Forecast Imperfections Revenue Requirement

For Tariff Year 2018/19

Version 2.0

Executive Summary

This submission represents the Transmission System Operators (TSOs) forecast of the revenue requirement to be recovered through Imperfections Charge/Tariff during the 2018/19 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 2018/19 tariff year period (01/10/2018 to 30/09/2019), which is the first year of the Integrated Single Electricity Market (I-SEM) is €231.17 million in nominal terms. This is an increase of €17.68m over the equivalent 2017/18 requirement of €213.49 million, of which €180.36m 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 I-SEM is 01/10/2018 therefore this forecast is for an entire tariff year of the new market design. The approach taken in the underlying forecast has been to use a PLEXOS model which assumes that the Dispatch Balancing Costs in I-SEM will remain based on the production cost difference between the unconstrained and constrained models. There are also a number of additional assumptions and considerations which cannot be calculated using PLEXOS so these have been completed using supplementary desktop modelling. It is important to note that due to the high number of unknowns associated with I-SEM at this stage, in many cases the TSOs had to make high level assumptions (where possible) to estimate these new cost drivers.

The key factors which have influenced the total constraint cost forecast for 2018/19 of €215.98 million (this figure excludes any estimate of Fixed Cost Payments and the provision for the Interconnector Ramp Rate Disparity) are:

- A provision of €45.54 million for the exposure to the new imbalance pricing design for non-energy actions in I-SEM.
- An increase in available priority dispatch generation in the unconstrained PLEXOS model of 9% contributes to an additional €17 million compared to the 2017/18 forecast.
- An increase in forecasted wholesale fuel costs increases constraint costs by approximately €8 million in the PLEXOS model.

- An improvement in generator parameters through the introduction of the TSOs' System Services contracts contributes to a reduction of €49 million compared to the 2017/18 forecast. However, there was no updated commercial offer data associated with lower minimum loads to use in this analysis and as such the actual impact of this could be lower in actual outturn terms, which is a risk.
- In I-SEM wind generation that is constrained or curtailed down from their market position will have to pay back either their ex-ante market revenue or the imbalance settlement price rather than retaining their revenue under the SEM, resulting in additional charges which can offset DBC leading to a reduction of the forecast of €8.9 million.

The main components of the 2018/19 forecast revenue requirement submission are set out in the following table:

Component	Forecast (€ million)
PLEXOS Modelling	**149.48**
Supplementary Modelling	**66.50**
Fixed Cost Payments	**7.19**
Interconnector Ramp Rate Disparity	**8.00**
Total 2018/19 Forecast Imperfections Revenue Requirement	**231.17**

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 01/10/2018 to 30/09/2019 inclusive, referred to as the tariff year 2018/19.

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. In addition to DBC, the forecast also makes provision Fixed Cost Payments, the impact to DBC on of the Interconnector Ramp Rate Disparity and Other System Charges for the tariff year 2018/19. 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 Integrated Single Electricity Market (I-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 €231.17 million in nominal terms for the tariff year 2018/19. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Context for Tariff Year 2018/2019

There are a number of factors which may influence the forecast Constraint costs, and hence the Imperfections revenue requirement, for the tariff year 2018/19. The most significant influencing factors are described in the following sections.

The uncertainties associated with the introduction of I-SEM makes the 2018/19 forecast particularly difficult to ascertain. 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 I-SEM

The I-SEM is a new wholesale electricity market arrangement for Ireland and Northern Ireland. 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 is based on continuous cross border trading. However, at go-live, intraday trading is only continuous within the 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 2018/19

The I-SEM arrangements are due to go live on 01/10/2018 which introduces a large number of unknowns into this forecasting process. Unknown factors associated with I-SEM include the imbalance price, the incremental and decremental prices of generators and the Physical Notifications (PNs) of generators. It is assumed for the purposes of the PLEXOS modelling used for this forecast that generator offers in I-SEM will continue to be based on their short run marginal costs. The reason for this is that without actual data to go on an assumption needs to be made on what generator PNs and dispatch positions will be. Using the current short run marginal costs of generators in SEM to approximate their PNs and dispatch positions in I-SEM is the most reasonable approach at the time of data freeze of this submission. In addition to PLEXOS modelling the TSOs have estimated the potential impact to Imperfections of specific I-SEM related factors for tariff year 2018/19 within supplementary modelling.

1.1.2 Generation Merit Order

Compared to the tariff year 2017/18 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. Compared to 2017/18 there is over 9% more priority dispatch generation available to the PLEXOS model in the 2018/19 forecast. 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 2018/19, Figure 1 outlines the differences in the forecast fuel prices from the 2016/17 forecast to the 2018/19 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.

