Forecast Imperfections Revenue Requirement

For Tariff Year 2019/20

Version 1.0

Executive Summary

This submission represents the Transmission System Operators (TSOs) forecast of the revenue requirement to be recovered through the Imperfections Charge/Tariff during the 2019/20 tariff year.

The purpose of the Imperfections Charge/Tariff 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/Tariff however this is due to be provided later to capture the most up-to date information.

The forecast revenue requirement based on a number of assumptions and expected conditions for the 2019/20 tariff year period (01/10/2019 to 30/09/2020) is €302.65 million in nominal terms. This is an increase of €71.5m over the equivalent 2018/19 requirement of €231.17 million, of which €197.63m of this was approved when the final decision on Imperfection Charges was made.

Constraint costs represent the largest proportion of the forecast revenue requirement and this paper describes in detail the methodology employed in the forecasting process. The Go-Live date of the new SEM was 01/10/201; therefore a full year of data was not available at the time of the paper submission.

The approach taken in the 2019/20 forecast has been to use a PLEXOS model which assumes that the Dispatch Balancing costs in the new SEM are still based on the production cost difference between the unconstrained and constrained models. The post processing was done to capture all the new settlement cost components and this is included in the supplementary modelling task.

The key factors which have influenced the total constraint cost forecast for 2019/20 of €285.09 million (this figure excludes any estimate of Fixed Cost Payments) are:

- An increase in forecasted wholesale fuel costs of gas, distillate and carbon, a Dublin unit changing its gas contract as well as including Gas Transportation Capacity charges in its offers increased the constraint costs by approximately €38 million in the PLEXOS model
- Northern Ireland units including Gas Transportation Capacity charges in their offers increased the PLEXOS model by €18 million
- An increase in available priority dispatch generation in the unconstrained PLEXOS model contributes to an additional Imperfections cost of €29 million compared to the 2018/19 forecast
- A provision of €19.05 million for the exposure to the new imbalance pricing design in the new market calculated through CPREMIUM and CDISCOUNT
- A provision of €14.42 million for the settlement of pump storage units in the new market

- Forecast Demand Increase reduced the PLEXOS model constraint costs by €23 million
- Higher flows on the Interconnectors and the N-S Tie Line along with Operational Constraints improvements have reduced the PLEXOS model constraint costs by €19 million

The main components of the 2019/20 forecast revenue requirement submission are set out in the table below:

Component	Forecast (€ million)
PLEXOS Modelling	**234.57**
Supplementary Modelling	**50.52**
Interconnector Ramp Rate Disparity	**3.2**
Fixed Cost Payments	**14.35**
Total 2019/20 Forecast Imperfections Revenue Requirement	**302.65**

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.

The submission reflects the TSOs' forecast of the revenue required from the Imperfections Charge/Tariff for the 12 month period from 01/10/2019 to 30/09/2020 inclusive, referred to as the tariff year 2019/20.

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 the new SEM can be broken down in CPREMIUM, CDISCOUNT, CABBPO, CAOOPO and CCURL. The new cost component definitions are provided in Appendix 6. In addition to DBC, the forecast also makes provision Fixed Cost Payments, and Other System Charges for the tariff year 2019/20. Other elements also contribute in setting the regulated Imperfections Charge/Tariff including the Imperfections K factor, which adjusts for previous years as appropriate, and the forecast system demand.

The resulting Imperfections Charge/Tariff 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 €302.65 million in nominal terms for the tariff year 2019/20. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Context for Tariff Year 2019/20

There are a number of factors which may influence the forecast costs, and hence the Imperfections revenue requirement, for the tariff year 2019/20. The most significant influencing factors are described in the following sections.

Uncertainties and limited experience associated with the new market make the 2019/20 forecast more challenging. . This increases the risk of Imperfections charges not being sufficient to pay for actual costs when they arise. In turn this places greater financial pressure on the TSOs to ensure they are in a position to finance any underfunding should this be the case. Section 4 and section 5 deal with this issue in greater detail.

