Appendix 1
XXX-XX-XXX

Forecast Imperfections Revenue Requirement for Tariff Year 1st October 2012 – 30th September 2013

30th April 2012

SEM-12-045 (1)

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Executive Summary

This year's submission by the Transmission System Operators (TSOs) represents the forecast component of the Imperfections Revenue Requirement. 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. Adjustments for previous years are not included in this submission, but are considered in setting the Imperfections Charge.

The forecast of the Imperfections revenue requirement is €142.1 million in nominal terms for the 12 month period from 1st October 2012 to 30th September 2013. The forecast for previous Tariff Year (2011-12) was €142.7 million.

Constraint costs represent the largest proportion of the Imperfections Revenue Requirement and this paper describes the methodology employed in the forecasting process. Constraints are a feature of the Single Electricity Market (SEM) and are recognised as part of the SEM High Level Design[1].

This year there are a number of key factors which have influenced the forecast:

- It has been assumed that the Carbon Price Floor is implemented in Great Britain and Northern Ireland from April 2013. This has an impact on the price of generation in Northern Ireland, and also influences forecast interconnector flows.
- Fuel prices, carbon prices and heat rates were used to approximate participant bids for each generator. Compared to the Tariff Year 2011-12 forecast there has been an increase in gas and coal prices.
- The primary operating reserve requirement has been reduced from 81% to 75% of the largest infeed on the system, in line with current operational policy.
- Interconnection has increased, with the addition of the East West Interconnector (EWIC), allowing greater trading between SEM and Great Britain.

This forecast of the Imperfections revenue requirement is based on a number of assumptions and expected conditions for the Tariff Year 2012-13. However, the Transmission System Operators have also outlined risk factors which relate to low probability events that could have a major impact on constraint costs for the year were they to occur.

[1] **AIP/SEM/42/05**

1. Introduction

This submission to the Commission for Energy Regulation (CER) & the Northern Ireland Authority for Utility Regulation (NIAUR), collectively known as the Regulatory Authorities (RAs), has been prepared by EirGrid and SONI in their roles as the Transmission System Operators (TSOs) for the island of Ireland.

The submission reflects the TSOs' forecast of expected Imperfections revenue required for the 12 month period from 1st October 2012 to 30th September 2013 inclusive, referred to as the Tariff Year 2012-13. 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 Imperfections revenue requirement also includes a forecast of Energy Imbalances, Make Whole Payments and Other System Charges for the Tariff Year 2012-13.

This Imperfections revenue requirement is a major element in determining the Imperfections Charge. However, other elements also contribute to setting this charge, including the Imperfections pot K factor, which adjusts for previous years as appropriate, and the forecast system demand for the tariff year. The Imperfections Charge is levied on suppliers as a per MWh charge on all energy traded through the SEM by the Single Electricity Market Operator (SEMO).

The TSOs' forecast for the Imperfections revenue requirement is €142.1 million in nominal terms for the Tariff Year 2012-13. A detailed breakdown of the forecast individual components is contained in Section 9.

This estimate of the Imperfections revenue requirement 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 specifically recoverable through the TUoS tariff and SSS tariff in Ireland and Northern Ireland under the respective regulatory arrangement pertaining.

1.1. Context for Tariff Year 2012-2013

There are a number of factors which may influence the forecast Constraint costs, and as such the forecast Imperfections revenue requirement, for the Tariff Year 2012-13. The most significant influencing factors are described below. In addition to these factors, Intra-Day Trading will be effective in SEM prior to the start of the Tariff Year 2012-13. The TSOs have no operational experience of Intra-Day Trading and it is assumed that it will not significantly influence constraint costs.

1.1.1. Fuel and Carbon Costs

When compared to the Tariff Year 2011-12 forecast, there has been an increase in gas and coal prices, while the forecast oil and distillate prices have reduced from last year's forecast. These changes have influenced the Commercial Offer Data calculated for each generator as an input to the model. The increases forecast in gas and coal prices have had a much greater influence on forecast constraint costs than the reduction in distillate and oil prices, due to the current generation portfolio.

It has been assumed that the Carbon Price Floor[2] is implemented in Great Britain and Northern Ireland from April 2013. In the model, this has an impact on the price of generation in Northern Ireland, in particular coal and to a lesser extent gas. It also has a notable effect on interconnector flows.