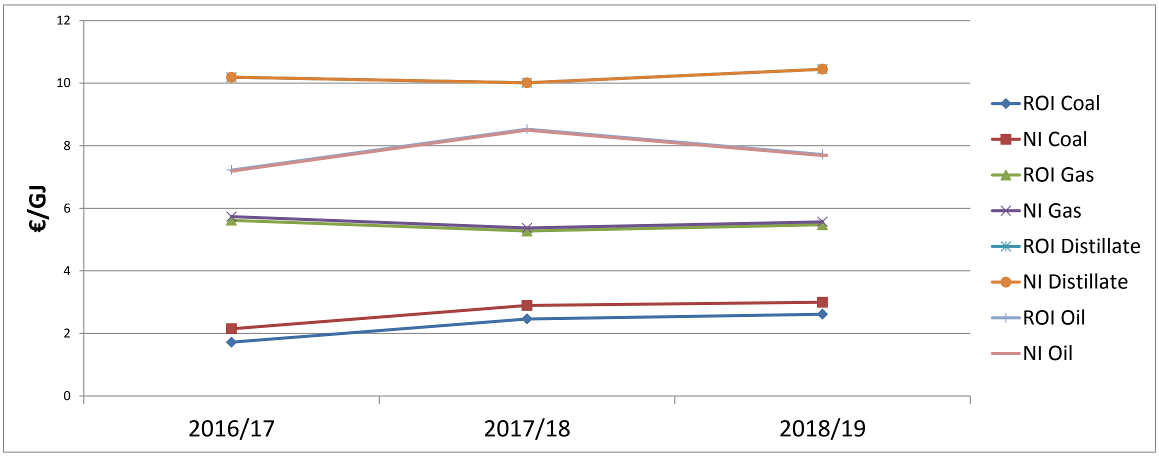

Figure 1: Forecast Model Fuel Cost Changes from 2016/17 to 2018/19

It has been assumed, based on the recent participant bidding behaviour that eleven gas-fired generation units in Ireland and five gas fired generators in Northern Ireland will continue to 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. Note that the GTC for the Northern Ireland generators has been calculated through the analysis for the 2016/17 Imperfections Cost Incentive using actual outturn costs. This is because these NI generators typically increase their offers from the ex-ante to the within day gates and PLEXOS cannot accurately model this.

1.1.3 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 to reflect the different flows for weekdays, weekends, low wind periods and high wind periods based on interconnector market flows from October 2017 to March 2018. Figures 2 and 3 show the flows used for EWIC and Moyle for the 2018/19 tariff year. In general, the profiles for EWIC show higher imports from GB to SEM by day and slightly lower exports from SEM to GB by night compared to the relevant 2017/18 forecast profiles. The exports from SEM to GB on Moyle have been capped in line with the firm export capacity on the interconnector. In general, the 2018/19 profiles for Moyle show a shift to higher imports during the day compared to the relevant 2017/18 forecast profiles, with the exception of at the evening peak). These changes to the interconnector flows in the 2018/19 PLEXOS model drive a higher DBC cost.

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 I-SEM to GB and flows above the x-axis represent imports from GB to I-SEM.