1.1.1 Background of the SEM

The wholesale electricity market arrangements for Ireland and Northern Ireland were recently revised under the I-SEM Project with the new SEM 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 assetless 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 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 2019/20

The new 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 in the first 6 months has been very 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 new SEM 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 were represented by their unit complex incremental offers in the model, while the other three types were captured in post processing.

1.1.3 Generation Merit Order

Compared to the tariff year 2018/19 forecast, there has been a change in the generation mix available in the market. Similar to trends seen in recent years there is a large 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.
In combination with this, there is an increase in forecast wholesale fuel prices for 2019/20, Figure 1 outlines the differences in the forecast fuel prices from the 2018/19 forecast to the 2019/20 forecast, so this makes the cost of constraining on this 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 DBC.

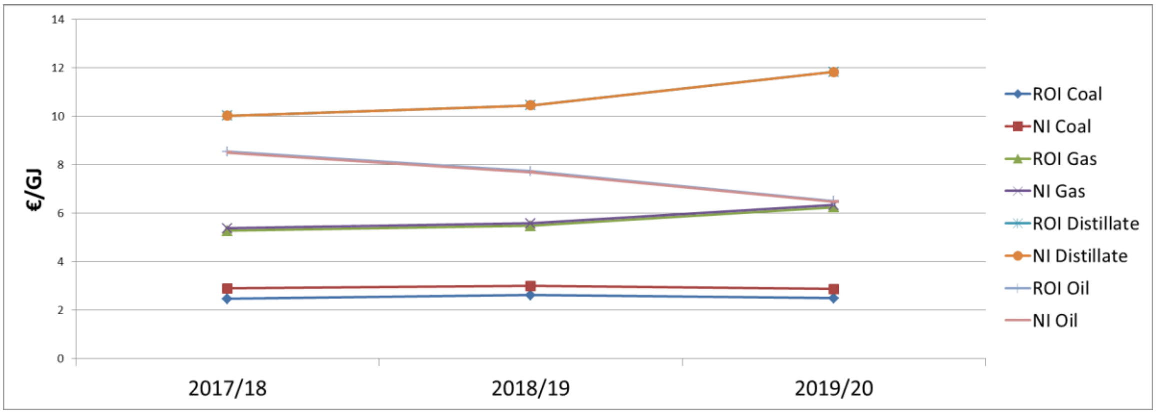

Figure 1: Forecast Model Fuel Cost Changes from 2018/19 to 2019/20

It has been assumed, that a gas-fired generation unit in Ireland and four gas fired generators in Northern Ireland will now include the cost of particular gas network capacity products into 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 where they are constrained on in dispatch to meet reserve, transmission or security constraints on the power system.

1.1.4 Interconnection

Since the increase in the Carbon Price Floor in Great Britain (GB) in April 2015, market interconnector flows on both Moyle and the East West Interconnector (EWIC) have resulted in the price spread between SEM and GB narrowing significantly. This increase in Carbon Price Floor has resulted in significant exports from SEM during the night and then imports, albeit at a reduced level, to SEM during the day. There has also been an increase in the number of market participants registered to trade on both interconnectors. The result of this is that there is greater trading on both interconnectors based on price spreads and this can be clearly seen during periods of high wind in SEM.

The TSOs have developed a number of different interconnector profiles which are a function of wind on the system. They are based on the actual interconnector market flows from October 2018 to Dec 2018. Figures 2 and 3 show the flows used for EWIC and Moyle for the 2019/20 tariff year. In general, the profiles for EWIC show higher exports from SEM to GB overnight and when wind levels are high and lower exports or imports at times when wind is low, mostly during the day.
Moyle exports were only limited to 83MW export for the first 2 months of the 2019/20 tariff year. The capacity increased from Dec 2019 as per the Moyle Interconnector Limited Interconnector Capacity Calculation[1].

Interconnector flows have been described in the Risk Factors section (Section 3.1.3) of this submission. For clarity, flows below the x-axis represent exports from SEM to GB and flows above the x-axis represent imports from GB to SEM.

