Forecast Imperfections Revenue Requirement

Tariff Year 2022/23

V2.0

V1.0: issued to RAs 31/05/2022
V2.0: issued to RAs 29/06/2022: updated to include Appendix 7: Additional RA Request

Executive Summary

This submission represents the Transmission System Operators' (TSOs') forecast of the revenue requirement[1] to be recovered through Imperfections Charges during the 2022/23 tariff year.

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

The forecast revenue requirement, based on a number of assumptions and expected conditions for the 2022/23 tariff year period (01/10/2022 to 30/09/2023), is €730.45m. This is an increase of €257.36m over the equivalent forecast 2021/22 requirement of €473.09m, of which €341.01m was approved, by the Regulatory Authorities, in their final decision on the Imperfection Charge.

The approach taken in the 2022/23 forecast has been to use a PLEXOS model, which assumes that the Dispatch Balancing costs in SEM are based on the production cost difference between the unconstrained and constrained models. Additional SEM costs, not covered in the PLEXOS model, are captured in supplementary modelling.

The main components of the 2022/23 forecast revenue requirement submission are set out in the table below:

Component	22/23 Forecast (€m)	21/22 Forecast (€m)
PLEXOS Model	532.94	291.40
Supplementary Model	197.51	181.69
Total 2022/23 Forecast Imperfections Revenue Requirement	730.45	473.09

[1] This paper set out the revenue requirement for 2022/2023 and excludes the K-factor which will be separately submitted. The total revenues to be recovered under the Imperfections Charge are the sum of the revenue requirement and the k factor.

1. Introduction

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

The submission reflects the TSOs' forecast of the revenue required from the Imperfections Charge for the 12-month period from 01/10/2022 to 30/09/2023 inclusive, referred to as the tariff year 2022/23.

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

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

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 in Ireland and SSS tariff Northern Ireland, under the respective regulatory arrangements pertaining.

The TSOs' forecast for the Imperfections revenue requirement is €730.45m, in nominal terms, for the tariff year 2022/23. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Background of the SEM

The wholesale electricity market arrangements for Ireland and Northern Ireland were revised under the I-SEM Project, with the revised SEM arrangements going live on 01 October 2018. These 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 several markets including:

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

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

However, on 01 January 2021, GB decoupled with the EU Internal Energy Market (IEM) as a result of Brexit. As SEM has no direct interconnection to the IEM it was also forced to decouple the DAM auction resulting in local auctions only for SEM and GB. Intraday markets are traded at regional level between SEM and GB and not at EU level therefore the interconnector capacity could continue to be utilised in the coupled IDA1 and IDA2 auctions through which interconnector flows are implicitly allocated.

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

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

1.2 Modelling approach for Tariff Year 2022/23

The approach taken in the 2022/23 forecast has been to use a PLEXOS model, which assumes that the Dispatch Balancing costs in SEM are based on the production cost difference between the unconstrained and constrained models. Given the significant increase in forecast Imperfections Costs for 2022/23, the TSOs engaged an external consultant to review our PLEXOS model. The approach and findings of the consultant are detailed in their report (see Appendix 8). As a result of the review, the consultant made several recommendations to improve the representation of the model, which the TSOs have incorporated. These recommendations are detailed in Appendix 8.

Revised SEM arrangements since Oct 2018 have seen an increase in Imperfections Costs. In the current settlement design the imbalance price is one of the major drivers of constraint costs. The imbalance price can be volatile compared to the legacy SEM, with multiple instances of the price being negative when the market is long and the price being very high at times when the market is short and highly constrained. Because the production cost difference between the unconstrained and constrained model does not consider the model price, additional post processing shadow settlement was conducted outside of the PLEXOS model. The two scenarios which cannot be captured in PLEXOS production cost difference are when the constrained-up price is lower than the imbalance price and when the constrained down price is higher than the imbalance price. Another feature of the revised SEM arrangements, which could not be fully captured in PLEXOS, is that generators can submit both complex and simple commercial offer data, in the form of complex incremental/decremental costs, and simple incremental/decremental costs. Additional costs that cannot be modelled are captured in the supplementary modelling.

2. Forecast Constraint Costs

This section sets out the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2022/23, 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 are outlined in Section 2.3.

2.1 PLEXOS Results

The forecast cost of the constraints modelled using the PLEXOS model for the 2022/23 tariff year is €532.94m. For reference the PLEXOS cost for 2021/22 was €291.40m. The TSOs have undertaken a "Take Out One at a Time" analysis to determine the approximate scale of each single input change in reference to the final model. This involved starting with the final 2022/23 Forecast model and then taking out one input at a time and replacing it with what was in the previous 2021/22 Forecast, the results of which are shown in Figure 1 below.

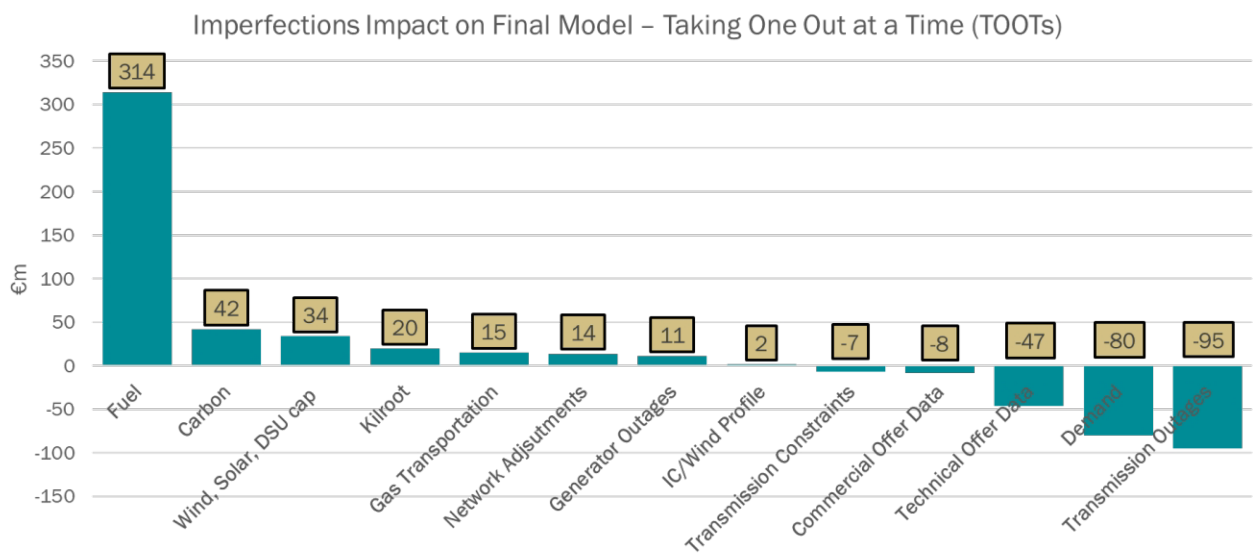

Figure 1: Taking Out One at a Time (TOOT) Analysis on 22/23 Forecast Model

The most significant influences on forecast constraint costs, compared to that forecast in 2021/22, in the PLEXOS model are:

- Fuel forecasts, which are significantly higher than those of 2021/22, have increased costs by €314m
- Carbon forecasts, which are significantly higher than those of 2021/22, have increased costs by €42m
- An increase in wind/ PV generation and DSUs contributes to an additional Imperfections cost of €34m
- Inclusion of emissions restrictions for certain units has increased model by €20m
- Update of Gas Transportation Capacity (GTC) charges has increased the PLEXOS model by €15m
- Update of model adjustments has increased the cost by €14m
- Forecast generator outages for 2022/23 has increased costs by €11m

- Revised interconnector flows and wind profiles have increased model costs by €2m
- Operational Constraint updates have decreased the model costs by €7m
- Update of generator Commercial Offer Data has reduced costs by €8m
- Update of generator Technical Offer Data has reduced costs by €47m
- Forecast demand increase has decreased the PLEXOS model constraint costs by €80m
- A significant decrease in the scale of scheduled transmission outages has decreased the PLEXOS model by €95m

There are several factors which may influence the forecast costs, and hence the Imperfections revenue requirement, for the tariff year 2022/23. Influencing factors are described in the following sections.

