reflect the forecast configuration. The monitoring of additional N-1 contingency scenarios has been included. N-1 contingency is there to ensure the network can withstand the loss of any single item of power in feed or transmission equipment at any time. Also, station sectionalising has been updated to reflect the most common mode of operation. The best estimate of operational policies/ TCGs that will be in effect for the tariff year has been considered in the model.

2.1.6 Impact of Storage on Reserve

In order to ensure the continued security and stability of the transmission system in the event of a generator tripping, the TSOs instruct some generators to run at lower levels of output, so that there is spare generation capacity available (known as reserve), which can quickly respond during tripping events. This is one reason why the actual dispatch may deviate from market schedule, which contributes to DBC costs. The inclusion of storage/ batteries in the 2020/21 Forecast helps reduce this cost, as it is assumed that these units will be available to provide reserve and therefore they replace the reserve previously obtained from thermal units.

2.1.7 System Operator Countertrading

For the 2020/21 forecast, countertrading has been disabled in the constrained model for EWIC and Moyle. This assumption is based on the experience of the last 12 months, when only a limited number of Cross-Zonal trades have been executed.
The TSOs are currently only countertrading for maximising priority dispatch and for system security reasons in exceptional circumstances, the need for which has been minimal since Go-Live of the revised SEM arrangements.

2.2 Supplementary Modelling Results

The individual components of supplementary modelling, which take account of specific external factors that cannot be captured in PLEXOS modelling, are outlined and discussed in Appendix 1.

The forecast cost of the constraints modelled by the supplementary modelling for the tariff year 2020/21 is **€74.09m**. This represents an increase of €23.6 from the 2019/20 tariff year.

The largest influences on the changes to supplementary modelling are:

New Cost Drivers in 2020/21: A provision of €30m against additional costs drivers in 2020/21 has been sought. This forecast cost represents a conservative estimate by the TSOs of the potential cost impacts on Imperfections as a result of:

- Must Not Runs:
  As of 25 May 2020, a “must-not-run” TCG came into effect, which manages the equivalent operating hours for particular generators to minimise risks for margins across Winter 2020/21. This TCG currently applies to B31, B32, HN2 and DB1. It is likely that this constraint will endure for circa. 10 weeks of the 2020/21 Forecast year at a forecast cost of c. €15m.

- Clean Energy Package:
  Article 12 and Article 13 of Regulation EU 2019/943, which forms part of the Clean Energy Package, potentially have implications for priority dispatch and compensation for curtailment in SEM, and therefore for imperfections costs, during the 2020/21 tariff year. The RAs issued a consultation paper on 27th April 2020, on the implementation of this Regulation. In this consultation paper the RAs have sought comments on seven potential options for implementation of the Regulation, and have estimated a cost of up to €140m to imperfections, depending on which option is implemented.

- Covid-19
  The full impact of the Covid-19 pandemic on demand forecasts and the wider economy is unclear at this time. If there was to be a second wave of the Covid-19 pandemic during winter 2020/21, this would be likely to have an even greater impact as that is a higher demand time of year. Hence the TSOs are of the opinion that it is reasonable to seek some level of contingency imperfections cost against this not unlikely scenario.

- Brexit
  Another factor that could impact on generator bidding behaviour and market interconnector flows is the impact of Brexit. This includes fluctuations in the Euro/Sterling exchange rate and any changes in GB energy policy.

The combination of these particular risks differs from standard risks which are present in any forecast (with such standard risks being addressed through the standby capital facility). The fact that these risks are not systemic in nature and will on incurrence give rise to higher costs and the increased likelihood of their incurrence, in some cases close to certainty, means that a provision needs to be placed *ex ante* in the allowance for 2020/21.

While on balance it could be argued that the provision should be higher the TSOs believe that this level of provision (€30m) included *ex ante* is a prudent and necessary approach and allows for potential further increased costs to be managed via other adjustment mechanisms (changes to standby debt or review of the charge factor) noting that such other adjustment mechanisms can have a time lag for implementation.

Additional CPREMIUM and CDISCOUNT Payments and Imbalance Price Impact: The imbalance price under the revise 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 costs are not covered under the BMPCOP. The reason this is important to DBC, is that the TSOs have to pay a generator the better of their offer price and imbalance price, for non-energy actions taken. This extra cost is not taken into account using the production cost based PLEXOS modelling. Therefore an additional provision of €24.25m has been calculated within supplementary modelling for the entire 2020/21 tariff year. This calculation is based on actual imbalance prices from the last 12 months.

This impact was calculated by applying the settlement calculation for the two highest settlement cost components CPREMIUMS and CDISCOUNTS. The calculation was done by multiplying the dispatch volume difference between the two models by the generator offer price, if the offer price was better than the imbalance price. To account for the simple price offers, the premiums and discounts were calculated again. The percentage that the offer was settled on, simple vs. complex, was applied across the calculations to avoid double counting.

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. During the day, the units are often kept at their Minimum Generation levels to provide positive 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 CPREMIUMS and CDISCOUNTS paid by the TSOs to pump storage units. Another considerable difference is the offer prices associated with pump storage units in the old market compared to the new market. Pump storage units in the old market were bidding in with a price of 0 €/MWh and were not paid for non-energy actions, whilst in the new market their bid offers are considerably higher. PLEXOS cannot capture the pump storage unit offer prices, thus the provision is included in the supplementary modelling. The provision is based on the actual CPREMIUM and CDISCOUNT payments the pump storage units received in the last 12 months.

CABBPO/CAOOPO ‘Undo’ Actions: CABBPO and CAOOPO are two new settlement cost components, under the revised SEM arrangements, for the ‘Undo’ actions, the main intent of which is to ensure units gain some compensation, for energy bought under the instruction of the TSOs, if subsequently the TSOs decided against taking, or “unwinding” a bid offer acceptance. The logic behind this is that there may have been some incurred costs, which need to be recovered, e.g. if a unit was asked to SYNC with long notice, they could use that time to procure gas from the gas market, then if they are subsequently told not to SYNC, they have incurred the cost of the gas they bought, but have no way to recover that cost. The costs of these 'Undo’ actions have decreased over the last year, to minimal levels, and on that basis the TSOs will be requesting €0m.

MWR[1] **Removal:** Following the event on 24 January 2019 when the Imbalance price reached 3773.69 €/MWh, a modification (Mod_09_19[2]) was approved by the SEM Committee to remove the MWR locational constraints to prevent future similar events. As part of the discussion of this modification at the Trading and Settlement Code Modifications panel, it was acknowledged that the removal of this constraint could lead to instances where generators are settled on their simple offer data rather than their complex offer data as they would no longer be flagged out. While the MWR Removal, means more instances of units being settled on simple offer data rather than complex, it also contributes to a lower Imbalance Price. Due to the complexity of determining the interaction between these two factors, the TSOs are not making a request for this component this year.

Constrained Wind: Wind is currently not paid for curtailment in SEM, however it is paid for constraints. Because the wind in the PLEXOS model has a price of 0 €/MWh, the provision of €3.53m is included within supplementary modelling. This figure is based on the actual CDISCOUNTS wind participants received in the last 12 months up to 30/May/2020.