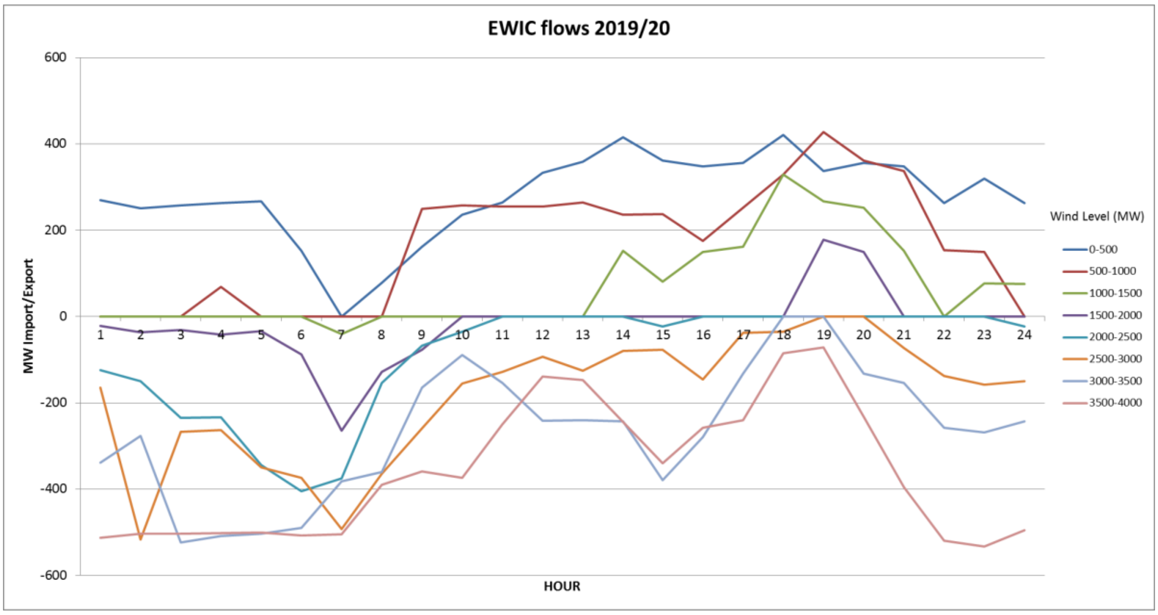

Figure 2: Market Interconnector Flows used for EWIC

[1] http://www.mutual-energy.com/wp-content/uploads/downloads/2017/06/Moyle_Capacity_Calculation_2017_consultation_web.pdf