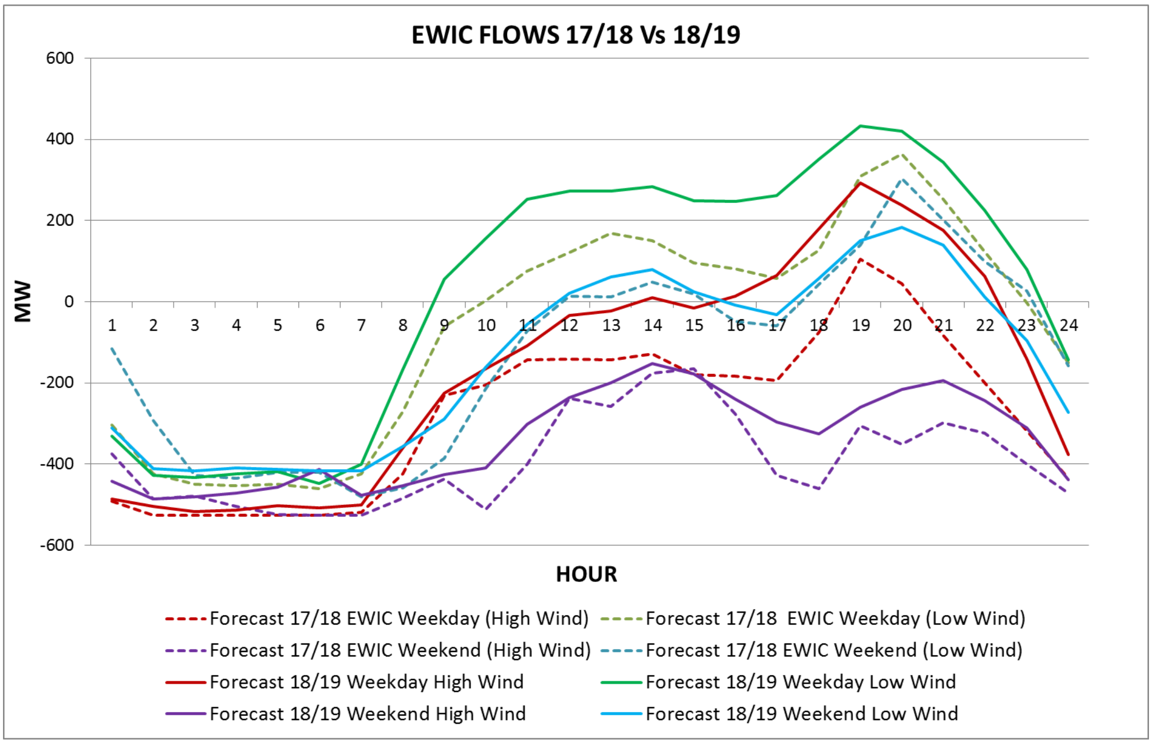

Figure 2: Market Interconnector Flows used for EWIC

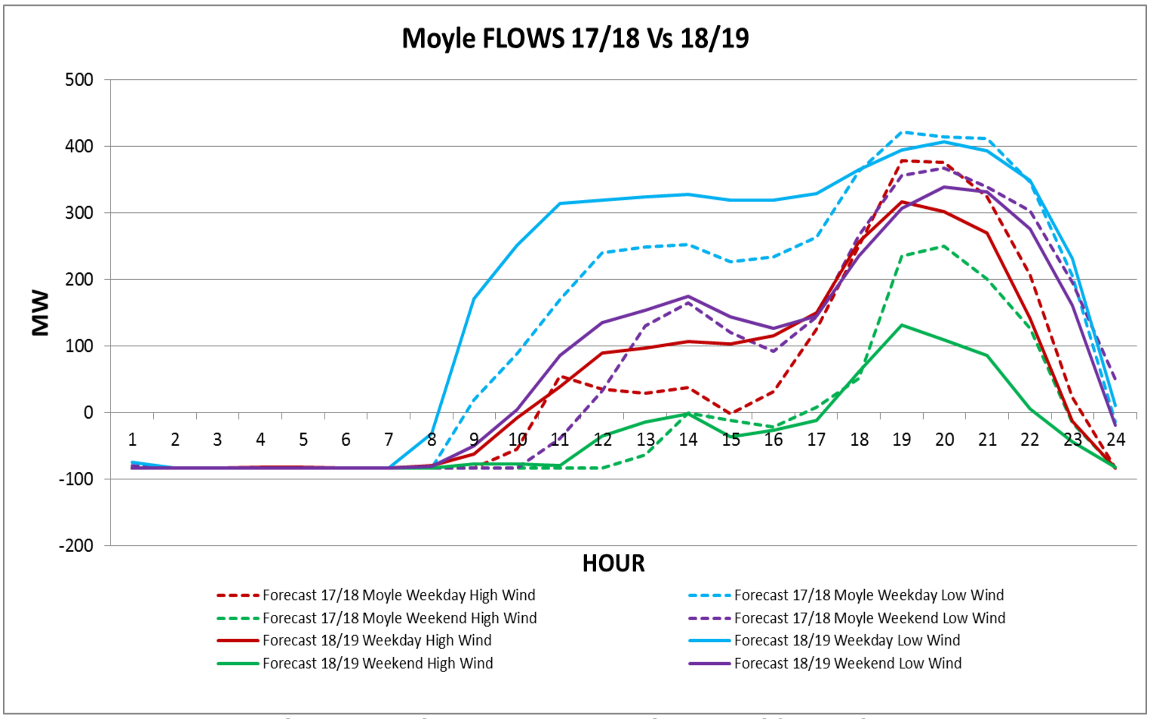

Figure 3: Market Interconnector Flows used for Moyle

1.1.4 System Operator Countertrading

System Operator (SO) interconnector countertrading arrangements in SEM allowed the TSOs, post SEM gate closure, to initiate changes to interconnector flows for reasons of system security or to facilitate priority dispatch generation, consistent with SEM-11-062[1]. This activity was carried out in accordance with parameters approved by the RAs. The TSOs also introduced the initiative of countertrading for reserve co-optimisation in March 2014 to assist in the management of DBC, following a request from the RAs in 2014[2]. Furthermore the TSOs, at times, incurred net DBC costs due to countertrading as a result of an operational export limit on EWIC in order to maintain system security.

For the 2018/19 forecast only priority dispatch countertrading has been enabled in the constrained model for EWIC and Moyle. This is because at this point in time the TSOs are not considering counter trading for reserve co-optimisation in I-SEM, in order to allow further market participant trading while the gate windows are still open. Countertrading for reserve co-optimisation reasons has the effect of reducing DBC. Also the Operational Export limit for EWIC has been removed and is therefore not applicable for 2018/19 tariff year. The net reduction to DBC from the revenue associated with the priority dispatch countertrading has been estimated in the supplementary modelling using historical prices. A provision has also been made for SO interconnector countertrading for System security, based on historical data, within the supplementary modelling section.

[1] SEM-11-062 Decision Paper
[2] http://www.eirgridgroup.com/site-files/library/EirGrid/InformationNoteExtensionofTSOcounter-tradingfacilitiesforDBCmanagement.pdf

1.1.5 Wind Curtailment in I-SEM

In I-SEM wind curtailment which has firm access will no longer retain energy revenue based on its available active power. Instead it will have to pay back the imbalance settlement price. This was accounted for in the 2018/19 forecast in the PLEXOS modelling in order to determine what impact this would have. The result was a lower difference between the constrained and unconstrained PLEXOs model production costs and thus a lower Imperfections cost.

2. Forecast Constraint Costs

This section contains the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2018/19, 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 tariff year 2018/19 is **€149.48 million**. Separate provisions which cannot be modelled in PLEXOS have been captured in the supplementary modelling described in section 2.2.2 below. This PLEXOS model portion of the forecast has increased from the forecast costs of €140.04 million for the tariff year 2017/18.

The most significant influences on forecast constraint costs in the PLEXOS model are:

- An increase in available priority dispatch generation in the unconstrained PLEXOS model contributes to an additional €17 million compared to the 2017/18 forecast
- An increase in wholesale fuel prices increases constraint costs by €8 million
- Updated modelling associated with the increased number of negatively priced DSUs and demand changes in the Dublin area increases constraints by €12 million compared to the 2017/18 forecast.
- An improvement in generator minimum generation parameters contributes to a reduction of €49 million compared to the 2017/18 forecast.
- In I-SEM firm wind generation which is curtailed down from its market position will pay back the imbalance settlement price for that volume rather than retaining market revenue, which they currently would under SEM rules. This leads to a reduction of €8.9 million in the forecast.
- The lower efficiency of Turlough Hill when operating in Minimum Stable Generation mode has now been incorporated in the PLEXOS model. Previously this was handled in supplementary modelling. Therefore this has moved the DBC provision from the supplementary modelling component to the PLEXOS modelling component for the 2018/19 forecast.

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 2018/19 is **€66.5 million**. This represents an increase of €10.17 million from the 2017/18 tariff year.
Note that the supplementary modelling for the 2017/18 forecast was split into two parts, the portion of the year covering SEM (from 01/10/2017 to 22/05/2018) and the portion

covering I-SEM (from 23/05/2018 to 30/09/2018). Certain aspects of this were only applicable to either the SEM or I-SEM portions of the year, due to the different market designs. Caution must therefore be taken in comparing the cost differentials between the supplementary modelling for 2017/18 and 2018/19 forecasts.