Interconnector Ramp Rate Disparity: Under the revised SEM arrangements an imbalance volume and cost arise between differences in interconnector ramp rates in Euphemia (day ahead pricing algorithm currently in use throughout Europe) and real time operations. In general the higher the ramp rate in Euphemia the higher the imbalance volume and cost. For the 2019/20 Imperfections Forecast the TSOs recommended an allowance of €3.2m for this, based on the part-year data available at that time. For the 2020/21 Imperfections Forecast there is a full year of empirical data available and this was used to calculate a required provision of €1.6m.

Long Notice Adjustment Factors: As per SEM-19-065, the Long Notice Adjustment Factor (LNAF) has been set zero until 31/12/2020. A consultation is due to be carried out in August 2020 to determine the values from January 2021 onwards. A provision of zero was therefore made for the 2020/21 forecast.

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[1] MWR: is a type of Transmission Constraint Group (TCG) related to N-S flows

[2] The details of Mod_09_19 can be found at www.sem-o.com/rules-and-modifications/balancing-market-modifications/market-rules/

2.2.2 Changes for 2020/21

The results of all elements of the modelling process in 2020/21 are summarised in the table below:

Description	2020/21 Forecast (€m)
PLEXOS Modeled Constraints for 12 Months	265.60
Additional CPREMIUM and CDISCOUNT Impact	24.25
Dispatch of Pump Storage Units	11.60
CABBPO/CAOOPO ('Undo' Actions)	0.00
MWR removal	0.00
Block Loading	0.08
Capacity Testing & Performance Monitoring	4.23
Secondary Fuel Testing	0.4
Constrained Wind	3.53
New Cost Drivers in 2020/21	30.00
Supplementary Modeling Total	74.09
Total Constraint Costs	339.69

2.3 Imperfections Charges – other components

In addition to the €339.69m forecast of constraint costs above, the TSOs are setting out the following additional forecast costs for inclusion in the total revenue requirement. A further description of the individual Imperfections elements is given in Appendix 1 of this document.

Component	Forecast (€m)
Dispatch Balancing Costs	**339.69**
- Constraints	**339.69**
- Uninstructed Imbalances [3]	**0.0**
- Testing Charges [4]	**0.0**
Fixed Cost Payments [5]	**15.38**
Interconnector Ramp Rate Disparity	**1.6**
Other System Charges	**0.0**
FORECAST IMPERFECTIONS REVENUE REQUIREMENT	**€356.67**

[3] *It is assumed that the constraint costs of **Uninstructed Imbalances** (for over and under generation) will, on average, be recovered by the Uninstructed Imbalance Payments for the forecast period. In the event that uninstructed output deviations occur within the tariff year, corresponding constraint costs will also arise.*

[4] *A zero provision has been made for the net contribution of **Testing Charges**, as any testing generator unit will pay Testing Charges to offset the additional constraint costs that will arise from out of merit running of other generators on the system as a result of the testing.*

[5] *The purpose of **Fixed Cost Payments** is to account for specific additional costs incurred or saved in respect of a Unit where, as a result of a Dispatch Instruction, the Unit is dispatched differently to its Final Physical Notification. They are funded by Imperfections. A provision for the Fixed Cost Payments for the 2020/21 tariff year is included in this submission.*

3. Risk Factors

A large number of risk factors should be considered when assessing the Imperfections Revenue requirement for 2020/21. The factors are set out below, with brief descriptions of the nature of these risks and potential mitigation measures. These factors could individually or collectively result in a significant deviation between the forecast and actual constraint costs. These factors are in addition to the factors outlined in “New Cost Drivers in 2020/21” in Section 2.2.

3.1 Specific Risks

3.1.1 Poor Generator Availability and/or Generation Station Closure

A reduction in the overall availability of generation could lead to an increase in DBC as relatively more expensive generation may be required to provide reserve and/or system support in areas with transmission constraints. Significant deviation from indicative generator scheduled outages and return to service dates could also lead to large variances in DBC.

3.1.2 SEM Design/ Modifications to the SEM Trading and Settlement Code

All assumptions made in this submission were based on the current version of the Market Rules. The impact of future rule changes has not been considered and must be deemed a potential risk.

This submission has attempted to capture the main potential impacts of the imbalance price and different offer types to DBC; however it is likely that other unknown risks at the time of data freeze have not been accounted for and would only become clear following their implementation in the new market.

3.1.3 Delays and Overruns of Outages

Outages by their nature reduce the flexibility of the system due to unavailability of generation and/or transmission plant. Delays in the scheduled start dates, overrun of any outages and unexpected outages will extend this state of reduced flexibility and may result in an increase in DBC.

3.1.4 Network Reinforcements and Additions

The PLEXOS model was built with the most up to date data available at the time of the data freeze. The commissioning dates of projects in the future may change and any delays or advancements of dates will have an impact on how the system can be run. Examples of this include delays to network reinforcements, delays to new generator commissioning, unexpected or early generator closures or long-term forced outages. The actual detailed planning of outages is only carried out in the weeks preceding outages as factors such as other transmission outages, generation outages, resourcing, etc. can be fully realised at this stage.

3.1.5 Interconnector Flows and System Operator Countertrading

Market interconnector flows have been forecast using historical data from SEM. Participant behaviour could result in interconnector flows that differ greatly from those forecasts. This, in turn, could result in constraint costs changing significantly.

3.1.6 Significant Bid Variations

The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long term fuel prices at the time of May 2020, our data freeze. There is typically considerable volatility in fuel prices in both short and long term timeframes. A general increase in fuel prices would lead to higher generator running costs and hence higher Dispatch Balancing Costs. Other factors such as changes in the cost of carbon, generator Variable Operation and Maintenance (VOM) costs or gas network capacity products could also have a significant impact.

A number of generators include a gas product charge in their offers to the SEM, which has increased DBC. These generators have been taken into account in this forecast. However if any additional gas generators include a gas product charge in their offers this will increase DBC.

3.1.7 High Impact, Low Probability Events (HILPs)

In respect of this forecast, 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 (e.g. due to a fault on an underground cable which could have a long lead times to repair) may result in generation being constrained until the repair can be completed.

PLEXOS does include planned generator outages in the model but these tend to be co-ordinated with transmission outages and they are timed to minimise their impact on constraints. Forced outages for generating units are also modelled to account for some unplanned events. PLEXOS will therefore account for some constraint costs associated with outages but not major HILP events affecting generation and/or transmission plant(s). In such an event involving transmission equipment, the TSOs would obviously seek to implement mitigation measures where possible.

3.1.8 Outturn Availability

A change in practice in relation to the treatment of outturn availability of generators during transmission outages[6] could have an impact on constraint costs.

[6] http://www.eirgridgroup.com/site-files/library/EirGrid/The-EirGrid-and-SONI-Implementation-Approach-to-the-SEM-Committee-Decision-Paper-SEM-15-071-Published-10-February-2016.pdf

3.1.9 Forced Outages of Transmission Plant

The forced outage of transmission plant may lead to increased DBC due to resultant generator and/or transmission constraints. The outage of certain key items of the transmission system can potentially increase DBC significantly. For example, if a generator is radially connected to the system and the radial connection is forced out, the impact on DBC can be considerable. In addition, the possibility of equipment failing due to a type fault affecting a particular type or model of equipment installed at numerous points on the transmission system, for example, could have a major impact on constraint costs. Forced transmission outages are not modelled in PLEXOS and no explicit provision has been included due to the unpredictable nature of such outages.