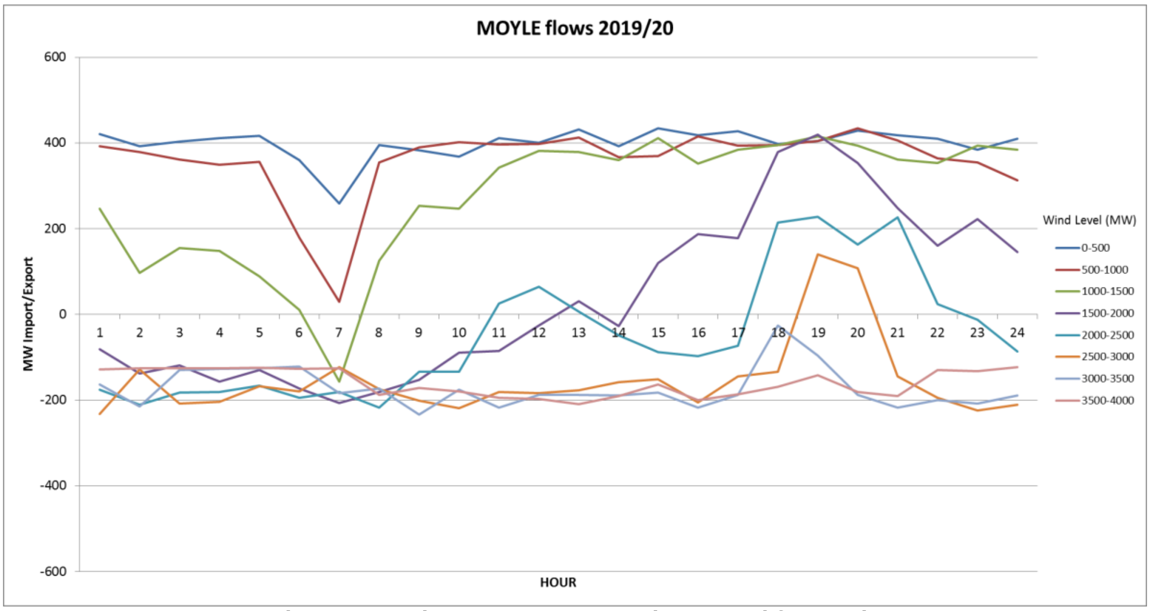

Figure 3: Market Interconnector Flows used for Moyle

1.1.5 System Operator Countertrading

For the 2019/20 forecast, countertrading has been disabled in the constrained model for EWIC and Moyle. This assumption is based on the experience of the first six months of the new market 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 new SEM

2. Forecast Constraint Costs

This section contains the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2019/20, 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 2019/20 tariff year0 is **€234.57 million**. For reference the PLEXOS cost for 2018/19 was €149.98 million. Separate provisions which cannot be modelled in PLEXOS have been captured in the supplementary modelling, described in section 2.2.2 below.

The most significant influences on forecast constraint costs, compared to 2018/19, in the PLEXOS model are:

- An increase in wholesale fuel prices, a Dublin unit changing its gas contract as well as including Gas Transportation Capacity charge increases constraints by €38 million
- Northern Ireland units including gas product charges in their offers results in a €18 million increase
- An update of conventional and peat and waste priority dispatch offer prices increase costs by €17 million
- An increase in available priority dispatch generation in the unconstrained PLEXOS model contributes to an additional €29 million
- Updated 2019/20 Transmission outages contribute to additional €8 million increase
- An increased SNSP levels contribute to €8 million increase
- Generator and Interconnector Outages contribute to €10 million increase
- A demand increase contributes to a reduction of €23 million
- Revised Interconnector Flows and Moyle export cap removal contribute to a reduction of €4 million
- Revised N-S Tie Line flows, Inertia Reduction and other Operational Constraints updates result in €15 million reduction

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 2019/20 is **€50.52 million**. This represents a reduction of €16 million from the 2018/19 tariff year.

Note that some parts of 2018/19 supplementary modelling are now included in the PLEXOS model this year. Caution must therefore be taken in comparing the cost differentials between the supplementary modelling for 2018/19 and 2019/20 forecasts.

The largest influences on the changes to supplementary modelling are:

Additional PREMIUM and DISCOUNT Payments and Imbalance Price Impact: The imbalance price in the new SEM 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 €19.05 million has been calculated within supplementary modelling for the entire 2019/20 tariff year. It is important to note that this impact could in fact be higher than this provision as the imbalance prices assumed for this calculation used actual imbalance price of the first 6 months of the new market. With the MWR Locational Constraints Removal and other potential changes to the pricing rules, the average imbalance price could in fact be higher than historical price because more units could potentially be settled on their simple offers.
This impact was calculated by applying the settlement calculation for the two highest settlement cost components PREMIUMS and DISCOUNTS. The calculation was done by multiplying the dispatch volume difference between the two models and the generator offer price if the offer price was better than the imbalance price. The model SRMC were replaced with the actual average complex decremental prices if the generators were mostly dispatched down/off in the constrained model. To account for the simple price offers, the premiums and discounts were calculated again, however this time we looked at the difference between the actual simple offers and the model SRMC to avoid the double counting from the previous step.

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 they clear in the Day-Ahead market and subsequently differs from their Physical Notifications (PNs) in the Balancing Market. Thus there are high PREMIUMS and DISCOUNTS the TSOs pay out to pump units. Another considerable difference is the offer prices associated to pump units in the old market compared to the new market. Pump 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 PREMIUM and DISCOUNT payments the pump storage units received in the first six months of the new SEM and then extrapolated for a full year.

CABBPO/CAOOPO 'Undo' Actions: CABBPO and CAOOPO are two new settlement cost components in the new SEM for the 'Undo' actions, the main intent of which is to ensure units gain some compensation for energy bought at the instructions of the TSOs 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 provision of €5.7 million for this is based on the spent for the first 6 months on those two components.