The largest influences on the changes to supplementary modelling are:

Imbalance Price Impact: The imbalance price in I-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. As such it is very difficult to understand what these will look like in I-SEM without any operational experience at the point in time of data freeze. The reason this is important to DBC is that the TSOs will 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 €45.54 million has been calculated within supplementary modelling for the entire 2018/19 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 proxies of a potential high imbalance price of €89.41/MWh and a potential low imbalance price of €24.54/MWh. In addition to this it was only assumed (based on modelling outcomes) that the constrained up generators from the constrained model would be paid at the high Imbalance price 33% of the time and constrained down generators would pay back at the lower Imbalance price 5% of the time. In this regard the TSOs have taken on board the feedback of the RAs i.e. that the imbalance price will not always be higher/lower than the constrained up/down generator complex offer price. However there could be periods where the Imbalance price is as high as Price Cap (circa €10,000/MWh). As such the TSOs feel the provision within this supplementary modelling is a conservative approach and would like to point out the potential risk of, in particular, higher imbalance prices.

Dispatch Down of DSUs: Currently in SEM DSUs are dispatched down from their market position instead of dispatching down priority dispatch generation in line with the SEMC decision SEM-11-062. When negatively priced DSUs are dispatched down from their market position they receive a constraint payment due to their negative offer price and the Trading and Settlement Code algebra. The volume of dispatched down DSU generation was obtained by comparing the unconstrained and constrained model outputs. The volumes were then multiplied by the offer prices used in the model (which were based on historical offer prices). The result of this gives a provision of €8.34 million for supplementary modelling. It is important to note that this analysis is based on SEM offer data in which 5 DSUs offer at SEM Price Floor of -€100/MWh. In I-SEM Price Floor will be -€1000/MWh. So in theory DSUs could offer in at this price, which would mean a far greater exposure to Imperfections. If DSUs increased their current offers proportionately with the new I-SEM Price Floor the cost to imperfections could be €83.4 million. The TSOs have taken a very conservative approach to this in that a provision of only €8.34 million is included as there is no insight of what participant bidding behaviour will be in I-SEM.

Northern Ireland Gas Product Charges: A number of Northern Ireland generators have included a gas product charge in their offers in the SEM since October 2016, the result of which has increased DBC. It is assumed that this bidding strategy will continue for the 2018/19 tariff year in I-SEM and will continue to increase DBC. The impact calculated from the 2016/17 ex-post adjustment model for the Incentive showed the impact to DBC to be €7 million. Therefore a provision of €7 million has been included in the 2018/19 forecast based on this analysis.

Capacity Testing & Performance Monitoring: There has been a large increase in both the number of DSU participants and also their available MWs. A provision has been made to allow up to four test starts on each unit if they have not already been dispatched on in the PLEXOS constrained model. Many of the high priced DSUs were not dispatched in the constrained PLEXOS model and therefore a provision for four starts during the tariff year needed to be calculated. This has increased this element of supplementary modelling.

System Operator Interconnector Trades – Priority Dispatch: For the 2017/18 forecast the supplementary modelling included a provision for priority dispatch, reserve co-optimisation and export limits. These trades were facilitated via a third party trading partner. It is the intention of the TSOs that a similar third party trading facility is set up in I-SEM, which will allow for countertrading for priority dispatch reasons as well as for system security. As such a provision is included for countertrading to reduce the curtailment of priority dispatch generation in the 2018/19 forecast supplementary modelling. This provision has been calculated based on the volume of trades as calculated by the PLEXOS model and the actual historical price of these particular types of trades.

System Operator Interconnector Trades - RoCoF: The current all-island Rate of Change of Frequency (RoCoF) limit of 0.5 Hz/s can require trading on EWIC to reduce the level of export to an acceptable level. This typically happens at times of high wind when the level of inertia on the system is reduced. As mentioned above the TSOs envisage a similar set up with a third party trading partner to allow for this type of system security trades in I-SEM. To calculate a provision for this, the actual cost of trading for this reason from 07/11/2018 (when the operational export limit on EWIC was removed) to 31/03/2018 was obtained as a proxy. The cost of these trades is typically higher than countertrading for priority dispatch therefore this figure is a best estimate. Note that there is a separate work stream under DS3 which is looking at the issues associated with increasing the all-island RoCoF limit to 1 Hz/s.

Interconnector Ramp Rate Disparity: In I-SEM an imbalance volume and cost will 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 2017/18 the TSOs recommended a provision of €10.77 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 decision as to what the interconnector ramp rate would be set to in the I-SEM reference program. Since this time further studies and discussions have taken place on the issue. An updated assessment of the exposure has been calculated as €8 million for the 2018/19 Imperfections forecast following further engagement between the TSOs and RAs.

Long Notice Adjustment Factors: For the 2017/18 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 I-SEM (SEM-17-046). A provision of zero was therefore made for the 2018/19 forecast.

2.2.2 Changes for 2018/19

A number of items were removed from supplementary modelling for 2018/19 due to the ability of participants to trade closer to real time. These were:

- Changes to demand and generation availability
- Wind predictability
- Long start up and notice times

The specific reserve constraints associated with Turlough Hill has also been removed from supplementary modelling as this has been captured in the PLEXOS model.

Furthermore the impact of non-firm wind generation being dispatched down has been removed from supplementary modelling as in I-SEM they will have to pay back their ex-ante market revenue.

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

Description	18/19 Forecast (€m)
PLEXOS Modelled Constraints for 12 Months	*149.48*
Block Loading	0.06
Capacity Testing & Performance Monitoring	3.82
System Operator Interconnector Trades - Frequency Service	0.25
System Operator Interconnector Trades - Priority Dispatch	-2.01
System Operator Interconnector Trades - System Security	2.73
Secondary Fuel Testing	0.77
Dispatch Down Cost of DSUs	8.34
Imbalance Price	45.54
Northern Ireland Gas Product Charges	7.00
Long Notice Adjustment Factors	0.00
Supplementary Modelling Total	*66.50*
Total Constraint Costs	**215.98**
Interconnector Ramp Rate Disparity	8.00
Fixed Cost Payments	7.19
TOTAL	**231.17**