3.1.10 Market Anomalies

Unknown or unintended results from the market scheduling software could lead to unexpected market schedules which form the baseline from which constraints are paid. It is expected that any major anomaly would be quickly identified and corrected to prevent major constraint costs arising.

3.1.11 Participant Behaviour

The PLEXOS modelling process has assumed that participants offer into the market according to their fuel costs and technical availability. There has been no extra provision made for any possible bidding strategy by a market participant as it is assumed the Balancing Market Principles Code of Practice (BMPCOP) is followed for their complex commercial offer data. Therefore the role of the market monitor in monitoring the behaviour of participants and acting in a timely manner is important. Under the revised SEM arrangements, simple bids and offers of generators are not bound by the same guidelines of the BMPCOP. These simple offers and bids set the imbalance price and therefore impact DBC, due to the fact that the TSOs are paying the better of the generator offer and Imbalance price for a non-energy action.

3.1.12 Testing Charges

There is no specific DBC provision for new units that will be under test before they are commissioned, or on return from a significant outage. It is assumed that the testing charges will offset the additional DBC incurred, which will primarily consist of constraints, due to out of merit running (e.g. for the provision of extra reserve). However, the testing charges do not cover any transmission-related constraints that arise due to new unit commissioning (as these are difficult to predict in advance).

3.1.13 Contingencies

A list of the principal N-1 contingencies was included in the PLEXOS model. It was assumed that other contingencies had a negligible effect or could be solved post contingency. However, if a significant contingency outside of this list was to occur, and persisted for an extended period, then this could have a significant impact on constraint costs.

3.1.14 Additional Security Constraints

This forecast has been prepared 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, and additional security constraints may be required, resulting in a change in constraint costs.

3.1.15 SO Interconnector Trades for System Security

SO Interconnector trades may be required to maintain system security in exceptional circumstances, for instance during a capacity shortfall, where generation is insufficient to meet demand.

3.1.16 Industrial Emissions Directive

In Ireland and Northern Ireland, some units are affected by the Industrial Emissions Directive (Directive 2010/75/EU of the European Parliament and the Council on industrial emissions). These units may need to purchase additional permits for emissions. A provision for costs arising from this has not been included in the 2020/21 forecast.

3.2 Other Risk Factors

While a number of key specific risks have been explicitly identified and outlined in Section 3.1 above, there are other factors that may contribute to unexpected increases/decreases in DBC including exchange rate variations, operation of generators on distillate when they are assumed to run on gas in the PLEXOS model, the impacts of two-shifting generation on the reliability of the plant, significant variations in system demand and operation with significant penetration of variable generation.

4. Imperfections Charge Factor

Under the current SEM arrangements, as per the Trading and Settlement Code Part B, RA approval is required for the Imperfections Charge Factor (**FCIMPy**).

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 of anticipated costs, to seek approval from the RAs to increase the factor, thus increasing 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.

It should be noted that under Section F12.1.4 it is only possible for the Imperfections Charge Factor to be adjusted to effectively increase the rate at which monies are being recovered within a year; there is no clause that provides for the Factor to be set to reduce the rate of recovery.

As such, and in accordance with Section F.12.1.1 (b), EirGrid and SONI are now seeking the approval for the Imperfections Charge Factor to be set to 1 for the period of 1 October 2020 to 30 September 2021.

5. Total Revenue & Regulatory Cost Recovery

Given the extent of total DBC, and in the context of increased unpredictability and volatility seen under the new market arrangements, the principle of costs being 100% pass-through through the k factor as per the current arrangements, is of paramount importance. Should there be an overall imbalance, or an expected imbalance for the tariff period as a whole, either to the account of customers or to the licensees, then a best estimate will be provided for through the k factor.

Under Section F.22 of Part B of the Trading and Settlement Code, which addresses actions to be taken in the event of working capital shortfalls, the business will cease making payments out in the event that the standby debt facilities' limits are hit. In this context it is of absolute importance that the Imperfections Charge is set against the full forecast provided in this paper, along with the full k factor which is being submitted separately.

Appendix 1: Overview of Imperfections and Modelling Constraint Costs

1. Overview of Imperfections

The purpose of the Imperfections Charge under the revised SEM arrangements remains similar to that in the old market i.e. to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Fixed Cost Payments, over the Year, with adjustments for previous years as appropriate. As noted in Section 1, adjustments for previous years are not included in this submission, but are considered in setting the Imperfections Charge.

The three components of Dispatch Balancing Costs, namely Constraints, Uninstructed Imbalances and Testing Charges are described in further detail in Sections 2, 3 and 4 of this Appendix respectively. Other System Charges are detailed further in Section 5. Section 6 describes Energy Imbalances and their interaction with DBC, while Section 7 discusses Fixed Cost Payments.

2. Constraint Costs

2.1 Overview of Constraint Costs

Constraint costs are the largest portion of the DBC. The TSOs, in ensuring continuity of supply and the security of the system in real time, have to dispatch some generators differently from the output levels indicated by the ex-post market unconstrained schedule. 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') and the actual instructions issued to generators (the 'actual 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'.

In order to balance supply and demand, a generator that is constrained off/down will always result in other generators being constrained on/up and vice versa. The units that are constrained off/down have to pay back a constraint payment (negative) and the corresponding units that are constrained on/up receive a constraint payment (positive). As the price of the constrained on/up unit is generally greater than the constrained off/down unit, there is always a net cost associated with constraints.

The actual dispatch of generation is based on the same commercial data as used in the production of the market schedule. However, the TSOs must take into account the technical realities of operating the power system. As such, dispatch will deviate from the market schedule to ensure security of supply. Constraint costs arise whenever dispatch and market schedule diverge.

Section 2 below describes the main categories of issues that can lead to a difference between the market schedule and actual dispatch and hence constraint costs.

2.2 Why do Constraint Costs Arise?

2.2.1 Transmission

In order to ensure the safe and secure operation of the transmission network, it may be necessary to dispatch specific generators to certain levels to prevent equipment overloading, voltages going outside limits or system instability. 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.

2.2.2 Reserve

In order to ensure the continued security and stability of the transmission system in the event of a generator tripping, the TSOs instruct some generators to run at lower levels of output so that there is spare generation capacity available (known as reserve) which can quickly respond during tripping events. To maintain the demand-supply balance, some generators will be constrained 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.

2.2.3 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 that generators can synchronise and reach their minimum load level in 15 minutes, whereas in reality this may take much longer; 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.

2.3 Managing Constraint Costs

Constraint costs will inevitably arise due to the factors described above and they are also dependent on a number of underlying conditions. Some of these conditions, such as fuel costs, generator forced outages, trips, start times, overruns of transmission outages, 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. The TSOs undertake a number of measures to control and mitigate the costs of re-dispatching the system.

These measures include, but are not limited to:

- Performance Monitoring, which identifies levels of reserve provision and Grid Code compliance. The TSOs also analyse the performance of each unit following a system event and follow up with those units that do not meet requirements or do not respond according to contracted parameters.

- Applying Other System Charges (OSC) on generators whose failure to provide necessary services to the system lead to higher DBC. OSC include charges for generator units that trip, for those which make downward declarations of availability at short notice and Generator Performance Incentives (GPIs). GPIs monitor the performance of generator units against the Grid Code and help quantify and track generator performance, identity non-compliance with standards and assist in evaluating any performance gaps. OSC are discussed further in Section 5 of this Appendix.
- Wind, Solar and Load forecasting, which involves continually working with vendors to improve forecast accuracy.
- Introducing additional Ancillary Services which will provide a system benefit, through the new DS3 System Services[7].