1.1.2. Increased Interconnection

Interconnection with Great Britain has more than doubled with the inclusion of the East West Interconnector (EWIC) in this year's forecast in addition to the Moyle Interconnector. EWIC is assumed to be commissioned and fully operational at the start of the Tariff Year 2012-13.

Forecast interconnector flows are price based and are primarily imports to SEM, reducing the unconstrained production cost at times. There are also some instances of forecast exports, particularly in the latter half of the year, and at times of high wind.

Additional interconnection has a twofold effect on system reserve requirements:

(i) up to 50 MW of static reserve is available from EWIC when scheduled flows allow it, reducing constraint costs at times by lowering the spinning reserve requirement, and

(ii) the largest possible infeed to the system has increased from 450 MW to up to 500 MW. The system reserve requirement is a percentage of the largest infeed to the system during any period, so if high import flows are scheduled on EWIC, reserve costs may increase for that period. However, as noted above, imports would be expected to have the effect of reducing the unconstrained production cost at times

1.1.3. Reserve

The system reserve requirements are set as a percentage of the largest infeed to the system. For Primary and Secondary Operating Reserve, this requirement has been set to 75% of the largest infeed on the system, in line with current operational policy[3]. This has reduced from a requirement of 81% used in last year's forecast. The reserve requirement is also now modelled as a dynamic, rather than fixed, requirement as a function of the largest infeed in any period. With additional interconnection, up to 100 MW of static reserve from interconnection is assumed to be available at times, scheduled flows permitting. These factors should all contribute to reducing constraint costs associated with reserve. It is also assumed that the Turlough Hill units provide the same services as previously.

[2] http://www.hm-treasury.gov.uk/press_33_11.htm
[3] www.eirgrid.com/media/Operating%20Reserve%20Requirements%2021%20April%202011.pdf

2. Overview of Imperfections

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. As noted in Section 1, adjustments for previous years are not included in this submission, but are considered in setting the Imperfections Charge.

The diagram below illustrates how these are related; and how they are used to derive the SEM Imperfections Charge.

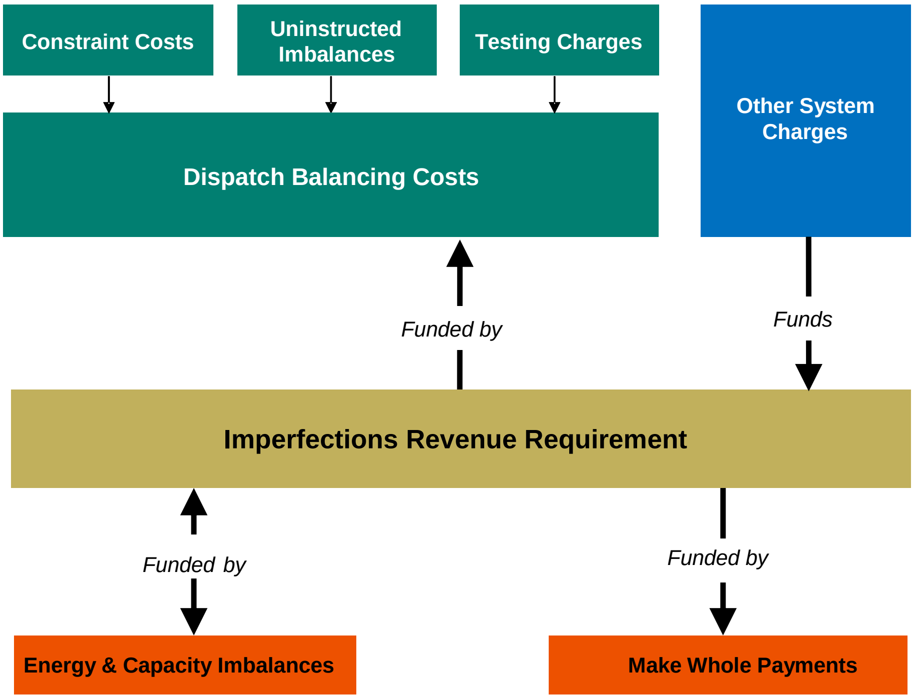

Figure 1 – Relationship between Dispatch Balancing Costs and Imperfections

The three components of Dispatch Balancing Costs, namely Constraints, Uninstructed Imbalances and Testing Charges are described in further detail in Sections 3, 4 and 5 respectively. Other System Charges are detailed further in Section 6. Section 7 describes Energy Imbalances and their interaction with DBC, while Section 8 discusses Make Whole Payments.