2.3 Imperfections Charges – other components

In addition to the €215.98 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	**215.98**
- Constraints	**215.98**
- Uninstructed Imbalances [3]	**0.0**
- Testing Charges [4]	**0.0**
Fixed Cost Payments [5]	**7.19**
Interconnector Ramp Rate Disparity	**8.0**
Other System Charges	**0.0**
FORECAST IMPERFECTIONS REVENUE REQUIREMENT	**€231.17**

[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 2018/19 tariff year is included in this submission, based on the actual Make Whole Payments from 01/10/2017 to 31/03/2018.*

3. Risk Factors

It is important to note there are a large number of risk factors which should be considered when assessing the appropriate level of Dispatch Balancing Costs to be included in the Imperfections revenue requirement. The main 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 I-SEM Design

As mentioned already in this submission there are many unknowns in relation to the impact of I-SEM on Imperfections. This submission has attempted to capture the main potential impacts to DBC, however it is likely that other unknown risks (at the time of data freeze) have not been accounted for and will only become clear following the implementation of I-SEM.

A factor of the imbalance pricing design for I-SEM that could impact on DBC but could not be estimated at the time of submission, is the fact that the Imbalance Price is based on the average offer price of the most expensive 10 MWh required for balancing for each 5 minute Imbalance Pricing Period. These are then averaged over the 30 minute settlement period to create an Imbalance Settlement Price. This means that the Imbalance Price can be different (less marginal) than the Marginal Energy Action Price,

(The Marginal Energy Action Price can be determined as the price of the highest priced unflagged action when there is a positive net Imbalance volume or the lowest priced unflagged action when there is a negative net Imbalance volume). Bearing in mind that generators will get settled at the better of their offer price and the Imbalance Settlement Price, this will result in energy actions with offer prices between the Imbalance Settlement Price and the Marginal Energy Action Price, resulting in top up payments owed to these generators that will be paid by the TSOs through Imperfections payments. However at the time of submission of this forecast there is no experience of how big an impact this will be and no provision has been calculated.

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 2018/19 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 2018/19 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

2018/19 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

Analysis of recent interconnector trading activity reveals that flows are not purely price-based and are predominantly imports from GB to SEM during the day and exports from SEM to GB during the night. Participant behaviour could result in interconnector flows that differ greatly from those forecasts. This, in turn, could result in constraint costs changing significantly. Market interconnector flows have therefore been forecast using historical data from SEM from 01/10/2017 to 31/03/2018. The TSOs will closely monitor the forecast flows against actual market Interconnector flows in I-SEM 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 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. Firstly the cost of constraining on generators will increase and secondly 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 have included a gas product charge in their offers to the SEM, which has increased DBC. The current number of these generators has been taken 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 I-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.

[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

3.1.11 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. However, in I-SEM, simple bids and offers of generators will not be bound by the same guidelines of the BMPCOP. These simple offers and bids could set the imbalance price and therefore impact DBC, due to the fact that the TSO will have to pay 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 Modifications to the I-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 Security of Supply

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 2018/19 tariff year. The TSOs have forecast the amount of wind which they anticipate will connect during the tariff year, based on high forecast connection rate for 2018 and 2019 and the contracted wind has been adjusted on a pro rata basis. 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 2018/19 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 A Section 4.157, the Imperfections Charge Factor (**IMPFh**) is set equal to 1 for all Trading Periods up to the Cutover Time (as defined in Part C of the Trading and Settlement Code).

However, as part of the development of the new I-SEM arrangements this clause was changed such that it was not hard coded into Part B of the Trading and Settlement Code. Under Part B, RA approval is required for the Imperfections Charge Factor (**FCIMPy**).

The intent of this new wording 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 one from the period of the Cutover Time to 30 September 2019.

5. Total Revenue & Regulatory Cost Recovery

Given the extent of total DBC, which runs to €100's millions annually, the principle of costs being 100% pass through, through the k factor as per the current arrangements, is of paramount importance. Equally, the ability to fund any revenue shortfalls, and without delay, is critical for all.

For the reasons outlined in this submission, and in the context of I-SEM, both the unpredictability and volatility of DBC is expected to rise considerably. EirGrid and SONI are in advanced stages of negotiation with banks regarding the putting in place of separate contingent capital facilities, €150m for EirGrid and £45m for SONI, to cover any revenue shortfalls as may be required in making payments as Market Operator under the SEM Trading and Settlement Code, as System Operator under the Capacity Market Code and as System Operator in respect of the provision of payments under the New DS3 System Services Arrangements. For the avoidance of doubt this would cover any revenue shortfalls in relation to DBC.

Whilst it is expected that such a framework will ultimately be put in place in advance of I-SEM go live, there is a requirement from the banks to have regulatory assurance in the form of a letter of support from both the CRU and the UR. The TSOs have recently issued letters to their respective Regulatory Authorities seeking such letters of support as soon as possible, given the urgent need to have the facilities in place. Without such facilities the TSOs would not be in a position to cover any variances in the DBC forecast. This is in line with the recently approved modification to the Trading and Settlement Code (Mod_16_17) which inserted an additional section, F.22, which addresses actions to be taken in the event of working capital shortfalls.

To date, in the context of SEM and its associated risks, EirGrid and SONI have supported revenue mismatches through the provision of contingent capital facilities, standby debt supported by company balance sheet. Arrangements were in place whereby EirGrid and SONI would advise the Regulatory Authorities when adverse imbalances the equivalent of 50% of the available contingent capital had been reached and again at adverse imbalances equivalent to 75%.

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.

It should be noted, the TSOs have to date been incentivised to manage DBC (SEM-12-033) against the ex-ante forecast subject to an ex-post adjustment framework since tariff year 2012/13. It is assumed the existing framework will continue up until I-SEM go-live. The TSOs have developed a proposal paper with regards to the Incentive framework for I-SEM, which will be submitted to the RAs for consideration in the coming weeks.