2.4 Modelling Constraint Costs

2.4.1 Approach to Constraints Forecasting

Detailed market, transmission system and generation models were developed and analysed utilising the simulation package PLEXOS, which captures the key transmission and reserve constraints. Supplementary modelling was then used to examine factors affecting constraints that could not be accurately modelled in PLEXOS.

As this is an estimate of constraints approximately a year ahead, the assumptions that are made are critical to the forecast. Where possible, data from the new SEM, such as Commercial and Technical Offer data, historical dispatch quantities, market schedule quantities and constraint payments, has been used to review key assumptions.

In the following sections, details of the key assumptions, the PLEXOS model and the analysis of specific effects on DBC are presented.

2.4.2 Key Modelling Assumptions

The TSOs have made a number of assumptions in preparing this submission. The principal ones are:

- Where reference is made to the Trading and Settlement Code (T&SC), the version referred to is Part B dated 19 April 2019.
- For the purpose of this submission all expenditure and tariffs are presented in euro. The euro foreign exchange rates from the European Central Bank are used for any money originally in pounds sterling and US dollars.

The following table highlights the key assumptions used in the production of the constraints in PLEXOS for the TSOs' Imperfections revenue requirements forecast. A further summary of the PLEXOS modelling and associated assumptions is provided in Appendix 2.

[7] http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/#comp_000056cb5b8e_00000006da_78f0

Subject	Assumption
Data Freeze	All input data for the PLEXOS model was frozen at 27/05/2020.
Forecast Period	The forecast period is from 01/10/2020 to 30/09/2021.
Currency	All costs are modelled in euro.
Fuel and Carbon Prices	Fuel prices for 2020/21 are based on the long term fuel forecasts from Thomson-Reuters Eikon[8], the US Energy Information Administration[9] and data gathered by the TSOs. Carbon costs and Variable Operation and Maintenance Costs are also forecast.
Participant Behaviour	It is assumed that generators bid according to their short run marginal costs in SEM in line with the current Bidding Code of Practice[10].
Demand Forecast	The demand is based on the 2020/21 forecast for both Northern Ireland and Ireland as of May 2020. This demand forecast considers the impact of Covid-19.
Generator Schedule Outages	2020 and 2021 maintenance outages are based on provisional outage schedules. Return Dates for the units are based on the latest available information from the Generator units as of the data freeze.
Generator Forced Outage Probabilities	Forced Outage Rates and Mean Times to Repair are based on historical data held by the TSOs.
N-1 Contingency Analysis	Principal N-1 contingencies, based on TSO operational experience, are modelled.
Transmission Scheduled and Forced Outages	A number of significant indicative scheduled transmission outages for 2020/21 are modelled in PLEXOS. Forced transmission outages are not modelled.
Operating Reserve	Primary, secondary and tertiary 1 and 2 reserve requirements are modelled[11]. The output from open cycle gas turbines and peaking plant generation units is limited in the constrained model to ensure that adequate replacement reserve is maintained at all times.
Louth-Tandragee Tie-Line Transmission Limits	The Net Transfer Capacity (NTC) is modelled for the constrained schedule, which is assumed to be 250 MW N-S and 300 MW S-N.

[8] https://thomsonreuterseikon.com/
[9] https://www.eia.gov/
[10] The Bidding Code of Practice - AIP-SEM-07-430
[11] http://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Constraints-Update-Version-2019.pdf

Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast based on actual flows derived from the new market.
Intra-Day Trading	No explicit modelling provision has been made to reflect Intra-Day trading in the PLEXOS model.

2.4.3 PLEXOS Modelling

PLEXOS for Power Systems is a modelling tool which can be used to simulate the SEM. It can be used to forecast constraints over an annual time horizon using the best available data and assumptions. However, like all models, it will never fully reflect operational reality and cannot be used to derive an estimate for any one specific day. As the model was set up for a 12 month study horizon it is important that all results are considered according to this timeframe, rather than being considered for specific months and/or periods of the tariff year in isolation.

This analysis used a model of the transmission and generation systems across the whole island, with assumptions around factors such as outage schedules, demand levels, plant availability, fuel prices and wind output. The model also took account of reserve requirements and specific transmission constraints, so that the effect in terms of total production costs could be analysed.

It assumed that, in line with the Bidding Code of Practice, the generators bid their short run marginal cost into the market and this was the basis for setting the system marginal price and determining constraint costs. The difference in production costs between the unconstrained (market) simulation and the constrained (dispatch) simulation represents the constraint costs associated with the modelled transmission and reserve constraints.

2.5 Supplementary Modelling

As it is not possible to model all constraint cost drivers in PLEXOS, further analysis of specific factors affecting constraints was performed. This built on the PLEXOS modelling described above and looked at the impact of:

- Market modelling assumptions
- System security constraints
- New design items under new arrangements which could not be modelled

These are discussed, in detail, in the following sections.

2.5.1. Market Modelling Assumptions - Block Loading

The UUC market schedule assumes that, when synchronising, a generator can reach minimum load in 15 minutes. In practice, it can take significantly longer, particularly for cold units. In actual dispatch therefore, it will be necessary to synchronise such units earlier than the UUC market schedule, resulting in out-of-merit running and hence constraint costs. A provision is included to cater for the constraints costs arising from out-of-merit running due to the simplification of block loading in the market model.

Although a number of other market modelling assumptions such as the single ramp rate and forbidden zones diverge from reality, it is assumed that the constraint costs arising from these assumptions will balance out over the course of the tariff year.

2.5.2. System Security

2.5.2.1. Capacity Testing for System Security & Performance Monitoring

In the interests of maintaining system security, it is considered prudent operational practice to verify the declared availability of generators in accordance with the monitoring and testing provisions of the Grid Codes. This ensures that the TSOs are using the most accurate information possible and allows generators to identify any problems in a timely manner.

With increasing amounts of base-load thermal and wind generation, there will be more instances of out-of-merit generators not being required to run. Testing the capacity of such units from time to time will necessitate constraining them on, resulting in an increase in constraint costs. A provision is included in this submission, calculated based on an estimate of the additional start costs and out-of-merit running costs, but taking into account additional starts assumed under the Long Start-Up and Notice Times provision.

Testing of generators for Grid Code compliance and performance monitoring is also necessary for system security. To date, no significant additional costs have been incurred due to this testing and so no explicit provision for this is included here.

2.5.2.2. Secondary Fuel Start Up Testing

A provision has been made to constrain on Open Cycle Gas Turbines (OCGTs) during their tests and to constrain on the marginal unit during Combined Cycle Gas Turbine (CCGTs) secondary fuel start up tests for a period of time. A provision has been made for one test for the entire 2020/21 tariff year for all applicable units.

2.5.3. New Design Items

The new design items are covered in Section 2.2 - Supplementary Modelling Results.

2.5.4. Long Notice Adjustment Factors

The parameters associated with Long Notice Adjustment Factors have been set to zero for the first year of the revised SEM arrangements as per SEMC decision (SEM-17-046)12 and will be kept under review by the SEMC thereafter. As such no provision has been made in this forecast for the impact to Imperfections of Long Notice Adjustment Factors.