3. Constraint Costs

3.1. 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 software's 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 3.2 below describes the main categories of issues that can lead to a difference between the market schedule and actual dispatch and hence constraint costs.

3.2. Why do Constraint Costs Arise?

3.2.1. 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.

3.2.2. 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.

3.2.3. Perfect Foresight

The market schedule of generation, which is used for energy settlement, is produced after real time (*ex post*) by the market software using actual demand, actual wind output and known generator availabilities. However, operating the system in real-time, the TSOs do not have this perfect foresight. They must plan and operate the system to account for possible variations in these parameters.

3.2.4. 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 software assumes that generators can synchronise and reach their minimum load level in 15 minutes, whereas in reality this may take much longer; the market software 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.

3.3. Managing Constraint Costs

Constraint costs will inevitably arise due to the factors described in Section 3.2 above and they are also dependent on a number of underlying conditions. Some of these conditions, such as fuel costs, generator forced outages, trips, transmission network availability and system demand are outside of the TSOs' control. However, the TSOs continually monitor constraint costs and the drivers behind them to ensure that costs which are within their control are minimised. 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 of 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 6.
- Ongoing review of dispatch policy. One example of a change identified through this ongoing review is the implementation by the TSOs of a revised reserve policy, reducing the primary and secondary operating reserve requirements from 81% to 75%.
- Wind and Load forecasting, which involves continually working with vendors to improve forecast accuracy.
- Examining additional Ancillary Services which will provide a system benefit, through the System Services Review Consultation[4].

[4] http://www.eirgrid.com/operations/ds3/ds3programmeoffice/

3.4. Modelling Constraint Costs

3.4.1. 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.

3.4.2. 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 version 10.0, dated 21st October 2011.
- 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.

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 1.

Subject	Assumption
Data Freeze	All input data for the PLEXOS model was frozen at 29th February 2012.
Forecast period	The forecast period is from 1st October 2012 to 30th September 2013.
Currency	All costs are modelled in euro.

Fuel and Carbon Prices	Fuel prices for 2012/13 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters[5] and HEREN[6] reports and information available from the ICE futures website[7]. Carbon costs are also forecast and used, along with fuel costs, to calculate simulated bids for generators and interconnector units in SEM and BETTA. These are then input to PLEXOS to simulate participant commercial offer data for each unit Note that the Carbon Price Floor is assumed to take effect in the United Kingdom (therefore including Northern Ireland) on 1st April 2013.
Participant behaviour	It is assumed that generators bid according to their short run marginal costs in SEM in line with the Bidding Code of Practice[8]
Demand Forecast	The demand is based on the 2012/13 median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2012-2021[9].
Generator Schedule Outages	2012 and 2013 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 scheduled transmission outages are modelled in PLEXOS. Forced transmission outages are not modelled.
Operating Reserve	Primary, secondary and tertiary 1 and 2 reserve requirements are modelled.[10] 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[11].
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 200 MW S-N. This assumption has been made based on TSO operational experience.

[5] http://thomsonreuters.com/products_services/financial/financial_products/commodities/energy/
[6] http://www.icis.com/heren/
[7] https://www.theice.com/homepage.jhtml
[8] The Bidding Code of Practice - AIP-SEM-07-430
[9] http://www.eirgrid.com/media/All-Island%20GCS%202012-2021.pdf
[10] http://www.eirgrid.com/media/Operating%20Reserve%20Requirement.pdf
[11] http://www.eirgrid.com/media/Transmission%20Constraint%20Groups%20Version%201.2.pdf

Interconnection	An unconstrained model of BETTA was developed and combined with an initial run of the SEM unconstrained model to model flows on the Moyle Interconnector and EWIC. A “hurdle rate” was applied in the model to each interconnector to reflect market differences, capacity payments, network charges and a risk element. The price difference must exceed the hurdle rate before trading can take place[12].
Intra-Day Trading	No explicit change has been made to reflect Intra-Day Trading in the PLEXOS model as assumptions regarding the expected trading post Intra-Day release are not known.
BETTA Unconstrained Model	A single-node model of the BETTA market was created. Generators bid in short run marginal costs, with Nash-Cournot competition implemented to approximate a market price for the region.

3.4.3. 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.

A single-node model of the BETTA market was created. Generators bid in short run marginal costs, with Nash-Cournot competition implemented to approximate a market price. This model was used in conjunction with the unconstrained SEM model to produce forecast flows on the Moyle Interconnector and EWIC.