MWR 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. Given that this modification was only implemented on 2 May 2019, there was very little settled data to include in impact analysis for this forecast. As such an estimate was carried out using the following methodology. A one week period was analysed to find the trading periods where generators were flagged out due to the MWR constraint binding. From this set of data the periods when these generators were NIV tagged were removed from the analysis. An estimated settlement calculation was carried out for the remainder of the periods for these generators in order to see the cost of paying them at the better of their weighted average Simple Offer prices and the imbalance price. This was then extrapolated for a full year. However consideration was given to the fact that the implementation of this modification would remove the instance of an event like that of 24 January 2019 so the imperfections cost of this event was subtracted from the estimate calculated above.

Constrained Wind: Wind is not paid for curtailment in the new market any more, however it is still paid for constraints. Because the wind in PLEXOS model has a price of 0 €/MWh, the provision of €3 million is included within supplementary modelling. This figure is based on the actual CDICOUNTS wind participants received in the first 6 months of the new SEM and extrapolated for the whole tariff year.

Interconnector Ramp Rate Disparity: In the new SEM 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. In 2018/19 the TSOs recommended a provision of €8 million in their Imperfections revenue requirement submission that was based on preliminary analysis of this issue at the time of data freeze, at which point there was no actual balancing market data. For the 2019/20 Imperfections Forecast there is empirical data available and this was used to calculate a provision of €3.2 million.

Long Notice Adjustment Factors: For the 2019/20 forecast a decision had not yet been made on the setting for the Long Notice Adjustment Factor (LNAF) related parameters. The decision was subsequently made to set these to zero for the new market (SEM-17-046). A provision of zero was therefore made for the 2019/20 forecast.

[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 2019/20

A number of items were removed from supplementary modelling for 2019/20. These are outlined in the table below:

Description	Notes
System Operator Interconnector Trades - Frequency Service	No countertrading
System Operator Interconnector Trades - Priority Dispatch	No countertrading
System Operator Interconnector Trades - System Security	No countertrading
Dispatch Down Cost of DSUs	Included in Plexos
Imbalance Price Impact	Included in 'Additional PREMIUM and DISCOUNT Impact'
Northern Ireland Gas Product Charges	Included in Plexos

The results of all elements of the modelling process in 2019/20 are summarised in the table below:

Description	19/20 Forecast (€m)
PLEXOS Modelled Constraints for 12 Months	234.57
Additional PREMIUM and DISCOUNT Impact	19.05
Dispatch of Pump Storage Units	14.42
CABBPO/CAOOPO ('Undo' Actions)	5.70
MWR removal	4.66
Block Loading	0.06
Capacity Testing & Performance Monitoring	2.58
Secondary Fuel Testing	1.06
Constrained Wind	3.00
Supplementary Modelling Total	50.52
Total Constraint Costs	285.09

2.3 Imperfections Charges – other components

In addition to the €285.09 million 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	**285.09**
- Constraints	**285.09**
- Uninstructed Imbalances [3]	**0.0**
- Testing Charges [4]	**0.0**
Fixed Cost Payments [5]	**14.35**
Interconnector Ramp Rate Disparity	**3.2**
Other System Charges	**0.0**
FORECAST IMPERFECTIONS REVENUE REQUIREMENT	**€302.65**

[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 2019/20 tariff year is included in this submission, based on the forecast Fixed Cost Payment for the next tariff year.*

3. Risk Factors

A large number of risk factors should be considered when assessing the Imperfections Revenue requirement for 2019/20. 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.

3.1 Specific Risks

3.1.1 The new SEM Design

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 (e.g. a move to Simple NIV Tagging) at the time of data freeze have not been accounted for and would only become clear following their implementation in the new market.

3.1.2 Delays and Overruns of Outages

Similar to previous years there is a significant programme of capital works scheduled to take place on the transmission system during the 2019/20 tariff year which is in turn resulting in an increase in DBC. This programme of works is in line with published Associated Transmission Reinforcements (ATRs). 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 and overrun of any outage will extend this state of reduced flexibility and may result in an increase in DBC. The outage requirements for the 2019/20 tariff year are based on best available information and there is a significant risk of delays to the start dates and overruns on these scheduled dates which are predominately outside of the control of the TSOs. The TSOs have carried out a desktop exercise of the indicative transmission outages scheduled to take place during the 2019/20 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.