[12] https://www. committee.com/sites/semcommittee.com/files/media-files/SEM-17-046%20SEM%20Policy%20and%20Settlement%20%20Dispatch%20Parameters%20Decision.pdf

3. Uninstructed Imbalances

3.1 Overview of Uninstructed Imbalances

Uninstructed Imbalances [13] and constraint costs are related, with uninstructed imbalances having a direct effect on constraints costs, as TSOs re-dispatch generators to counteract the impact of uninstructed imbalances on the system.

All dispatchable generation is required to follow instructions from the control centres within practical limits to ensure the safe and secure operation of the power system. Deviation of a generating unit from its dispatch instruction will have a direct impact on system frequency and on the reserve available to the TSOs for frequency control.

Over-generation by a generating unit may result in a need for the TSOs to instruct other generating units down from their dispatched levels to lower levels in order to balance supply and demand. Significant over-generation can necessitate dispatching a generator off load to compensate. Under-generation by a generating unit may result in the need to instruct other generating units up from their dispatched levels to higher levels. In the event of unexpected or large under-generation by a generator the TSOs must act in a quick and decisive manner to restore appropriate system balance and reserve targets. This will generally necessitate dispatching on quick-start generators.

Uninstructed deviations therefore lead to increased constraint costs as the TSOs re-dispatch other generation at short notice. In SEM, the uninstructed imbalance mechanism provides the economic signals to ensure generators follow dispatch instructions and any net accrual of uninstructed imbalance payments offset the constraint costs that the uninstructed deviations gave rise to.

3.2 Forecasting Uninstructed Imbalances

It is assumed that the constraint costs of Uninstructed Imbalances (for over and under generation) will, on average, be recovered by the Uninstructed Imbalance payments for the forecast period.

Any incomings or outgoings are offset by the corresponding constraint costs due to action required by TSOs in response to Uninstructed Imbalances. As in previous submissions, an assumption is made that the current Uninstructed Imbalance mechanism sends the correct signals to generators and that all generators are fully compliant with dispatch instructions. As such, no provision for the constraint costs that would arise due to uninstructed deviations is included in this submission and a zero provision for Uninstructed Imbalances is forecast. In the event that uninstructed deviations occur within the tariff year, corresponding constraint costs will also arise.

[13] Uninstructed Imbalances occur when there is a difference between a Generator Unit's Dispatch Quantity and its Actual Output.

4. Testing Charges

The testing of generator units results in additional operating costs to the system in order to maintain system security. As a testing generator unit typically poses a higher risk of tripping, additional operating reserve will be required to ensure that system security is not compromised, which will give rise to increased constraint costs. The TSOs may need to commit extra units to ensure sufficient fast-acting units are available for dispatch to provide a rapid response to changes from the testing generator unit's scheduled output and to ensure that the system would remain within normal security standards following the loss of the generator unit under test. Additional constraint costs will arise whenever there is a requirement to increase the existing reserve requirement above the normal level on the system.

In SEM, Testing Charges are applied to generator units that are granted under test status.
The actual costs incurred that may be attributed to a testing generator unit are volatile and variable. As such, generators pay for the costs of testing based on an agreed schedule of charges. The Testing Tariffs, which are used to calculate the Testing Charges for each unit, have been set at a level that should, on average, recover the additional costs imposed on the power system during generator testing.

A zero provision has been made for the net contribution of Testing Charges, as any testing generator unit will pay Testing Charges to offset the additional constraint costs that will arise from out of merit running of other generators on the system as a result of the testing.

5. Other System Charges

Other System Charges (OSC) are levied on generators whose failure to provide necessary services to the system lead to higher Dispatch Balancing Costs and Ancillary Service Costs. OSC include charges for generator units which trip or make downward re-declarations of availability at short notice. Generator Performance Incentive (GPI) charges were harmonised between Ireland and Northern Ireland with the Harmonisation of Ancillary Service & Other System Charges "Go-live" on the 01/02/2010.

These charges are specified in the Charging Statements separately approved by the Regulatory Authorities (RAs) in Ireland and Northern Ireland. The arrangements are defined in both jurisdictions through the Other System Charges policies, the Charging Statements and the Other System Charges Methodology Statement.

As DBC and generator performance are intrinsically linked, Other System Charges are netted off DBC in SEM[14]. Since the introduction of Other System Charges, the performance of generators on the system has improved. It is assumed in this submission that generators are compliant with Grid Code and no charges are recovered through Other System Charges. As any deviation from this assumption will result in an increase in DBC, any monies recovered through Other System Charges will net off the resultant costs to the system in DBC. This assumption applies to the entire 2020/21 tariff year.

There are a number of reasons for having a zero provision for Other System Charges:

1. The TSOs assume all generators to be grid code compliant in the imperfections forecasting process. As Other System Charges are event based, it would be inappropriate to forecast them and could be deemed discriminatory;
2. If a generator unit trips or re-declares their availability down at short notice they are required to pay charges to compensate for not supplying the necessary services to the system. Such events would result in an increase in DBC. The TSOs assume that any revenue generated from Other System Charges covers some of the immediate short-term costs that arise as a result of these events; and
3. There is an additional cost associated with the unexpected loss of generation as the exact time the unit returns to service may be unknown and as such the TSOs may need to dispatch other generation to meet demand and reserve requirements. The market schedule, however, has perfect foresight of the unit trip and its outage duration. Therefore it can optimise the generation portfolio around this, for example starting another unit several hours before the trip. This disparity between the market and dispatch schedules result in an increase in DBC. The TSO's have included a provision for this in their forecasting submission under the subheading Perfect Foresight Effects. This is in line with previous years' submissions.

[14] Trading and Settlement Code V18.0, clause 4.155: "The purpose of the Imperfections Charge is to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Make Whole Payments, any net imbalance between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges over the Year, with adjustments for previous Years as appropriate."

6. Energy Imbalances

Energy imbalances that were considered a part of Imperfections in SEM are assumed to be managed by the new balancing market design, for the purposes of this submission. This will be monitored by the TSOs throughout the tariff year.

7. Fixed Cost Payments

Fixed Cost Payments (CFC) in the new market comprise of: Make Whole Payment, Recoverable Start Up Costs and Recoverable No Load Costs. A provision for the Fixed Cost Payments for the entire 2020/21 tariff year is included in this submission, based on the CFC estimate for the 2020/21 tariff year. The Recoverable Start Up Costs were already captured in the Plexos production cost difference so in order to avoid the double counting, the Recoverable Start Up part was subtracted from the total yearly estimate. TSOs recommend a provision of €15.38m for the Fixed Cost Payments.

8. Interconnector Ramp Rate Disparity

Under the revised SEM arrangements an imbalance volume and cost arise between differences in interconnector ramp rates in Euphemia (day ahead pricing algorithm currently in use throughout Europe) and real time operations. In general the higher the ramp rate in Euphemia the higher the imbalance volume and cost. For 2020/21 the TSOs recommended a provision of €1.6m for interconnector ramp rate disparity based on historic data.

Appendix 2: PLEXOS Modelling Assumptions

PLEXOS is used by the TSOs to forecast constraint costs. PLEXOS is a production costing 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.

The Transmission Network

These are the lines, cables and transformers operated by SONI and EirGrid. PLEXOS allows for the addition of new equipment, decommissioning of old equipment, up-ratings and periods when items are taken out of service.