Appendix 1: Overview of Imperfections and Modelling Constraint Costs

1. Overview of Imperfections

The purpose of the Imperfections Charge in I-SEM remains similar to that in SEM 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 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 further summary of the PLEXOS modelling and associated assumptions is provided in Appendix 2.

[8] 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 18/04/2018.
Forecast Period	The forecast period is from 01/10/2018 to 30/09/2019.
Currency	All costs are modelled in euro.
Fuel and Carbon Prices	Fuel prices for 2018/19 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 I-SEM in line with the current Bidding Code of Practice[11].
Demand Forecast	The demand is based on the 2018/19 median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2017-2026[12]. An adjustment was made to the demand forecast to 2018/19 to account for the fact that a certain level of embedded generation were transferring to registering as Demand Side Units (DSUs).
Generator Schedule Outages	2018 and 2019 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 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.

[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/4289_EirGrid_GenCapStatement_v9_web.pdf
[13] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdate28March_2018.pdf

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.
I-SEM	No explicit modelling provision has been made to reflect I-SEM 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
- SO Interconnector Trading
- New items in I-SEM which cannot be modelled

- Gas Transportation Capacity charging

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 2018/19 tariff year for all applicable units.

2.5.3. SO Interconnector Trades

An explicit provision is made for constraint costs arising from SO Interconnector Trades for the Low and High Frequency Service on Moyle and on EWIC, in line with previous years. This has been applied for the entire 2018/19 tariff year.

SO interconnector countertrading arrangements allow the TSOs, post gate closure, to initiate changes to interconnector flows for reasons of system security, to facilitate priority dispatch generation, as directed by SEM-11-062. The TSOs currently utilise a third party trading partner to carry out these trades.

For the 2018/19 tariff year the flows for both EWIC and Moyle were compared between the constrained and unconstrained PLEXOS models. The volumes of countertrading associated with priority dispatch were calculated based on a set of assumptions. The estimated revenue received from 09/04/2017 to 18/04/2018 was used to determine an average €/MWh for these countertrades to determine the revenue which would be received. This results in a net reduction for SO Interconnector Trades for priority dispatch in this submission.

For the 2018/19 submission a separate provision was included for trading required for Rate of Change of Frequency (RoCoF) limits. The current all-island Rate of Change of Frequency (RoCoF) limit of 0.5 Hz/s can require trading on EWIC to reduce the level of export to an acceptable level. This typically happens at times of high wind when the level of inertia on the system is reduced. A third party trading facility is to be set up in I-SEM which will allow the TSOS to countertrade for this reason to maintain system security. Note that there is a separate workstream under DS3 which is looking at the issues associated with increasing the all-island RoCoF limit to 1 Hz/s.

2.5.4. Northern Ireland Gas Product Charges

Since October 2016 a number of Northern Ireland generators have included a gas product charge in their offers to the SEM, which has increased DBC. It is assumed that this bidding strategy will continue for the 2018/19 tariff year. Due to the how these units change their offers in the within day market, it was not possible to model this in the forecast PLEXOS model. As such the additional associated forecast cost has been included in the 2018/19 forecast, based on the impact to DBC of the 2016/17 incentive model using actual historical offer data. The cost of the equivalent generators in Ireland is not included in the supplementary modelling as they are incorporated in the commercial offer data of the PLEXOS model.

2.5.5. Imbalance Price

The introduction of an imbalance price in I-SEM means that generators will be paid the better of their offer price and Imbalance price for non-energy actions taken to constrain that generator on or up and will pay back the lesser of their bid price and the imbalance price. The calculation of the imbalance price can be based on the simple offers of generators used for energy actions. These simple offers can include start cost components and are not governed by the BMPCOP. Therefore the imbalance price has the potential to be much higher than the complex offer cost of a generator that is constrained on/up for non-energy actions. This will increase Imperfections.

Also it is expected that due to the inherent differences between the Euphemia day-ahead optimisation and that of the Balancing Market software, there will be an increased volume of constraints compared to those currently occurring in SEM.

Due to the fact that this forecast uses a SEM based PLEXOS modelling approach the impact of the additional cost of paying generators at the higher Imbalance price and that there will be an increased volume of constraint a provision has been estimated using the SEM complex offer data of generators in the PLEXOS model.

2.5.6. Long Notice Adjustment Factors

The parameters associated with Long Notice Adjustment Factors have been set to zero for the first year of I-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.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-046%20I-SEM%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 2017/18 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 in I-SEM 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

In I-SEM the purpose of Fixed Cost Payments will be similar to that of Make Whole Payments in SEM in that they make up any difference between the total Energy Payments to a generator and the production cost of that generator on a weekly basis. A provision for the Fixed Cost Payments for the entire 2018/19 tariff year is included in this submission, based on the experience of actual outturn of Make Whole Payments in SEM from 01/10/2017 to 31/03/18.

8. Interconnector Ramp Rate Disparity

In I-SEM an imbalance volume and cost will 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.

Based on the I-SEM imbalance pricing design and widespread international experience it is expected that, on average, when the imbalance market is short the imbalance price will be higher than when the imbalance market is long. Interconnector imbalances will both impact and be exposed to this price differential. While there is uncertainty on future I-SEM imbalance prices, this fundamental relationship is expected to hold. As such the TSOs recommend a provision of €8 million for the Imperfections forecast revenue requirement for 2018/19 based on studies carried out and discussed with the RAs in a separate work stream.

The TSOs would like to reiterate that this is not a volatility issue that will be dealt with under the context of contingent capital and as such a provision for this I-SEM change is required as part of this submission.