2.1.1 Fuel Prices/Carbon

Wholesale fuel and carbon prices are a fundamental driver of imperfections costs. Wholesale fuel prices in the last 12 months have been characterised by extreme market volatility, record high prices as well as average prices being significantly higher than previous periods.

Figure 2 outlines the differences in the fuel prices between the 2021/22 forecast and the 2022/23 forecast. These forecast costs have increased significantly. This makes the cost of constraining on out of merit generation more expensive and drives a higher production cost in the constrained model. The result is that the disparity between the unconstrained and constrained model production costs increases, and with it, the DBC.

In addition, Figure 3, shows how forecast fuel prices up until the 2021/22 Forecast were broadly similar, and how the wholesale fuel prices forecast for 2022/23 are significantly greater than those used in previous forecast models.

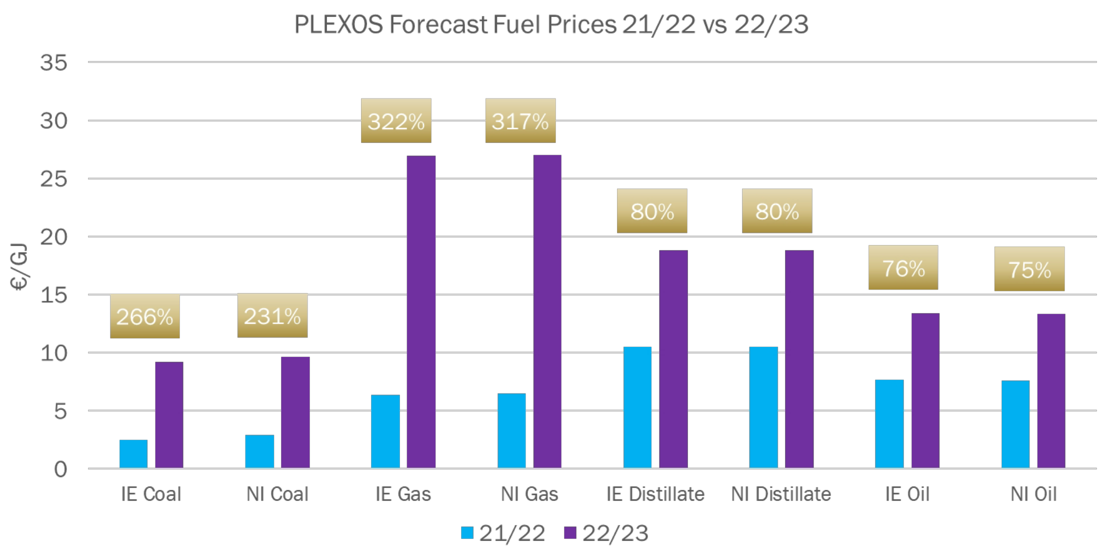

Figure 2: Forecast Model Fuel Cost Changes from 2021/22 to 2022/23

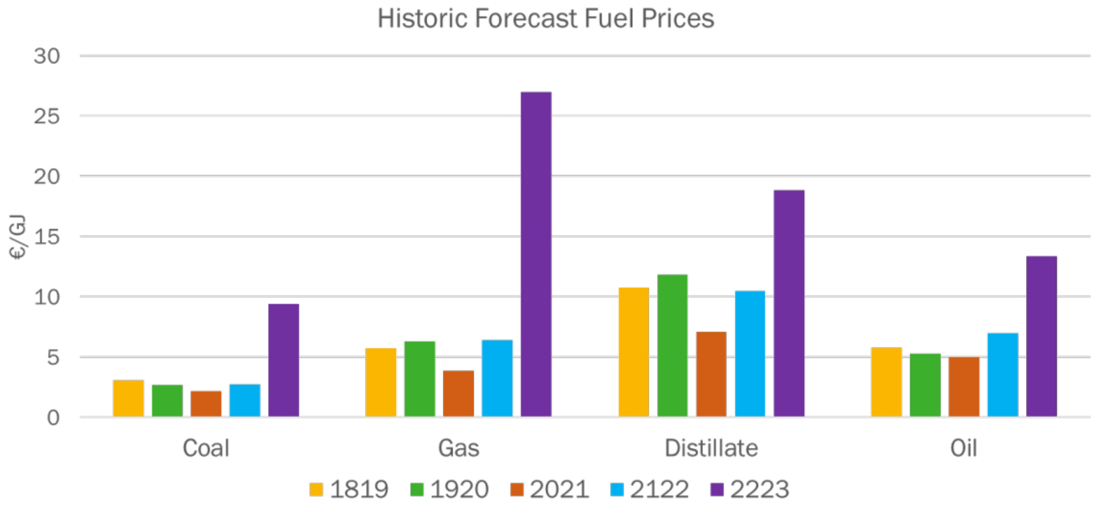

Figure 3: Forecast Model Fuel Cost Changes from 2018/19 to 2022/23

As shown in Figure 4, carbon costs have also significantly increased. Similar, to wholesale fuel prices, this results in a greater difference between the constrained and unconstrained model production costs and therefore increases DBC.

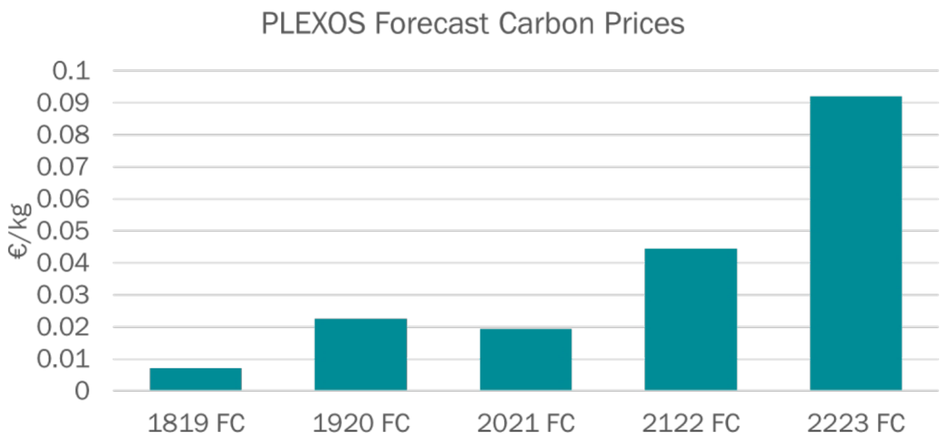

Figure 4: Forecast (FC) Model Carbon Cost Changes from 2021/22 to 2022/23

2.1.2 Wind / PV generation and DSUs

Compared to the tariff year 2021/22 forecast, there has been a change in the generation mix available in the market for 2022/23. There is an increase in priority dispatch generation from wind, solar and DSUs. This has the effect of increasing DBC, as the unconstrained model uses this as much as possible, pushing more expensive conventional generation out of the merit order. The constrained model still needs to run specific generators that may have become out of merit, due to the increase in priority dispatch generation.

2.1.3 Generator Emissions Restrictions

Certain generators have limitations on their running capabilities based on emission regulations as per their environmental permits, the scale of which is dependent on the available fuel mixes. This impact has been accounted for in the PLEXOS model, based on the latest most optimistic conditions. This reduction in the overall availability of generation leads to an increase in DBC, as relatively more expensive generation is required instead.

2.1.4 GTCs

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

2.1.5 Transmission Network Updates

The transmission network has been updated to reflect the forecast configuration. Also, station sectionalising has been updated to reflect the most common mode of operation. The most recent approved TLAFs have also be included in the model.

2.1.6 Forecast generator outages

Both scheduled and forced generator outages are considered in the PLEXOS model. Generator scheduled outages are based on the latest available information at time of data freeze.
Forced outages are modelled with a Generator Forced Outage Probability factor and a Mean Time to Repair, which are both based on analysis of historic data. Following an external review of the model (see Appendix 8), forced outage assumptions were adjusted to avoid giving large incidents undue weight. On average, the forced outage rates used in the forecast models, have been increasing year on year.