Generation/Interconnection

There is a detailed representation of all generators in the PLEXOS model. This includes ramp rates, minimum and maximum generation levels, start-up times, reserve capabilities, fuel types and heat rates which are all modelled. Outages of generators, commissioning of new plant and decommissioning of old plant can all be represented.

Demand

Hourly variations in system demand are modelled down to the appropriate supply point.

Fuel Prices

Fuel prices for 2020/21 are defined in €/GJ based on the long term fuel forecasts from Thomson-Reuters Eikon[15] and data gathered by the TSOs. Carbon costs are also forecast and used, along with fuel costs, to simulate bids.
Detailed below are the key assumptions used in the PLEXOS modelling process:

General

Feature	Assumptions
Study Period	The study period is 01/10/2020 to 30/09/2021
Data Freeze	The input data for the PLEXOS model was frozen on 27/05/2020.
Generation Dispatch	Two hourly generation schedules are examined: one schedule to represent the dispatch quantities (constrained) and 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.
PLEXOS Version	7.5

[15] https://thomsonreuterseikon.com/

Demand

Feature	Assumptions
Regional Load	NI total load and IE total load are represented using individual hourly load profiles for each jurisdiction. Both profiles are at the generated exported level and include transmission and distribution losses and demand to be met by wind.
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.
Generator House Loads	These are accounted for implicitly by entering all generator data in exported terms.

Generation

Feature	Assumptions
Generation Resources	Conventional generation resources are based on the All-island Generation Capacity Statement 2019-2028.
Production Costs	Calculated through PLEXOS. The inputs to PLEXOS were based on analysis of actual bids. 1. Fuel cost (€/GJ) – forecasted for 2020/21 from Thomson Reuters and the US Energy Information Administration 2. Piecewise linear heat rates (GJ/MWh) 3. No Load rate (GJ/h) 4. Start energies (GJ) 5. Variable Operation & Maintenance Costs (€/MWh) A fixed element of start-up costs is calculated based on historical analysis of commercial offer data. The cost of European Union Allowances (EUAs) for carbon under the EU Emissions Trading Scheme (EU-ETS) are taken from ICE EUA Carbon Futures index.
Generation Constraints (TOD)	Based on the data in the PLEXOS Public Model for 2018-23[19] and Technical Offer Data in the SEM, the following technical characteristics are implemented: 1. Maximum Capacity 2. Minimum Stable Generation 3. Minimum up/down times 4. Ramp up/down limits 5. Cooling Boundary Times
Scheduled Outages	Draft outage schedules are used for 2020 and 2021maintenance outages
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates are based on EirGrid/SONI forecasts and Mean Times to Repair

Feature	Assumptions
	information is based on the 2020/21 Validated SEM Generator Data Parameters.
Hydro Generation	Hydro units are modelled using daily energy limits. Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled.
Priority Dispatch Generation	Wind generation resources are based on MW currently installed plus an anticipated rate of connection. The connection rate for 2020/21 tariff year is 337 MW of new installed wind. Solar generation resources are based on information from the Generation Capacity Statement 2019 - 2028. This indicates that there will be no increase in solar connection in Northern Ireland in 2020/21 tariff year. In Ireland there is assumed to be 80 MW of transmission connected controllable solar by 30/09/2021.
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,540MWh. The efficiency of the unit is modelled as 70% in the unconstrained and 48% in the constrained model.
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.
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.
Multi-Fuel Modelling	Only one fuel is modelled for each generating unit. The coal units at Kilroot, while able to run on oil, almost never do so, and will be modelled as coal only. Note that where units are multi fuel start this is modelled explicitly using one fuel offtake for each fuel. Multi fuel start units are Kilroot units one and two, Moneypoint units one, two and three and Tarbert units one, two, three and four.
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast based on actual flows derived from the new market.
Non-Synchronous Generation	System Non-Synchronous Penetration (SNSP) is set at 65% in the constrained PLEXOS model from Oct 2020. SNSP level increases to 70% in June 2021 as per best estimate of DS3 Programme Milestones as of May 2020.

Transmission

Feature	Assumptions
Transmission Data	The transmission system input to the model is based on data held by the TSOs.
Transmission Constraints	The transmission system is only represented in the constrained model. The market schedule run is free of transmission constraints.

Feature	Assumptions
Network Load Flow	A DC linear network model is implemented.
Ratings	Ratings for all transmission plant are based on figures from the TSOs' database.
Tie-Line	The North-South tie-line is not represented in the unconstrained SEM-GB model. The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 250 MW N-S and 300 MW S-N.
Interconnection	The Moyle Interconnector and EWIC are modelled.
Forced Outages	No forced outages are modelled on the transmission network.
Scheduled Outages	Major transmission outages likely to take place in the tariff year and which would impact on constraints are modelled.

Ancillary Services

Feature	Assumptions
Operating Reserve	Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled. Negative Reserve at night of 100MW in IE and 50MW in NI is modelled.
Reserve Characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.
Reserve Sharing	Minimum reserve requirements are applied to each jurisdiction, with the remainder being shared. These requirements are per the current reserve policy at the time of the data freeze[16]
Other Reserve Sources	For this forecast that DSUs, interconnectors and batteries will also provide reserve in the model.

[16] http://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Constraints-Update-Version-2019.pdf

Appendix 3: Transmission Outages

A list of the major outages, based on provisional outage schedules, which were used in the constrained model, is shown below.

Circuit/Plant	Date From	Date To
Aghada - Knockraha_220_1	06/04/2021	23/04/2021
Aghada - Knockraha_220_1	10/06/2021	08/07/2021
Aghada - Knockraha_220_2	26/07/2021	23/08/2021
Aghada - Raffeen_220_1	26/04/2021	08/06/2021
Aghada - Whitegate_110_1	01/03/2021	16/04/2021
Aughinish - Kilpaddoge_110_1	19/07/2021	31/08/2021
Ballynahulla - Knockanure_220_1	01/10/2020	27/11/2020
Ballynahulla - Knockanure_220_1	12/07/2021	03/09/2021
Ballyvouskil - Ballynahulla_220_1	06/09/2021	26/11/2021
Carrick on Shannon - Flagford_110_2	01/10/2020	25/11/2020
Carrigadrohid - Kilbarry_110_1	07/06/2021	26/07/2021
Carrigadrohid - Kilbarry_110_1	01/09/2020	17/11/2020
Castlebar - Cloon_110_1	03/05/2021	25/06/2021
Charleville - Killonan_110_1	18/08/2020	10/11/2020
Cloon - Lanesboro110_1	01/07/2021	31/08/2021
Corduff - Finglas_220_1	01/05/2021	10/06/2021
Cullenagh - Knockraha_220_1	01/03/2021	09/04/2021
Dunstown - Kellis_220_1	28/06/2021	10/07/2021
Dunstown - Moneypoint_380_1	01/03/2021	30/09/2021
Finglas - Huntstown_220_1	17/09/2020	07/12/2020
Finglas - North Wall_220_1	14/06/2021	30/07/2021
Flagford - Louth_220_1	04/05/2021	02/09/2021
Great Island - Kilkenny_110_1	06/04/2021	16/07/2021
Kellis - Kilkenny_110_1	19/07/2021	30/10/2021
Kilbarry - Knockraha_110_1	06/09/2021	11/10/2021
Kilbarry - Marina_110_1	01/08/2021	01/09/2021
Killonan - Knockraha_220_1	26/04/2021	14/06/2021
Killonan - Tarbert_220_1	01/10/2020	30/10/2020
Knockraha - Raffeen_220_1	01/03/2021	30/07/2021
Louth - Ratrussan_110_1	10/08/2020	12/10/2020