3.1.3 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.

3.1.4 Interconnector Flows and System Operator Countertrading

Market interconnector flows have been forecast using historical data from the new SEM from 01/10/2018 to 31/12/2018. Participant behaviour could result in interconnector flows that differ greatly from those forecasts. This, in turn, could result in constraint costs changing significantly. The TSOs will closely monitor the forecast flows against actual market Interconnector flows during the tariff year.

3.1.5 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 March 2018, 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. If fuel prices increase significantly this will increase DBC in two ways. First the cost of constraining on generators will increase and second it could change the direction of market interconnector flows from GB to SEM. Both these factors could increase DBC.
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.

3.1.6 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.

3.1.7 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. The new capacity market in SEM could impact on generator availability and therefore have a knock on effect on DBC.

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.

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. In the new SEM, 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 TSO 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

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[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

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 Modifications to the SEM Trading and Settlement Code – Part B

All assumptions made in this submission were based on the current version of the Market Rules as outlined in the latest version of the Trading and Settlement Code Part B (dated 7 April 2017). The impact of future rule changes has not been considered and must be deemed a potential risk.

3.1.15 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 adequate, and additional security constraints may be required, resulting in an increase in constraint costs.

3.1.16 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. This is over and above the SO interconnector trading described in section 2.2.

3.1.17 Increased Connection of Priority Dispatch Generation

There is a significant amount of priority dispatch generation, in particular wind and solar, contracted to connect during the 2019/20 tariff year. The TSOs have forecast the amount of wind which they anticipate will connect during the tariff year. If there is an increase in rate of connection this will most likely increase DBC because more expensive generation might be constrained on by the TSOs for non-energy actions in the Balancing Market. The TSOs will keep this under review.

3.1.18 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. The impact of this directive on combustion plants is discussed in section 3.3 of the All Island Generation Capacity Statement 2016-2025.[7]
A provision for costs arising from this has not been included in the 2019/20 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.

Another important 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 TSOs have included no additional Brexit-specific aspects.

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

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 2019 to 30 September 2020.

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. This is particularly critical given the scale of overrun being seen on Imperfections Costs relative to what is being recovered during the 2018/19 tariff year to date.

As is currently the case, 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.

While EirGrid and SONI have standby debt facilities in place to cover revenue shortfalls, we are currently seeing significant pressures on these facilities largely driven by the Imperfections Costs overrun. 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 in the new SEM 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[8].

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 for Part A (version 20) and Part B dated 7 April 2017.
- 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

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

further summary of the PLEXOS modelling and associated assumptions is provided in Appendix 2.

Subject	Assumption
Data Freeze	All input data for the PLEXOS model was frozen at 18/04/2018.
Forecast Period	The forecast period is from 01/10/2019 to 30/09/2020.
Currency	All costs are modelled in euro.
Fuel and Carbon Prices	Fuel prices for 2019/20 are based on the long term fuel forecasts from Thomson-Reuters Eikon[9], the US Energy Information Administration[10] 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[11].
Demand Forecast	The demand is based on the 2019/20 median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2018-2027[12]. An adjustment was made to the demand forecast to 2019/20 to account for the fact that a certain level of embedded generation were transferring to registering as Demand Side Units (DSUs).
Generator Schedule Outages	2019 and 2020 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.

[9] https://thomsonreuterseikon.com/
[10] https://www.eia.gov/
[11] The Bidding Code of Practice - AIP-SEM-07-430
[12] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf

Transmission Scheduled and Forced Outages	A number of significant indicative scheduled transmission outages for 2018 and 2019 are modelled in PLEXOS. Forced transmission outages are not modelled.
Operating Reserve	Primary, secondary and tertiary 1 and 2 reserve requirements are modelled[13]. 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 300 MW N-S and 125 MW S-N. This assumption has been updated from previous years based on TSO operational experience.
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast to be predominantly imports into SEM during the day and exports into GB during the night. This reflects historical experience of flows on both interconnectors prior to the data freeze and is a best estimate of likely future flows.
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.