2.1.7 Revised interconnector flows and wind profiles

Forecast interconnector flows for 2022/23 are based on historic interconnector flows, matched with historic actual wind availabilities. As interconnector and wind profiles are so closely linked, the approach of using these two 'already matched' sets assists in modelling reality.
For the 2022/23 Forecast, ex-ante interconnector flows rather than Balancing Market flows were used in the Unconstrained model following recommendations from an external review of model (see Appendix 8),

2.1.8 Operational Constraints

The best estimate of operational policies / Transmission Constraint Groups (TCGs) that will be in effect for the tariff year has been considered in the model, as summarised in Table 1 below. The net effect of the update of these operational constraints has been to reduce imperfection costs.

Operational Pathway	Treatment in 22-23 Forecast Model
SNSP	Remaining at 75%
Inertia	Remaining at 23,000MWs
All-island Min Set Requirement	Remaining at 8 units (5 IE, 3 NI)
IE Dynamic Reserve	Storage has reduced this to 75MW at all times

Table 1: Summary of Operational Policies included in 2022/23 Forecast

2.1.9 Generator Commercial Offer Updates and Technical Offer Updates

Commercial Offer data such as no-load costs and start-up costs were updated based on analysis of historic data.
Technical parameters of generators, such as minimum stable level, and maximum capacities were updated. These updates were based on recent technical offer data submissions and availability declarations.
In addition, a de-rating of certain gas units in the unconstrained model was applied. The purpose of this was to better reflect their day ahead bids. This derating was one of the recommendations from an external review of model (see Appendix 8), which the TSOs incorporated in 2022/23 Forecast.

2.1.10 Demand updates

The demand in the 2022/23 Forecast is higher than that in the 2021/22 Forecast. This increased demand has reduced imperfections costs. There is a direct relationship between increasing demand in an unconstrained model and increasing model costs. In a constrained model, generators are run sub-optimally to ensure all constraints are met, and when demand is increased, effectively the model becomes more optimal. This means that typically with a demand increase, the constrained model does not increase costs as much as the unconstrained model, therefore reducing DBC.

2.1.11 Transmission Outages

The outage requirements for 2022/23 are based on the best available information, as of April 2022. The programme of outages assumed for 2022/23 is significantly less onerous than that assumed for the 2021/22 forecast. These outages are listed in Appendix 3 of this submission paper.

For Ireland, no transmission outages that constrain thermal generation, outside of scheduled generator outages, are assumed due to tight generation capacity margins.
For Northern Ireland, only two outages are assumed for 2022/23 Forecast.

2.2 Supplementary Modelling Results

The forecast cost of the constraints modelled by the supplementary modelling for the tariff year 2022/23 is €197.51m. This represents an increase of €15.82m from the 2021/22 tariff year.

The largest influences on the changes to supplementary modelling are:

Clean Energy Package: For the 2022/23 Forecast, no provision for Clean Energy Package has been included as per SEM-22-009 Decision, which states "*in the context of the current and expected next two years' high prices, the SEM Committee has decided to implement and compensate any payments for curtailment associated with this Decision, beginning in tariff year 2024/25.*" No provision for Clean Energy Package in 2022/23 has been requested, as it is assumed that no monies for Clean Energy Package will be paid out in 2022/23.

Additional CPREMIUM and CDISCOUNT Payments and Imbalance Price Impact: The imbalance price under the revised SEM arrangements is, at a high level, determined by the incremental and decremental costs of generators used for energy actions in the balancing market. TSOs pay generators the greater of their offer price and imbalance price, for increments, and the lesser of their offer price and imbalance price, for decrements, for non-energy actions taken. The majority of this extra cost is taken into account using the production cost based PLEXOS modelling, however an additional provision of €99.23m has been calculated, within supplementary modelling, for the entire 2022/23 tariff year, to capture the costs not included within the PLEXOS model. This calculation is based on actual imbalance prices, from the last 12 months.

This impact was calculated by applying the settlement calculation for the two highest settlement cost components CPREMIUMS and CDISCOUNTS. The calculation involved applying the CPREMIUM and CDISCOUNT market formulae to the dispatch volume change between the unconstrained and constrained models. A further calculation was run to account for simple price offers, based on the proportion of time generators had been settled on these, in the last 12 months.
The main driver for the increase in this component compared to the 2021/22 Forecast, is the significant increase in the imbalance price.

Dispatch of Pump Storage Units: Pump storage units are mostly dispatched in pump mode overnight, to facilitate more priority dispatch generation on the system and minimise levels of curtailment. During the day, the units are often kept at their Minimum Generation levels, to provide positive reserve. This running profile is different than the profile that clears, in the Day-Ahead market and subsequently differs from their Physical Notifications (PNs), in the Balancing Market. Thus, there are high CPREMIUMS and CDISCOUNTS paid by the TSOs to pump storage units. Another considerable difference is the offer prices associated with pump storage units in the old market, compared to the revised market arrangements. Pump storage units in the old market were bidding in with a price of 0 €/MWh and were not paid for non-energy actions, whilst under the revised market arrangements their bid offers are considerably higher. PLEXOS cannot capture the pump storage unit offer prices, thus a provision of €35.17m is included in the supplementary modelling. The provision is based on the actual CPREMIUM and CDISCOUNT payments the pump storage units received in the last 12 months.

Constrained Wind: Wind is currently not paid for curtailment in SEM; however, it is paid for constraints. Because the wind in the PLEXOS model has a price of 0 €/MWh, the provision of €23.58m is included within supplementary modelling. This figure is based on the actual CDISCOUNTS wind participants received in the last 12 months up to 20/03/2021.

System Operator Interconnector Countertrading: For the 2022/23 forecast, an allowance of €35.79m for countertrading has been requested. This allowance has been based on the experience of the last 12 months where there has been an increase in the frequency and cost of counter trades. It is anticipated that countertrading will be at least at a similar level in the upcoming 2022/23 year, due to tighter generation capacity margins, high forced outage rates and increasing demand.

Block Loading: The Unconstrained Unit Commitment (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 in the unconstrained market schedule, resulting in out-of-merit running and hence constraint costs. A small provision of €1.18m 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 and therefore no allowance for them has been included in the 2022/23 submission.

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.

There will be instances of out-of-merit generators not being required to run, and 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.

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.

Secondary Fuel 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 switch over tests for a period of time.

2.2.2 Inclusion of supplementary costs for 2022/23

The results of model costs and supplementary costs for 2022/23 are summarised in the table below:

Description	2022/23 Forecast (€m)
PLEXOS Model	532.94
Additional PREMIUM and DISCOUNT impact	99.23
Interconnector Counter Trades	35.79
Pump Storage Running	35.17
Constrained Wind	23.58
Secondary Fuel Testing	1.75
Block Loading	1.18
Capacity Testing	0.81
Clean Energy Package	0.00
Supplementary Modeling Total	197.51
Total	730.45

3. Risk Factors

Several risk factors should be considered when assessing the Imperfections Revenue requirement for 2022/23. The factors are set out below, with brief descriptions of the nature of these risks and potential mitigation measures. These factors could individually, or collectively, result in a significant deviation between the forecast and actual constraint costs.

3.1 Specific Risks

3.1.1 Wholesale Fuel Prices/ Generator Bids

Wholesale fuel prices are a key input to the forecast. The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long-term fuel prices as of May 2022.
Recent prices have been characterised by extreme market volatility: record high prices, as well as average prices being significantly higher than previous periods. An increase in fuel prices would lead to higher generator running costs and hence higher Dispatch Balancing Costs. Other factors such as changes in the cost of carbon, generator Variable Operation and Maintenance (VOM) costs or gas network capacity products, could also have a significant impact.

3.1.2 Reduced 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 (and/or expensive interconnector countertrades) may be required to provide reserve and/or system support, in areas with transmission constraints. Significant deviation from indicative generator scheduled outages and return to service dates could also lead to large variances in DBC.