Louth coupler - a_220_1	01/08/2020	27/10/2020
Moneypoint - Oldstreet_380_1	01/10/2020	30/10/2020
Prospect - Tarbert_220_1	19/07/2021	10/09/2021
Shannonbridge Dallow-T_110_1	05/10/2020	16/11/2020
Ballylumford Eden ckt 1	01/04/2021	30/10/2021
Ballylumford Eden ckt 2	01/04/2021	30/10/2021
Coolkeeragh (COOL2A) - Magherafelt 275 ckt 1	01/04/2021	30/10/2021
Coolkeeragh (COOL2b) - Magherafelt 275 ckt 2	14/06/2021	21/06/2021
Coolkeeragh (COOL2b) - Magherafelt 275 ckt 2	16/08/2021	23/08/2021
Omagh to Dromore 110 ckt 1	17/07/2022	18/07/2022
Omagh to Dromore 110 ckt 2	17/07/2022	18/07/2022

Appendix 4: N-1's

A list of the N-1 contingencies which are utilised in the model is displayed below.

Loss of Aghada Glanagow 220
Loss of Aghada-Knockraha 1
Loss of Aghada-Knockraha 2
Loss of Aghada-Raffeen 1
Loss of Arklow Carrickmines 220
Loss of Arklow Lodgewood
Loss of Ballynahulla Knockanure
Loss of Ballyvouskil Ballynahulla
Loss of Ballyvouskil Clashavoon
Loss of Cashla Flagford
Loss of Cashla Prospect
Loss of Cashla Tynagh 220kV
Loss of CKM-Dunstown 220kV
Loss of CKM-Irishtown 220kV
Loss of CKM-Poolbeg 220 and PST
Loss of Clashavoon Knockraha 220
Loss of Clonee Corduff 220
Loss of Clonee Woodland 220
Loss of Corduff Finglas 220 1
Loss of Corduff Woodland 220 1
Loss of Cullenagh-Great Island 220
Loss of Cullenagh-Knockraha 220
Loss of Dunstown-Kellis 220
Loss of Dunstown-Maynooth 220 1
Loss of Dunstown-Turlough Hill 220
Loss of Finglas (or Belcamp) to Shellybanks 220
Loss of Finglas North Wall 220
Loss of Flagford-Louth 220
Loss of Flagford-Srananagh 220
Loss of Glanagow Raffeen 220
Loss of Gorman-Louth 220
Loss of Gorman-Maynooth 220
Loss of Great Island - Kellis 220
Loss of Great Island - Lodgewood 220
Loss of Inchicore Poolbeg 220 2
Loss of Inchicore-WestDublin 220 2
Loss of Inch-Irishtown 220

Loss of Irishtown Shellybanks 220
Loss of Killonan Knockraha 220
Loss of Killonan Shannonbridge 220
Loss of Killonan Tarbert 220
Loss of Kilpaddoge Knockanure 220 1
Loss of Kilpaddoge Moneypoint 220 1
Loss of Kilpaddoge Moneypoint 220 2
Loss of Kilpaddoge Tarbert 220 1
Loss of Knockraha-Raffeen 220
Loss of Louth Tandragee ckt 1 275 SC
Loss of Louth-Oriel (Woodland) 220
Loss of Maynooth Shannonbridge 220
Loss of Maynooth to (Ryebrook or) Woodland 220
Loss of Maynooth Turlough Hill 220
Loss of Maynooth-WestDublin 220 2
Loss of Moneypoint-Prospect
Loss of North Wall - Poolbeg
Loss of Oldstreet Tynagh
Loss of Oriel Woodland
Loss of Prospect-Tarbert
Loss of Agannygal Ennis
Loss of Agannygal Shannonbridge
Loss of Aghada Whitegate
Loss of Ardnacrusha Drumline
Loss of Ardnacrusha Ennis
Loss of Ardnacrusha Limerick
Loss of Ardnacrusha-Singland
Loss of Arklow Ballybeg
Loss of Arklow Banoge
Loss of Arva Carrick on Shannon
Loss of Arva Gortawee
Loss of Arva Navan
Loss of Arva Shankill 2
Loss of Athlone Lanesboro
Loss of Athlone Shannonbridge
Loss of Athy to Laois (or Portlaoise)
Loss of Aughinish Kilpaddoge
Loss of Ballybeg Carrickmines
Loss of Baltrasna Corduff
Loss of Baltrasna Hawkinstown (or Drybridge)
Loss of Bandon Dunmanway
Loss of Bandon Raffeen

Loss of Banoge to Tullabeg or Crane
Loss of Baroda Newbridge
Loss of Bellacorick-Castlebar
Loss of Bellacorick-Moy
Loss of Binbane Tievebrack
Loss of Binbane-CF
Loss of Booltiagh Ennis
Loss of Butlerstown Cullenagh
Loss of Cahir - Barrymore T
Loss of Cahir - Kill Hill
Loss of Cahir Tipperary
Loss of Cahir-Doon
Loss of Carlow Kellis 1
Loss of Carrick on Shannon - Arigna T
Loss of Carrick on Shannon - Flagford
Loss of Carrigadrohid Kilbarry
Loss of Carrigadrohid Macroom
Loss of Cashla Cloon
Loss of Cashla Dalton
Loss of Cashla Ennis
Loss of cashla galway 2
Loss of cashla salthill
Loss of Cashla to Shantallow or Somerset T
Loss of Castlebar Cloon
Loss of Castlebar Dalton
Loss of Cauteen Killonan
Loss of CF clogher 110kV - SPS Mulreavy
Loss of CF-Corraclassy
Loss of CF-Srananagh 2
Loss of Charleville Killonan
Loss of Clahane Tralee
Loss of Clahane Trien
Loss of Clashavoon Clonkeen
Loss of Clashavoon Macroom 1
Loss of Clashavoon Macroom 2
Loss of Clogher-Drumkeen
Loss of Clogher-Golagh T
Loss of Clonkeen Clashavoon
Loss of Clonkeen Knockearagh
Loss of Cloon Lanesboro
Loss of Coolroe Kilbarry
Loss of Corderry Arigna T