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 2018/19 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 01/10/2018 to 30/09/2019
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
Regional Load	NI total load and IE total load are represented using individual

[17] https://thomsonreuterseikon.com/

Feature	Assumptions
	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 2017-2026[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: 2017/18 Validated SEM Generator Data Parameters[19]. 1. Fuel cost (€/GJ) – forecasted for 2018/19 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 2017/18 Validated SEM Generator Data Parameters[21] 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 A number of Minimum Stable Generation parameters were updated to reflect upcoming changes which are anticipated in advance of I-SEM go-live. The capping of the Maximum Generation based on the

[18] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf
[19] https://www.semcommittee.com/news-centre/baringa-sem-plexos-forecast-model-2016-17

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 2018 and 2019 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 2017/18 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 the All Island Renewable Connection Report 36 Month Forecast (Q4 2013)[21]. For the 2017/18 and 2018/19 tariff years the high all-island connection rate from the All Island Renewable Connection Report 36 Month Forecast (Q4 2013) which was 670 MW / year. Solar generation resources are based on information from the Generation Capacity Statement 2017 - 2026[22]. This indicates that there will be 126 MW of transmission connected controllable solar in Northern Ireland on 30/09/2018 which increases to 138 MW by 30/09/2019. In Ireland there is assumed to be 0 MW of transmission connected controllable solar on 30/09/2018 which increases to 50 MW by 30/09/2019.
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 52% 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,

[20] CRU/14/047 – Decision on Installed Capacity Cap
[21] http://www.eirgridgroup.com/site-files/library/EirGrid/All_Island_Renewable_Connection_Report_36_Month_Forecast__(Q4_2013).pdf
[22] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

Feature	Assumptions
	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 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. It is expected that the export capacity on Moyle will be capped at 83 MW.
Non-Synchronous Generation	System Non-Synchronous Penetration (SNSP) is set at 65% in the constrained PLEXOS model.

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 300 MW N-S and 125 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[25]
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.

[25] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdate28March_2018.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
Binbane - Letterkenny 110 kV	15/12/2018 00:00	15/01/2019 00:00
Flagford - Louth 220 kV	05/08/2019 00:00	15/08/2019 00:00
Oldstreet - Woodland 400 kV	01/08/2019 00:00	01/09/2019 00:00
Carrickmines PST	01/05/2019 00:00	01/08/2019 00:00
Great Island - Kilkenny 110kV	01/03/2019 00:00	01/04/2019 00:00
Kellis - Kilkenny 110 kV	01/06/2019 00:00	01/07/2019 00:00
Killonan - Tarbert 220 kV	01/05/2019 00:00	01/06/2019 00:00
Kilpaddoge - Tarbert 220 kV	01/03/2019 00:00	01/04/2019 00:00
Killonan - Limerick 110 kV	01/08/2019 00:00	01/09/2019 00:00
Aughinish - Kilpaddoge 110 kV	01/04/2019 00:00	01/06/2019 00:00
Moneypoint - Oldstreet 400 kV	01/09/2018 00:00	01/11/2018 00:00
Moneypoint - Prospect 220 kV	01/06/2019 00:00	01/08/2019 00:00
Moneypoint T4202	01/06/2019 00:00	01/08/2019 00:00
Great Island - Waterford #2 (TWO) 110 kV	01/09/2018 00:00	20/09/2018 00:00
Letterkenny - Trillick 110 kV	01/07/2019 00:00	20/07/2019 00:00
Drumkeen - Letterkenny 110 kV	01/06/2019 00:00	01/08/2019 00:00
Letterkenny - Tievebrack 110 kV	01/06/2019 00:00	01/08/2019 00:00
Bellacorrick - Castlebar 110 kV	09/10/2018 00:00	19/10/2018 00:00
Bellacorrick - Castlebar 110 kV	01/03/2019 00:00	07/03/2019 00:00
Bellacorrick - Moy 110 kV	12/04/2019 00:00	01/08/2019 00:00
Castlebar - Dalton 110 kV	01/09/2019 00:00	01/10/2019 00:00
Cunghill - Glenree 110 kV	01/11/2018 00:00	06/11/2018 00:00
Cunghill - Glenree 110 kV	10/03/2019 00:00	10/04/2019 00:00
Corduff - Finglas 220 kV	01/07/2019 00:00	01/08/2019 00:00
Aghada - Raffeen 220 kV	01/08/2019 00:00	01/09/2019 00:00
Aghada - Knockraha #1 (ONE) 220 kV	01/06/2019 00:00	01/07/2019 00:00
Aghada T2101	01/03/2019 00:00	01/04/2019 00:00
Killonan - Knockraha 220 kV	01/03/2019 00:00	14/04/2019 00:00
Louth - Lisdrum 110 kV	01/08/2019 00:00	01/09/2019 00:00
Moneypoint - Oldstreet 400 kV	01/03/2019 00:00	01/05/2019 00:00
Oldstreet - Woodland 400 kV	01/10/2018 00:00	01/11/2018 00:00
Iniscara - Macroom 110 kV	01/05/2019 00:00	01/06/2019 00:00
Macroom - Dunmanway 110 kV	01/05/2019 00:00	01/06/2019 00:00
Great Island - Wexford 110 kV	20/03/2019 00:00	10/07/2019 00:00
Flagford - Louth 220 kV	01/08/2019 00:00	01/09/2019 00:00
Cullenagh - Knockraha 220 kV	01/05/2019 00:00	10/05/2019 00:00

Knockraha - Raffeen 220 kV	01/04/2019 00:00	01/06/2019 00:00
Maynooth - Woodland 220 kV	01/09/2019 00:00	25/09/2019 00:00
Inchicore - Maynooth #2 (TWO) 220 kV	01/04/2019 00:00	01/06/2019 00:00
Inchicore - Maynooth #1 (ONE) 220 kV	01/04/2019 00:00	01/06/2019 00:00
Booltiagh - Ennis 110 kV	01/06/2019 00:00	01/07/2019 00:00
Ballynahulla - Knockanure 220 kV	01/03/2019 00:00	01/08/2019 00:00
Great Island - Waterford #2 (TWO) 110 kV	15/06/2019 00:00	05/07/2019 00:00
Great Island - Wexford 110 kV	01/05/2019 00:00	14/06/2019 00:00
Great Island - Wexford 110 kV	15/06/2019 00:00	05/07/2019 00:00
Great Island T2102	15/06/2019 00:00	05/07/2019 00:00