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

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

3.1.4 Delays and Overruns of Outages

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

3.1.5 Network Reinforcements and Additions

The PLEXOS model was built using the most up to date data available at the time of the data freeze. The commissioning dates of projects may change in the future and any delays or advancements of dates, will have an impact on how the system can be operated. Examples of this include, but are not limited to: delays to network reinforcements, delays to new generator(s) 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 only be fully realised at this stage.

3.1.6 Interconnector Flows and System Operator Countertrading

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

It is possible that the provision we have requested for System Operator Countertrading may be a low estimate, as a result of reduced generation plant availability and increasing demand, resulting in tighter generation capacity margins.

3.1.7 High Impact, Low Probability Events (HILPs)

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

PLEXOS does include planned generator outages in the model, as 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. However, there remains the possibility of HILP(s) arising, giving rise to significant additional DBC costs, that cannot be mitigated by the TSOs; no provision for HILPs has been included in this submission.

3.1.8 Outturn Availability

A change in practice in relation to the treatment of outturn availability of generators during transmission outages[2] 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

[2] 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

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

3.1.11 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). There is no provision for any future changes to testing procedures or T&SC modifications that may result in increased costs.

3.1.12 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.

3.1.13 Additional Security Constraints

This forecast has been prepared using the best estimate of operational policies that will be in effect for the tariff year. As the system develops, these policies may no longer be required or, and additional security constraints may be required, resulting in a change in constraint costs.

3.1.14 Long Notice Adjustment Factors

As per SEM-21-68, the Long Notice Adjustment Factor (LNAF) has been set zero until 31/12/2022. A provision of zero was therefore made for the 2022/23 forecast.

3.1.15 Fixed Cost Payments

Fixed Cost Payments (CFC) in the new market comprise of: Make Whole Payment, Recoverable Start Up Costs and Recoverable No Load Costs. A provision for Fixed Cost Payments has not been sought for 2022/23. For 2022/23, from the results of the PLEXOS model, it has been assumed that the majority of these costs have been captured in the PLEXOS model and therefore a separate supplementary component has not been sought. The TSOs will consider these costs in future years and a provision may be required in the future, based on future PLEXOS results.

3.1.16 Interconnector Ramp Rate Disparity

Under the revised SEM arrangements an imbalance volume and cost arise as a result of differences in interconnector ramp rates in Euphemia (day ahead pricing algorithm currently in use throughout Europe) and real time operations. In general, the higher the ramp rate in Euphemia the higher the imbalance volume and cost. For 2022/23 the TSOs have not sought a provision for this cost, as recent historical data shows the cost to be relatively small. The TSOs will continue to monitor these costs, as a provision may be required in the future, based on further market experience.

4. Imperfections Charge Factor

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

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

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

As such, and in accordance with Section F.12.1.1 (b), EirGrid and SONI are now seeking the approval for the Imperfections Charge Factor to be set to 1 for the period of 1 October 2022 to 30 September 2023.

5. Total Revenue & Regulatory Cost Recovery

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

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

Appendix 1: Overview of Imperfections and Modelling Constraint Costs

1. Overview of Imperfections

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

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

2. Constraint Costs

2.1 Overview of Constraint Costs

Constraint costs are the largest portion of the DBC. The TSOs, in ensuring continuity of supply and the security of the system in real time, have to dispatch some generators differently from the output levels indicated by the ex-post market unconstrained schedule. Generators receive constraint payments to keep them financially neutral for the difference between the market schedule and the actual dispatch.

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

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.
- Wind, Solar and Load forecasting, which involves continually working with vendors to improve forecast accuracy.
- Development of system services will provide a system benefit.

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 market, such as Commercial and Technical Offer data, historical dispatch quantities, market schedule quantities and constraint payments, has been used to review key assumptions.

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

2.4.2 Key Modelling Assumptions

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

- Where reference is made to the Trading and Settlement Code (T&SC), the version referred to is Part B dated 9 November 2021.
- 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.

Appendix 2 lists the key assumptions used in the production of the constraints in PLEXOS for the TSOs' Imperfections revenue requirements forecast.

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.

Appendix 2: PLEXOS Modelling Assumptions

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

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 2022/23 are defined in €/GJ based on the long-term fuel forecasts from Thomson-Reuters Eikon[3] and the US Energy Information Administration. 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 01/10/2022 to 30/09/2023
Data Freeze	Majority of input data for the PLEXOS model was frozen at the end of March 2022
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.

Demand

Feature	Assumptions
Load	The demand is based on the median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2022-2031. NI total load and IE total load are represented using individual hourly load profiles for each jurisdiction.

[3] https://thomsonreuterseikon.com/

Feature	Assumptions
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	Generation resources are based on the All-island Generation Capacity Statement 2022-2031.
Fuel and Carbon Prices	Fuel prices for 2022/23 are based on the long-term fuel forecasts from Thomson-Reuters Eikon[4], the US Energy Information Administration[5]. 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.
Production Costs	Calculated through PLEXOS. The inputs to PLEXOS were based on analysis of actual bids. 1. Fuel cost (€/GJ) – forecasted for 2022/23 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.
Generation Constraints (TOD)	Based on the data in the PLEXOS Public Model for 2021-29 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
Generator Scheduled Outages	2022 and 2023 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.
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 analysis on historic outage data.
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 and solar generation resources are based on MW currently installed plus an anticipated rate of connection as per the All-Island Generation Capacity Statement 2022-2031.

[4] https://thomsonreuterseikon.com/
[5] https://www.eia.gov/

Feature	Assumptions
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 54% in the constrained model.
Security Constraints	Since a DC linear load flow is used, voltage effects and dynamic and transient stability effects will not be captured. System-wide and local area constraints have been included in the model as a proxy for these issues.
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.
Multi-Fuel Modelling	Only one fuel is modelled for each generating unit. The coal units at Kilroot, while able to run on oil, almost never do so, and will be modelled as coal only. Note that where units are multi fuel start this is modelled explicitly using one fuel offtake for each fuel. Multi fuel start units are Kilroot units one and two, Moneypoint units one, two and three and Tarbert units one, two, three and four.
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast based on actual flows derived 2020/21 historic flows.
DS3/Operational Pathways to 2030 milestones	System Non-Synchronous Penetration (SNSP) is set at 75% in the constrained PLEXOS model from Oct 2022. During the year, it is assumed that the minimum number of sets remains at 8 sets and that the minimum level of inertia is 23GWs.

Transmission

Feature	Assumptions
Transmission Data	The transmission system input to the model is based on data held by the TSOs.
N-1 Contingency Analysis	Principal N-1 contingencies, based on TSO operational experience, are modelled.
Transmission Constraints	Transmission constraints are 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.
Louth-Tandragee Tie-Line Transmission Limits	The North-South tie-line is not restricted in the unconstrained SEM-GB model. The Net Transfer Capacity (NTC) is modelled for the constrained schedule, which is assumed to be 400 MW N-S and 250 MW S-N.
Interconnection	The Moyle Interconnector and EWIC are modelled.
Forced Outages	No forced outages are modelled on the transmission network.
Transmission Scheduled and Forced Outages	The outage requirements for the 2022/23 are based on the best available information, as of April 2022. The outages assumed in the forecast are indicative only and subject to change. Forced transmission outages are not modelled.

Ancillary Services

Feature	Assumptions
Operating Reserve	Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled.
Reserve Characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.
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
Other Reserve Sources	For this forecast that DSUs, interconnectors and batteries will also provide reserve in the model.

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. The outage requirements for the 2022/23 are based on the best available information, as of April 2022. The outages assumed in the forecast are indicative only and subject to change.