Loss of Corderry Srananagh
Loss of Corduff Blundelstown (or Mullingar)
Loss of Corduff GallanMucker (or Platin)
Loss of Corduff-Ryebrook
Loss of Corraclassy Gortawee
Loss of Crane Wexford
Loss of Cullenagh Rathnaskilloge (or Dungarvan)
Loss of Cullenagh to Mothel or Ballydine
Loss of Cullenagh-Waterford
Loss of Cunghill Sligo
Loss of Cushaling - Mount Lucas
Loss of Cushaling Newbridge
Loss of Cushaling Portlaoise
Loss of Derryiron Kinnegad
Loss of Derryiron Thornsberry
Loss of Derryiron Timahoe North (or Maynooth)
Loss of Drumkeen Letterkenny
Loss of Drumline Ennis
Loss of Drybridge Gorman
Loss of Drybridge Louth
Loss of Drybridge Platin
Loss of Dungarvan-Woodhouse
Loss of Dunmanway Macroom
Loss of Flagford-Sliabh Bawn
Loss of Flagford-Sligo
Loss of galway salthill
Loss of Gorman - Meath Hill
Loss of Gorman-Platin
Loss of Gorman-Navan 3
loss of Great Island - (Ballyfasy or) Kilkenny
loss of Great Island - Rosspile (or Wexford)
loss of Great Island - Waterford 1
Loss of Iniscara Macroom
Loss of Kellis Kilkenny
Loss of Kilbarry Knockraha 1
Loss of Kilbarry Mallow
Loss of kilbarry marina 2
Loss of Kill Hill - Thurles
Loss of Killonan-Limerick 1
Loss of Killonan-Limerick 2
Loss of Killonan-Singland
Loss of Kilpaddoge - Drombeg (or Tralee ckt 2)

Loss of Kilpaddoge Knockanure 1
Loss of Kilpaddoge Rathkeale
Loss of Kilteel Maynooth
Loss of Kilteel Monread
Loss of Kinnegad Clonfad (or Mullingar)
Loss of Kinnegad Dunfirth T
Loss of Knockraha - Barrymore T
Loss of Knockraha Woodhouse
Loss of Lanesboro Mullingar
Loss of Lanesboro-Sliabh Bawn
Loss of Letterkenny Golagh T
Loss of Letterkenny Tievebrack
Loss of Limerick Moneteen
Loss of Limerick Rathkeale
Loss of Lisdrum Louth
Loss of Lisdrum Shankill
Loss of Louth - Meath Hill
Loss of Louth - Ratrussan
Loss of Marina Trabeg 1
Loss of Marina Trabeg 2
Loss of Maynooth Blake T
Loss of Maynooth Rinawade
Loss of Maynooth Ryebrook
Loss of Mount Lucas - Thornsberry
Loss of Newbridge Blake T
Loss of Portlaoise Dallow T
Loss of Portlaoise Treascon Bracklone or Newbridge
Loss of Raffeen-Trabeg 1
Loss of Raffeen-Trabeg 2
Loss of Ratrussan Shankill
Loss of Rinawade Dunfirth T
Loss of Shannonbridge - Dalton T
Loss of Shannonbridge - Somerset T
Loss of Shannonbridge (or Lumcloon)- Ikerrin T
Loss of Sligo Srananagh 1
Loss of Tralee - Oughtragh T
Loss of AD 220-110 1
Loss of ARK 220-110 1
Loss of ARK 220-110 2
Loss of CLA 220-110 1
Loss of CLA 220-110 2
Loss of CSH 220-110 1

Loss of CSH 220-110 2
Loss of CUL 220-110 1
Loss of dn 380-220 1
Loss of dn 380-220 2
Loss of fla 220-110 1
Loss of fla 220-110 2
Loss of GI 220-110 1
Loss of GI 220-110 2
Loss of KLN 220-110 3
Loss of KLN 220-110 4
Loss of KPD 220-110 1
Loss of KPD 220-110 2
Loss of kra 220-110 1
Loss of kra 220-110 2
Loss of kra 220-110 3
Loss of Laois 400-110 1
Loss of LDG 220-110 1
Loss of LOU 220-110 1
Loss of LOU 220-110 2
Loss of MAY 220-110 1
Loss of MAY 220-110 3
Loss of MP 220-110 1
Loss of MP 380-220 1
Loss of MP 380-220 2
Loss of raf 220-110 1
Loss of raf 220-110 2
Loss of SH 220-110 1
Loss of wo 380-220 1
Loss of wo 380-220 2
Loss of dunstown laois 400
Loss of dunstown moneypoint 400
Loss of Moneypoint Oldstreet 400
Loss of Oldstreet Woodland 400
Loss of BAFD BCRM 275kV SC
Loss of BAFD HANA 275kV SC
Loss of BAFD KELL 275kV SC
Loss of BCRM HANA 275kV SC
Loss of CAST HANA 275kV SC
Loss of CAST TAND 275kV SC
Loss of CAST to KILR 275kV SC
Loss of Cool-magh 275 SC
Loss of KELL KILR 275kV SC

Loss of KELL MAGF 275kV SC
Loss of KILR to TAND 275kV SC
loss of MAGF TAMN 275 SC
loss of TAND TAMN 275 SC
Loss of COLE1- COOL1-
Loss of COLE1- LIMA1-
Loss of COLE1- Rasharkin
Loss of COOL1- KILL1-CL
Loss of COOL1- Limavady
Loss of COOL1- stra
Loss of DUNG to OMAH1-
Loss of Dungannon-Tamnamore
Loss of Gort Omagh
Loss of KELS1- RASH1-
Loss of Killmallaght Strabane
Loss of Omagh OmaS
Loss of Omagh Tremoge
Loss of OMAH1- STRA1-
Loss of Tamnamore Tremoge
Loss of BAFD 275 110 ckt 1
Loss of CAST 275 110 ckt 1
Loss of cool 275 110 ckt 1
Loss of kell 275 110 ckt 1
Loss of TAMN 275 110 ckt 1
Loss of TAND 275 110 ckt 1
Loss of Carrickmines - Poolbeg_220_1
Loss of Corduff - Finglas_220_2
Loss of Dunstown - Maynooth_220_2
Loss of Finglas - Belcamp_220_1
Loss of Inchicore - Maynooth_220_1
Loss of Inchicore - Poolbeg_220_1
Loss of Inchicore - WestDublin_220_1
Loss of Kilpaddoge - Moneypoint_220_3
Loss of Maynooth - WestDublin_220_1
Loss of Poolbeg - Shellybanks_220_1

Appendix 5: Glossary

AGU	Aggregated Generator Unit
ATR	Associated Transmission Reinforcements
CCGT	Combined Cycle Gas Turbine
CRU	Commission for Regulation of Utilities
DBC	Dispatch Balancing Costs
DSU	Demand Side Unit
EWIC	East West Interconnector
GB	Great Britain
GPI	Generator Performance Incentive
HILP	High Impact Low Probability
LPF	Load Participation Factor
MIUN	Modified Interconnector Unit Nomination
MSQ	Market Schedule Quantities
MW	Megawatt
MWh	Megawatt hour
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OSC	Other System Charges
RA	Regulatory Authority
RoCoF	Rate of Change of Frequency
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SMP	System Marginal Price
SO	System Operator
SSS	System Support Services
STAR	Short Term Active Response
T&SC	Trading and Settlement Code
TSO	Transmission System Operator
TUoS	Transmission Use of System
UUC	Unconstrained Unit Commitment
UR	Utility Regulator for Northern Ireland
VOM	Variable Operation and Maintenance

Appendix 6: SEM Settlement Cost Components

Dispatch Balancing Costs are made up of the following components:

CPREMIUM: Paid when an offer is scheduled in balancing (and delivered) at an offer price above the imbalance settlement price

CDISCOUNT: Paid when a bid is scheduled in balancing (and delivered) at a bid price below the imbalance settlement price

CABBPO/ CAOOPO: Bid Price Only and Offer Price Only Payments and Charges, 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

CCURL: Adjustment payment or charge to result in net settlement at a specific curtailment price for curtailment actions on generators.

CFC: 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.