Appendix 4: N-1's

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

Loss of Aghada-Knockraha #1 (ONE) 220 kV
Loss of Aghada-Knockraha # 2 (Two) 220 kV
Loss of Arklow - Carrickmines 220 kV
Loss of Arklow - Lodgewood 220 kV
Loss of Ballynahulla - Knockanure 220 kV
Loss of Ballyvouskil - Clashavoon 220 kV
Loss of Ballyvouskill - Ballynahulla 220 kV
Loss of Cashla - Flagford 220 kV
Loss of Cashla - Prospect 220 kV
Loss of Cashla - Tynagh 220 kV
Loss of Clashavoon – Knockraha 220 kV
Loss of Clonee – Corduff 220 kV
Loss of Clonee – Woodland 220 kV
Loss of Corduff – Finglas #1 (ONE) 220 kV
Loss of Corduff – Woodland 220 kV
Loss of Cullenagh - Great Island 220 kV
Loss of Cullenagh - Knockraha 220 kV
Loss of Dunstown – Kellis 220 kV
Loss of Dunstown - Maynooth 220 kV
Loss of Flagford - Louth 220 kV
Loss of Flagford - Srananagh 220 kV
Loss of Great Island - Kellis 220 kV
Loss of Glanagow – Raffeen 220 kV
Loss of Gorman - Louth 220 kV
Loss of Gorman - Maynooth 220 kV
Loss of Great Island – Lodgewood 220 kV
Loss of Killonan – Knockraha 220 kV
Loss of Killonan – Shannonbridge 220 kV
Loss of Killonan – Tarbert 220 kV
Loss of Kilpaddoge - Knockanure 220 kV
Loss of Kilpaddoge - Moneypoint 220 kV
Loss of Kilpaddoge - Tarbert #1 (ONE) 220 kV
Loss of Kilpaddoge - Tarbert #2 (TWO) 220 kV
Loss of Knockanure - Tarbert 220 kV
Loss of Knockraha - Raffeen 220 kV

Loss of Louth - Woodland 220 kV
Loss of Maynooth - Shannonbridge 220 kV
Loss of Maynooth - Woodland 220 kV
Loss of Moneypoint - Prospect 220 kV
Loss of North Wall – Poolbeg 220 kV
Loss of Oldstreet – Tynagh 220 kV
Loss of Prospect - Tarbert 220 kV
Loss of Ardnacrusha – Singland 110 kV
Loss of Ardna - Limerick 110 kV
Loss of Arigna Tee-Carrick-on-Shannon 110 kV
Loss of Ballydine – Cullenagh 110 kV
Loss of Bandon – Dunmanway 110 kV
Loss of Bandon – Raffeen 110 kV
Loss of Bellacorick - Castlebar 110 kV
Loss of Binbane – Cathaleens Falls 110 kV
Loss of Carrick on Shannon – Arigna T 110 kV
Loss of Cahir - Doon 110 kV
Loss of Cashla – Cloon 110 kV
Loss of Cashla – Dalton 110 kV
Loss of Castlebar – Cloon 110 kV
Loss of Cauteen – Killonan 110 kV
Loss of Cathaleens Falls - Clogher 110kV
Loss of Cathaleens Falls – Corraclassy 110 kV
Loss of Cathaleens Falls - Srananagh #1 (ONE) 110kV
Loss of Clogher - Golagh Tee 110 kV
Loss of Clonkeen – Knockeragh 110 kV
Loss of Clonkeen – Clashavoon 110 kV
Loss of Corderry – Srananagh 110 kV
Loss of Corduff - Ryebrook 110 kV
Loss of Corraclassy - Gortawee 110kV
Loss of Cullenagh - Waterford 110 kV
Loss of Cunghill – Sligo 110 kV
Loss of Cushaling - Portlaoise 110 kV
Loss of Dungarvan – Woodhouse 110 kV
Loss of Flagford - Sligo 110 kV
Loss of Gorman – Navan #3 (THREE) 110 kV
Loss of Kilbarry – Knockraha #1 (ONE) 110 kV
Loss of Kilbarry – Mallow 110 kV
Loss of Kill Hill – Thurles 110 kV

Loss of Killonan – Singland 110 kV
Loss of Kilpaddoge – Tralee #2 (TWO) 110 kV
Loss of Knockraha – Barrymore T 110 kV
Loss of Knockraha – Woodhouse 110 kV
Loss of Marina Trabeg #1 (ONE) 110 kV
Loss of Marina Trabeg #2 (TWO) 110 kV
Loss of Raffeen - Trabeg #1 (ONE) 110 kV
Loss of Raffeen - Trabeg #2 (TWO) 110 kV
Loss of Shannonbridge – Dalton T 110 kV
Loss of Shannonbridge – Ikerrin T 110 kV
Loss of Shannonbridge – Somerset T 110 kV
Loss of Sligo - Srananagh #1 (ONE) 110 kV
Loss of Tarbert - Trien 110 kV
Loss of Clashavoon trafo
Loss of Great Island T2101 trafo
Loss of Great Island T2102 trafo
Loss of Moneypoint - Dunstown 400 kV
Loss of Moneypoint - Oldstreet 400 kV
Loss of Oldstreet - Woodland 400 kV
Loss of Castlereagh - Kilroot 275 kV
Loss of Kilroot - Tandragee 275 kV
Loss of Coleraine - Coolkeeragh 110 kV
Loss of Coleraine - Limavady 110 kV
Loss of Coolkeeragh - Killymallaght 110 kV
Loss of Dungannon - Omagh 110 kV
Loss of Dungannon to Tamnamore 110 kV
Loss of Kells to Rasharkin 110 kV
Loss of Omagh to Strabane 110 kV

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
I-SEM	Integrated Single Electricity Market
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