Circuit/Plant	Date From	Date To
Ballylumford Eden ckt 1	01/04/2023	30/09/2023
Ballylumford Eden ckt 2	01/04/2023	30/09/2023
Omagh to Dromore 110 ckt 1	01/05/2023	30/06/2023

Appendix 4: N-1s

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

Loss of Aghada Glanagow 220	Loss of Derryiron Kinnegad
Loss of Aghada-Knockraha 1	Loss of Derryiron Thornsberry
Loss of Aghada-Knockraha 2	Loss of Derryiron to Maynooth
Loss of Aghada-Raffeen 1	Loss of Drumkeen Letterkenny
Loss of Arklow Carrickmines 220	Loss of Drumline Ennis
Loss of Arklow Lodgewood	Loss of Drybridge Gorman
Loss of Ballynahulla Knockanure	Loss of Drybridge Louth
Loss of Ballyvouskil Ballynahulla	Loss of Drybridge Platin
Loss of Ballyvouskil Clashavoon	Loss of Dungarvan-Woodhouse
Loss of Cashla Flagford	Loss of Dunmanway Macroom
Loss of Cashla Prospect	Loss of Flagford-Sliabh Bawn
Loss of Cashla Tynagh 220kV	Loss of Flagford-Sligo
Loss of CKM-Dunstown 220kV	Loss of Galway Salthill
Loss of CKM-Irishtown 220kV	Loss of Gorman - Meath Hill
Loss of CKM-Poolbeg 220 and PST	Loss of Gorman-Platin
Loss of Carrickmines - Poolbeg_220_1	Loss of Gorman-Navan 3
Loss of Clashavoon Knockraha 220	loss of Great Island - Kilkenny
Loss of Clonee Corduff 220	loss of Great Island - Wexford
Loss of Clonee Woodland 220	loss of Great Island - Waterford 1
Loss of Corduff - Finglas 220 2	Loss of Iniscara Macroom
Loss of Corduff Finglas 220 1	Loss of Kellis Kilkenny
Loss of Corduff Woodland 220 1	Loss of Kilbarry Knockraha 1
Loss of Cullenagh-Great Island 220	Loss of Kilbarry Mallow
Loss of Cullenagh-Knockraha 220	Loss of kilbarry marina 2
Loss of Dunstown - Maynooth_220_2	Loss of Kill Hill – Thurles
Loss of Dunstown-Kellis 220	Loss of Killonan-Limerick 1
Loss of Dunstown-Maynooth 220 1	Loss of Killonan-Limerick 2
Loss of Dunstown-Turlough Hill 220	Loss of Killonan-Singland
Loss of Finglas to Shellybanks 220	Loss of Kilpaddoge - Tralee ckt 2
Loss of Finglas - Belcamp_220_1	Loss of Kilpaddoge Knockanure 1
Loss of Finglas North Wall 220	Loss of Kilpaddoge Rathkeale
Loss of Flagford-Louth 220	Loss of Kilteel Maynooth
Loss of Flagford-Srananagh 220	Loss of Kilteel Monread
Loss of Glanagow Raffeen 220	Loss of Kinnegad to Mullingar
Loss of Gorman-Louth 220	Loss of Kinnegad Dunfirth T
Loss of Gorman-Maynooth 220	Loss of Knockraha - Barrymore T
Loss of Great Island - Kellis 220	Loss of Knockraha Woodhouse
Loss of Great Island - Lodgewood 220	Loss of Lanesboro Mullingar
Loss of Inchicore - Maynooth_220_1	Loss of Lanesboro-Sliabh Bawn
Loss of Inchicore - Poolbeg_220_1	Loss of Letterkenny Golagh T
Loss of Inchicore - WestDublin_220_1	Loss of Letterkenny Tievebrack
Loss of Inchicore Poolbeg 220 2	Loss of Limerick Moneteen
Loss of Inchicore-WestDublin 220 2	Loss of Limerick Rathkeale
Loss of Inch-Irishtown 220	Loss of Lisdrum Louth
Loss of Irishtown Shellybanks 220	Loss of Lisdrum Shankill
Loss of Killonan Knockraha 220	Loss of Louth - Meath Hill
Loss of Killonan Shannonbridge 220	Loss of Louth – Ratrussan

Loss of Killonan Tarbert 220	Loss of Marina Trabeg 1
Loss of Kilpaddoge Knockanure 220 1	Loss of Marina Trabeg 2
Loss of Kilpaddoge Moneypoint 220 1	Loss of Maynooth Blake T
Loss of Kilpaddoge Moneypoint 220 2	Loss of Maynooth Rinawade
Loss of Kilpaddoge Tarbert 220 1	Loss of Maynooth Ryebrook
Loss of Knockraha-Raffeen 220	Loss of Mount Lucas - Thornsberry
Loss of Louth Tandragee ckt 1 275	Loss of Newbridge Blake T
Loss of Louth-Oriel (Woodland) 220	Loss of Portlaoise Dallow T
Loss of Maynooth - WestDublin_220_1	Loss of Portlaoise to Newbridge
Loss of Maynooth Shannonbridge 220	Loss of Raffeen-Trabeg 1
Loss of Maynooth to Woodland 220	Loss of Raffeen-Trabeg 2
Loss of Maynooth Turlough Hill 220	Loss of Ratrussan Shankill
Loss of Maynooth-WestDublin 220 2	Loss of Rinawade Dunfirth T
Loss of Moneypoint-Prospect	Loss of Shannonbridge - Dalton T
Loss of North Wall - Poolbeg	Loss of Shannonbridge - Somerset T
Loss of Oldstreet Tynagh	Loss of Shannonbridge - Ikerrin T
Loss of Poolbeg - Shellybanks_220_1	Loss of Sligo Srananagh 1
Loss of Prospect-Tarbert	Loss of Tralee - Oughtragh T
Loss of Agannygal Ennis	Loss of AD 220-110 1
Loss of Agannygal Shannonbridge	Loss of ARK 220-110 1
Loss of Aghada Whitegate	Loss of ARK 220-110 2
Loss of Ardnacrusha Drumline	Loss of CLA 220-110 1
Loss of Ardnacrusha Ennis	Loss of CLA 220-110 2
Loss of Ardnacrusha Limerick	Loss of CSH 220-110 1
Loss of Ardnacrusha-Singland	Loss of CSH 220-110 2
Loss of Arklow Ballybeg	Loss of CUL 220-110 1
Loss of Arklow Banoge	Loss of dn 380-220 1
Loss of Arva Carrick on Shannon	Loss of dn 380-220 2
Loss of Arva Gortawee	Loss of fla 220-110 1
Loss of Arva Navan	Loss of fla 220-110 2
Loss of Arva Shankill 2	Loss of GI 220-110 1
Loss of Athlone Lanesboro	Loss of GI 220-110 2
Loss of Athlone Shannonbridge	Loss of KLN 220-110 3
Loss of Athy to Portlaoise	Loss of KLN 220-110 4
Loss of Aughinish Kilpaddoge	Loss of KPD 220-110 1
Loss of Ballybeg Carrickmines	Loss of KPD 220-110 2
Loss of Baltrasna Corduff	Loss of kra 220-110 1
Loss of Baltrasna Drybridge	Loss of kra 220-110 2
Loss of Bandon Dunmanway	Loss of kra 220-110 3
Loss of Bandon Raffeen	Loss of Laois 400-110 1
Loss of Banoge to Crane	Loss of LDG 220-110 1
Loss of Baroda Newbridge	Loss of LOU 220-110 1
Loss of Bellacorick-Castlebar	Loss of LOU 220-110 2
Loss of Bellacorick-Moy	Loss of MAY 220-110 1
Loss of Binbane Tievebrack	Loss of MAY 220-110 3
Loss of Binbane-CF	Loss of Cushaling Portlaoise
Loss of Booltiagh Ennis	Loss of MP 220-110 1
Loss of Butlerstown Cullenagh	Loss of MP 380-220 1
Loss of Cahir - Barrymore T	Loss of MP 380-220 2
Loss of Cahir - Kill Hill	Loss of raf 220-110 1
Loss of Cahir Tipperary	Loss of raf 220-110 2
Loss of Cahir-Doon	Loss of SH 220-110 1