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

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 2019/20 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 new SEM as per SEMC decision (SEM-17-046)14 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.

[14] 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 [15] 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.

[15] 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[16]. 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 2018/19 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.

[16] 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 2019/20 tariff year is included in this submission, based on the CFC estimate for the 2019/20 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 €14.35 million for the Fixed Cost Payments.

8. Interconnector Ramp Rate Disparity

In the new SEM 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. In 2018/19 the TSOs recommended a provision of €8 million in their Imperfections revenue requirement submission that was based on preliminary analysis of this issue at the time of data freeze, at which point there was no actual balancing market data. For the 2019/20 Imperfections Forecast there is empirical data available and this was used to calculate a provision of €3.2 million.

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 2019/20 are defined in €/GJ based on the long term fuel forecasts from Thomson-Reuters Eikon[17] 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 01/10/2019 to 30/09/2020
Data Freeze	The input data for the PLEXOS model was frozen on 18/04/2018
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	7.3 Revision 4
Model Reference	1819 forecast

Demand

Feature	Assumptions

[17] https://thomsonreuterseikon.com/

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 2018-2027[18]. Historical analysis on generators' declared availability was carried out and some units seasonal ratings were adjusted based on this.
Production Costs	Calculated through PLEXOS using the Regulatory Authorities' publicly available dataset: SEM PLEXOS Public Model for 2018-23[19]. 1. Fuel cost (€/GJ) – forecasted for 2019/20 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 The capping of the Maximum Generation based on the

[18] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf
[19] https://www.semcommittee.com/publications/sem-18-175-sem-plexos-model-validation-2018-2023-information-paper

Feature	Assumptions
	contracted Maximum Export Capacity (MEC) in Ireland per the CRU Decision[20] was not implemented due to this decision being deferred.
Scheduled Outages	Draft outage schedules are used for 2019 and 2020 maintenance 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 information is based on the 2018/19 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 based on EirGrid Capacity Register. The connection rate for 2019/20 tariff year is 350 MW of new installed wind. Solar generation resources are based on information from the Generation Capacity Statement 2018 - 2027[21]. This indicates that there will be no increase in solar connection in Northern Ireland in 2019/20 tariff year. In Ireland there is assumed to be 50 MW of transmission connected controllable solar by 30/09/2020.
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 to be predominantly imports into SEM during the day and exports into

[20] CRU/14/047 – Decision on Installed Capacity Cap
[21] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf

Feature	Assumptions
	GB during the night. This reflects historical experience of flows on both interconnectors prior to the data freeze and is a best estimate of likely future flows.
Non-Synchronous Generation	System Non-Synchronous Penetration (SNSP) is set at 70% in the constrained PLEXOS model from Oct 2019. SNSP level increases to 75% in February 2020 as per DS3 Programme Transition Plan Q4 2018 – Q4 2020[22]

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.
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[23]

[22] http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Programme-Transition-Plan-Q4-2018-Q4-2020-Final.pdf
[23] http://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Constraints-Update-Version-2019.pdf

Other Reserve Sources	Static reserve provided by STAR (an interruptible load scheme) was discontinued in April 2018. However it is assumed for this forecast that demand and embedded generation providing the reserve will continue under other arrangements. The PLEXOS model does not distinguish between dynamic and static reserve on the interconnectors. Moyle is modelled as providing 73 MW and EWIC 68 MW of reserve.