Loss of Carlow Kellis 1	Loss of wo 380-220 1
Loss of Carrick on Shannon - Arigna T	Loss of wo 380-220 2
Loss of Carrick on Shannon - Flagford	Loss of dunstown laois 400
Loss of Carrigadrohid Kilbarry	Loss of dunstown moneypoint 400
Loss of Carrigadrohid Macroom	Loss of Moneypoint Oldstreet 400
Loss of Cashla Cloon	Loss of Oldstreet Woodland 400
Loss of Cashla Dalton	Loss of Inchicore-Maynooth 220 2
Loss of Cashla Ennis	Loss of Kilpaddoge Tarbert 220 2
Loss of cashla galway 2	Loss of BAFD BCRM 275kV SC
Loss of cashla salthill	Loss of BAFD HANA 275kV SC
Loss of Cashla to Somerset T	Loss of BAFD KELL 275kV SC
Loss of Castlebar Cloon	Loss of BCRM HANA 275kV SC
Loss of Castlebar Dalton	Loss of CAST HANA 275kV SC
Loss of Cauteen Killonan	Loss of CAST TAND 275kV SC
Loss of CF clogher 110kV	Loss of CAST to KILR 275kV SC
Loss of CF-Corraclassy	Loss of Cool-magh 275 SC
Loss of CF-Srananagh 2	Loss of KELL KILR 275kV SC
Loss of Charleville Killonan	Loss of KELL MAGF 275kV SC
Loss of Clahane Tralee	Loss of KILR to TAND 275kV SC
Loss of Clahane Trien	Loss of MAGF TAMN 275 SC
Loss of Clashavoon Clonkeen	Loss of TAND TAMN 275 SC
Loss of Clashavoon Macroom 1	Loss of COLE1- COOL1-
Loss of Clashavoon Macroom 2	Loss of COLE1- LIMA1-
Loss of Clogher-Drumkeen	Loss of COLE1- Rasharkin
Loss of Clogher-Golagh T	Loss of COOL1- KILL1-CL
Loss of Clonkeen Clashavoon	Loss of COOL1- Limavady
Loss of Clonkeen Knockearagh	Loss of COOL1- stra
Loss of Cloon Lanesboro	Loss of DUNG to OMAH1-
Loss of Coolroe Kilbarry	Loss of Dungannon-Tamnamore
Loss of Corderry Arigna T	Loss of Gort Omagh
Loss of Corderry Srananagh	Loss of KELS1- RASH1-
Loss of Corduff to Mullingar	Loss of Killmallaght Strabane
Loss of Corduff to Platin	Loss of Omagh OmaS
Loss of Corduff-Ryebrook	Loss of Omagh Tremoge
Loss of Corraclassy Gortawee	Loss of OMAH1- STRA1-
Loss of Crane Wexford	Loss of Tamnamore Tremoge
Loss of Cullenagh to Dungarvan	Loss of BAFD 275 110 ckt 1
Loss of Cullenagh to Ballydine	Loss of CAST 275 110 ckt 1
Loss of Cullenagh-Waterford	Loss of cool 275 110 ckt 1
Loss of Cunghill Sligo	Loss of kell 275 110 ckt 1
Loss of Cushaling - Mount Lucas	Loss of TAMN 275 110 ckt 1
Loss of Cushaling Newbridge	Loss of TAND 275 110 ckt 1

Appendix 5: Glossary

AGU	Aggregated Generator Unit
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
MW	Megawatt
MWh	Megawatt hour
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
SO	System Operator
T&SC	Trading and Settlement Code
TCG	Transmission Constraint Group
TSO	Transmission System Operator
TUoS	Transmission Use of System
UUC	Unconstrained Unit Commitment
UR	Utility Regulator for Northern Ireland
VOM	Variable Operation and Maintenance

Appendix 6: SEM Settlement Cost Components

Dispatch Balancing Costs are made up of the following components:

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

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

CABBPO/ CAOOPO: Bid Price Only and Offer Price Only Payments and Charges, adjustment payment or charge to result in net settlement at the offer price for increments, or bid price for decrements, for undo actions on generators

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

CFC: Payments for additional fixed costs incurred, or charges for fixed costs saved from dispatching a unit differently to its market position, if not sufficiently covered through the unit's other payments or charges.

CTEST: Charges applied to units under test.

CUNIMB: Charges for imbalances and bids and offers accepted in balancing but not delivered, which were outside of a tolerance. Undelivered quantities are settled at the imbalance settlement price.

Appendix 7: Additional RA Request

This appendix outlines the TSOs' response to the RAs' request to rerun the 2022/2023 Plexos model using alternative fuel/carbon prices.

On 22 June 2022, the RAs requested the TSOs to re-run the Plexos model using alternative fuel/carbon prices.
This request was in line with F12.1.2 of the Trading and Settlement Code "*F12.1.2 The Market Operator's report must set out any relevant research or analysis carried out by the Market Operator and the justification for the specific values proposed. The report may, and shall if so requested by the Regulatory Authorities, include alternative values from those proposed and must set out the arguments for and against such alternatives.*"

The RAs requested that fuel and carbon prices are derived from an average of quarterly forward fuel prices and carbon prices for the preceding 12 months, that is from 10 May 2021 to 9 May 2022.

This is an alternative to the method currently used by the TSOs of taking future fuel/carbon prices, at a point in time, that is as close as possible before the model is finalised. For 2022/2023 Forecast, future fuel/carbon prices as per 09 May 2022 were used.

The fuel/carbon prices the RAs requested are significantly lower than those used (see Figure 5 below). The result of this rerun was that the Plexos model decreased from €532.94 to €320m (€213m difference).

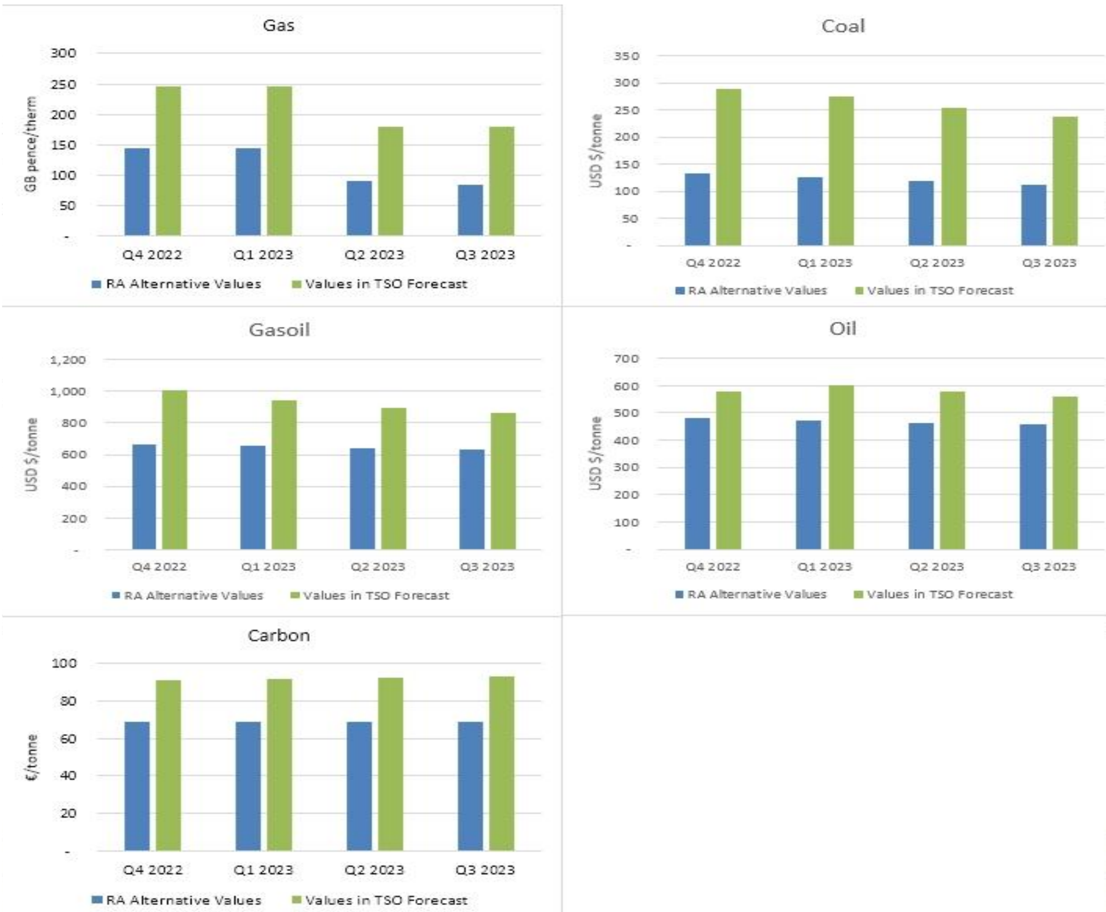

Figure 5: Forecast Model Fuel/ Carbon Cost Changes

Advantages of using this alternative fuel/carbon prices

- Taking an average of preceding year could potentially lead to a smoother value, where extreme prices are levelled out. This method may have merit in a world with more stable prices, where taking the future price from an average of dates rather than a single date could filter out possible noise in the futures market.
  While the method may have advantages in a stable world, as shown in Figure 6, recent prices have been volatile. Therefore, this method is not suitable for the 2022/23 Imperfections Forecast as addressed under the disadvantages section below.

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Figure 6: Forecast (FC) Model Fuel/ Carbon Cost Changes

Disadvantages of using alternative fuel/carbon prices

- Is it likely the future fuel forecast that the TSOs used will be more accurate than the method of averaging values of the preceding year:
  - The average gives too much weight to historic data, using the average results in much lower values than proposed by TSOs. The reasoning is they are weighted down by the relatively stable period of prices between May and Nov 2021 (green section in Figure 6 above)
  - Since Dec 2021, the wholesale fuel markets have been characterised by extreme market volatility, with record high prices, as well as average prices being significantly higher than the previous period. Using the 12-month averaging method does not fully capture these characteristics, as the average includes prices from May 2021 to Nov 2021.
  - As shown in Figure 6 above, the future prices taken 09 May 2022 appear to be in a sensible point of the recent range of fuel prices. They are not in the extreme highs of say early March 2022. Therefore, the averaging method does not appear to have any advantage in forecasting fuel prices, for 2022/23.
  - In general, as forecasts get closer to the time, they are more accurate. The TSOs' proposed values, as of 09 May 2022, would have the most up to date market dynamics factored into the future price. The averaged historic future prices would not have the current foresight factored into them.

The TSOs are strongly of the opinion that employing the averaged historical fuel and carbon is inappropriate for determining the forecast. The TSOs are very concerned, that if the 2022/23 imperfections charge is set based on the average historical fuel and carbon price data, there is a notable risk that the charge will not recover the required monies to fund the imperfections payments.

This must be considered in the context of the extant revenue position due to adverse movement in the current Imperfections year. As outlined in its submission to the RAs on the Imperfection's K-Factor the TSOs are carrying a significant under recovery year to date 2021/22, with this adverse position expected to continue and worsen by the end of September 2022. Available market cash has largely been expended and the TSOs expect to imminently begin drawing on Contingent Capital to fund any imperfections under recoveries until the end of the current tariff year. The TSOs note that the ultimate risk here is to Market Participants. As set out in Section 5, in the event the charge is insufficient to correct the under recovery and fund imperfections in 2022/23, once the contingent arrangements are fully drawn, the market will be shorted via the payment deferral mechanism under F.22.3 of the Trading and Settlement Code until additional money are available. The primary mechanism for addressing such a deficit is a within-year increase of the imperfections charge by employing a change to the charge factor (see Section 4). While a technically available option, the timeframes for approval of such a change would be a concern and the TSO are also cognisant of the increased uncertainty and possible implementation challenges this may pose for suppliers.

Appendix 8: External Consultants Report

Review of EirGrid/SONI PLEXOS Market Models for Imperfections Forecasting

Introduction

EirGrid and SONI has engaged Stantec and ESP Consulting to support them in a review of the PLEXOS market models which underpin the forecasting of imperfections costs. These costs mainly arise from the real-time management of network and operational constraints on the electricity system. As such, they reflect the difference between the contracted generation output apparent from the SEM ex-ante markets (DAM and IDM) and actual generation output consistent with the technical characteristics of the electricity system on the island of Ireland.

Eirgrid and SONI forecasts imperfection costs by configuring two PLEXOS models, an unconstrained model and a constrained model. The “unconstrained” model simulates generation scheduling without consideration of constraints, while the “constrained” model simulates actual despatch taking account of such constraints. Imperfections costs are estimated as the production cost difference between these two simulations with addition of some discrete system costs estimated separately in a supplementary (Excel) model.

The review was carried out by Soren Lautrup and Stuart Ffoulkes of ESP Consulting over 2 weeks in May 2022. It was conducted in close collaboration with key EirGrid/SONI staff from System Support and Analysis, Innovation and Research as well as Market Operations. The remainder of this note summarises the review approach and our key findings.

Approach and Scope

Overview

The main focus of the review was on the performance and calibration of the unconstrained model. Subsequently, the review was extended to also look at the constrained model, hence spanning both PLEXOS models involved in the imperfections forecast. The review did not include the supplementary model.

The main approach deployed in the review centred on unit-level examination of back-cast results over the period October 21 to April 22. This period was chosen to test the models’ performance following the recent major increases in fuel and CO_2 prices. The analysis was carried out at hourly granularity and spanned each of the main thermal units as well as the interconnectors and pumped storage.

When analysing results at an hourly granulation, continuous variations between the model and reality are inevitable and must be expected. Hence, the primary purpose was to ascertain whether the patterns of scheduling and dispatch produced by the models were broadly consistent with actual outcomes. In doing so, care was taken to avoid over-fitting the models to the particular historic results over this 7-months period.

For the unconstrained model, additional checks were carried out by comparing the consolidated volumes and Shadow Price (SMP Estimate) produced by the model with DAM SEMOpx clearing volumes and clearing prices. Time did not allow a similar consolidated check of the constrained model, but the EirGrid/SONI team carried out several checks of this model at our request.

Finally, key model input assumptions were reviewed. This included confirming that model fuel and CO_2 assumptions were in line with current forward market prices as detailed later.

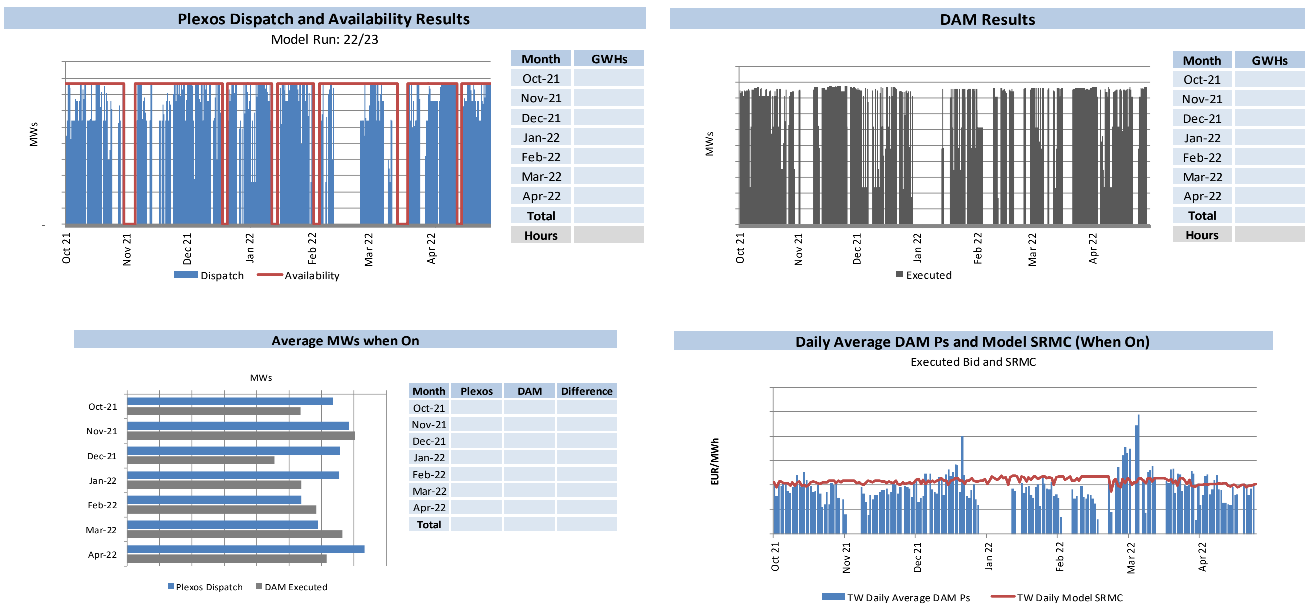
Unconstrained Unit Analysis

The unit analysis of the unconstrained PLEXOS model focussed on comparing:

- The model's unit scheduling with actual contract awards for that unit (executed bids) in the Day Ahead Market (DAM); and
- Model unit SRMC assumptions with both the executed (awarded) and maximum DAM price offered by the unit in question.