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
Athea	04/11/2019	16/11/2019
Boggeragh	19/10/2019	31/10/2019
Derrybrien	20/04/2020	26/04/2020
Dromada	04/11/2019	16/11/2019
Agannygal - Shannonbridge_110_1	10/04/2020	15/04/2020
Aghada - Raffeen_220_1	10/08/2020	15/08/2020
Ardnacrusha - Ennis_110_1	20/06/2020	23/06/2020
Arva - Carrick on Shannon_110_1	01/06/2020	03/06/2020
Arva - Shankill_110_1	05/06/2020	08/06/2020
Arva - Shankill_110_2	10/06/2020	12/06/2020
Athy - Portlaoise_110_1	01/09/2020	10/10/2020
Ballynahulla - Knockanure_220_1	01/06/2020	01/10/2020
Baltrasna - Corduff_110_1	25/08/2020	01/09/2020
Bellacorick - Castlebar_110_1	11/10/2019	15/10/2019
Binbane - Cathaleens Fall_110_1	18/06/2020	18/08/2020
Binbane - Letterkenny_110_1	07/10/2019	18/10/2019
Binbane - Letterkenny_110_1	01/06/2020	16/06/2020
Carrigadrohid - Kilbarry_110_1	01/03/2020	20/04/2020
Cashla - Dalton_110_1	04/10/2019	10/10/2019
Cashla - Ennis_110_1	01/04/2020	06/04/2020
Cashla - Prospect_220_1	20/03/2020	25/03/2020
Cashla - Prospect_220_1	05/06/2020	09/06/2020
Cashla - Salthill_110_1	01/06/2020	01/07/2020
Castlebar - Dalton_110_1	10/05/2020	01/07/2020
Cathaleens Fall - Srananagh_110_1	20/04/2020	22/04/2020
Clashavoon - Clonkeen_110_1	01/03/2020	01/05/2020
Cloon - Lanesboro110_1	29/10/2019	02/11/2019
Cloon - Lanesboro110_1	10/05/2020	20/07/2020
Corderry - Srananagh_110_1	01/03/2020	01/05/2020
Corduff - Platin_110_1	25/07/2020	01/08/2020
Corduff - Ryebrook_110_1	01/10/2019	01/11/2019
Crane - Wexford_110_1	01/06/2020	20/07/2020
Cullenagh - Great Island_220_1	01/07/2020	06/07/2020
Drumline - Ennis_110_1	10/06/2020	13/06/2020
Dungarvan - Woodhouse_110_1	01/08/2020	15/08/2020
Dunmanway - Macroom_110_1	07/10/2019	21/10/2019

Dunmanway - Macroom_110_1	25/10/2019	29/10/2019
Dunstown - Moneypoint_380_1	01/06/2020	26/06/2020
Flagford - Louth_220_1	01/06/2020	10/07/2020
Flagford - Sligo_110_1	04/11/2019	13/11/2019
Glenree Moy_110_1	01/03/2020	01/07/2020
Great Island - Kilkenny_110_1	01/04/2020	10/08/2020
Great Island - Waterford_110_2	04/11/2019	16/11/2019
Great Island - Wexford_110_1	01/07/2019	10/10/2019
Great Island - Wexford_110_1	04/10/2019	07/10/2019
Great Island - Wexford_110_1	04/11/2019	16/11/2019
Inchicore - Maynooth_220_1	01/10/2019	10/11/2019
Inchicore - Maynooth_220_2	10/10/2019	20/10/2019
Inniscarra - Macroom_110_1	07/10/2019	21/10/2019
Inniscarra - Macroom_110_1	25/10/2019	30/10/2019
Kilbarry - Marina_110_1	30/04/2020	30/05/2020
Killonan - Limerick_110_2	01/04/2020	01/05/2020
Killonan - Tarbert_220_1	01/03/2020	20/04/2020
Kilpaddoge - Rathkeale_110_1	01/04/2019	05/04/2019
Knockraha - Raffeen_220_1	01/08/2020	25/08/2020
Louth - Ratrussan_110_1	01/03/2020	01/07/2020
Maynooth - Shannonbridge_220_1	10/10/2019	16/10/2019
Maynooth - Woodland_220_1	26/09/2019	01/11/2019
Moneypoint - Oldstreet_380_1	20/03/2020	01/05/2020
North Wall - Poolbeg_220_1	21/10/2019	26/10/2019
Shannonbridge Somerset-T_110_1	09/10/2019	22/10/2019
Sligo - Srananagh_110_1	20/10/2019	02/11/2019
Tarbert - Tralee_110_1	01/03/2019	01/08/2019
Clashavoon T2101 cmc was 125	01/09/2019	01/11/2019
Great Island T2102	04/11/2019	16/11/2019
Great Island T2102	01/05/2020	10/05/2020

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

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: New 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.