Figure 1 below illustrates the output produced for each of the units analysed (values and scales have been removed to preserve the anonymity of the unit illustrated in the sample):

Figure 1: Sample of Unit Analysis (Anonymised)



The price/SRMC analysis (lower right-hand graph) was supplemented by inspection of sample hourly bid curves constructed from the units' DAM PQ submissions.

Constrained Unit Analysis

For volumes, similar unit-level output was produced for the constrained model. The aim was to compare the dispatch suggested by the constrained model with data on actual generation provided by EirGrid/SONI. Time did not allow a full back-cast of pricing/cost results, but we did request that the EirGrid/SONI team confirm that the model's costing assumptions were consistent with currently submitted Commercial Offer Data (COD).

Summary of Findings

Unconstrained PLEXOS Model

The EirGrid/SONI unconstrained model embeds similar structure and limitations to the RAs Validated PLEXOS model. In particular, this model uses a simplified representation of GB and does not directly capture the Minimum Income Condition (MIC) constraints used by Euphemia.

The review identified an enduring tendency for CCGT capacity outside the Dublin Locational Capacity Constraint (LCC) to sell around 90% of its available capacity into the DAM. While the model mostly scheduled such plant to its full available capacity, actual executed bids tended to be around 10% lower. In turn, this increased scheduling reduced overall costs in the unconstrained model compared to actual DAM outcome. This bidding behavior was anecdotally confirmed by inspection of sample individual PQ curves. Whereas model SRMC assumptions were broadly in line with executed bids in the DAM, some CCGT participants priced the top-end of their capacity well above this level (which typically did not get executed in the DAM) or did not offer this capacity into the DAM at all. This bidding behavior has now been reflected in the EirGrid/SONI unconstrained PLEXOS model.

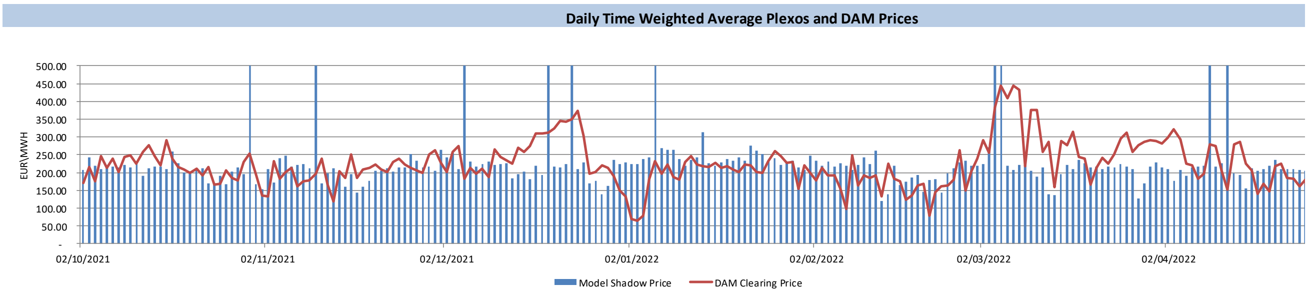
Furthermore, as part of the review some assumptions were updated or changed:

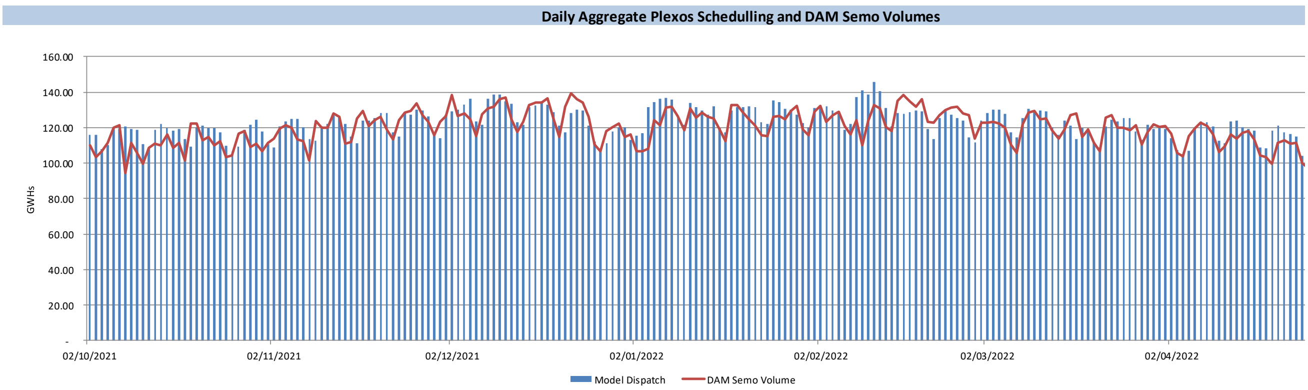
- For some units, forced outage assumptions were updated to avoid giving one-off large incidents undue weight (i.e., anomalous long-term outages); and
- The modelling of interconnectors was changed to apply QEX data (rather than actual BM flows) to better reflect the timeframe of interconnector flow determination post Brexit.

Subject to these corrections, our unit-by-unit analysis suggests that the model offers a good representation of the real-world unconstrained schedule. We found that the pattern of the model's scheduling generally is consistent with the observed DAM awards over the selected period.

This conclusion is further corroborated by the consolidated comparison graphs shown in Figure 2 below. These graphs compare the model (shadow) price and volumes with DAM SEMOpx clearing prices and volumes, respectively. As illustrated, the model undershot the SEMOpx clearing prices towards the end of December as well as in the month of March, while overshooting in January. However, these deviations are not surprising given that model fuel prices are set with reference to quarterly forward products while the 7-months period analysed included extreme monthly and daily volatility. Furthermore, it is important to avoid overfitting the model to this specific 7-month period. Overall, we find the general alignment between the model and real-world both with respect to price and volumes reassuring.

Figure 2: Consolidated Price and Volume Comparison





Constrained Model

The analysis included detailed review of model dispatch against actual generation/flows across the major units with particular attention to interconnectors and pumped storage. While necessarily a simplification of reality, we found that the model offered a good representation of actual dispatch.

As noted above, detailed hourly review of differences between the constrained model and actual dispatch was limited to volumes. However, Eirgrid/SONI team confirmed that model unit cost assumptions are reflective of currently submitted unit COD.

Fuel Price Assumptions

While spot prices have fallen from previous highs, forward prices remain elevated and the 22/23 model runs reflect this market expectation. We have checked the fuel and carbon price assumptions and can confirm that they were consistent with current ICE forward curves at the time of the 22/23 model run:

- Coal: API2 Rotterdam Coal Futures;
- Fuel Oil: Fuel Oil 1% CIF NWE Cargo Futures;
- Gas: UK Natural Gas Futures;
- Gas Oil: Gas Oil 0.1% CIF NWE Cargo Futures; and
- CO_2: EUA Futures.

Forecast Uncertainty

We note that the current situation in Ukraine creates enormous uncertainty with regard to future gas prices, while at the same time materially limiting the liquidity in longer-dated forward market products. It follows that:

- The fuel prices which underpin the imperfections forecast are subject to more than usual uncertainty; and
- Market developments could materially alter relative fuel prices and hence the modelled merit order and accompanying imperfections forecast. This uncertainty is inherent in the current unprecedented conditions.

Finally, the SEM is likely to be tight for capacity in 2022/23, especially in the Dublin LCC. This means that the out-turn situation is likely to be unusually sensitive to the impact of unit outages.