[12] The “hurdle rate” is used to account for costs and other factors that would affect the decision of a rational trader other than pure energy price differential between the two interconnected markets, such as Capacity Payment Mechanism in SEM, GB network charges, and a risk factor to account for ex-post pricing in SEM.

3.5. Specific Constraint 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:

- Perfect foresight;
- Specific transmission system constraints;
- Specific reserve constraints;
- Market modelling assumptions;
- System security constraints;
- Other factors.

These are discussed, in detail, below.

3.5.1. Perfect foresight

The market schedule is determined *ex post* with perfect knowledge of all outturn data. In contrast, the system is dispatched in real time using the best information available at that time. This disparity results in differences between the market schedule and actual dispatch, thereby increasing constraint costs. This perfect foresight effect cannot be captured in the PLEXOS modelling as the model also has perfect knowledge of all outturn data. The main drivers of these differences arising from perfect foresight are described below.

3.5.1.1. Changes to demand and generator availability

Since it is calculated *ex post*, the Unconstrained Unit Commitment (UUC) (initial) market schedule[13] has the benefit of perfect foresight of changes in demand and generator availability. The TSOs do not have this advantage and must respond to such changes as and when they happen.

Following the tripping of a generator, the TSO must activate reserves and will typically have to replace the lost generation using fast start plant e.g. peaking units, at a significant cost. Other System Charges, such as Trip and Short-Notice Declaration charges, are levied on generators who fail to provide necessary services to the system[14]. OSC therefore act to take account of the immediate, short-term costs incurred from these events. The monies paid by generators are then used to offset the DBC costs incurred.

However, in addition to replacing lost generation capacity immediately after the event, the TSOs are also unaware of how long the plant will be unavailable for in real time operations. This may result in re-dispatching a number of plant to ensure that there is adequate capacity to meet demand and reserve requirements where the expected return of the generator is uncertain. The UUC market schedule on the other hand, since it knows that the generator will trip, can schedule the most economic replacement plant in anticipation of the tripping (e.g. by starting another unit in the market several hours before the tripping). It also has perfect knowledge of the duration of the unavailability and can schedule plant in as optimal a

[13] In the Trading and Settlement Code, the UUC is referred to as the MSP software.
[14] Harmonised Other System Charges Consultation, April 2012: http://www.eirgrid.com/media/OSCConsultation2012.pdf

manner as possible. This continuous information asymmetry results in considerable constraint costs over the year.

3.5.1.2. Impact of wind predictability

Wind is inherently a variable resource. The UUC market schedule, with perfect foresight, can schedule the most economic generation to balance this variability as it knows exactly the level of wind output in every period. The TSO, on the other hand, since it is not always aware of the timing or extent of these variations, must balance them using a combination of part-loaded plant and more expensive fast-start plant. This less optimal schedule will cause an increase in constraint costs.

3.5.1.3. Long Start-Up and Notice Times, Lack of Flexible Plant

The generation portfolio has changed in recent years due to a number of plant closures, and the fact that new build has tended to be larger, less flexible units. This deficit of mid-merit units that can start with relatively short notice periods has resulted in a reduction in portfolio flexibility for reacting to unexpected changes in generation and demand. Previously, when mid-merit units were available, uncertainty over generation, wind and load could be managed within 1 to 2 hours using these flexible mid-merit generator units.

At present, any potential capacity shortages due to generation, wind and load uncertainty in the near future require commitment decisions to be made a number of hours in advance due to the long notice periods required by the generator units available to meet these shortages.

With the introduction of Intra-Day Trading, it is possible that the level and direction of interconnector flows will change closer to real time. This in turn means that output from other generators will have to be scheduled differently. Plant notice times will have to be respected, meaning that operators are required to call units with long notice periods further from real time when there is greater uncertainty about forecast wind, demand, and levels of interconnector flows. This increases the likelihood that dispatch diverges more from the optimal solution.

These commitment decisions are made to mitigate against the risk of a capacity shortage and to ensure that sufficient replacement reserve is maintained to deal with any further changes to unit availability, interconnector scheduled flows or forecast demand or wind. Availability of generation with shorter notice times and/or greater flexibility would mean that such commitment decisions could be made nearer to real-time and with better information. Availability of key reserve providers will alleviate this issue somewhat, however with higher levels of wind and interconnection, managing the system in real time with the current generation portfolio remains a challenge.

3.5.1.4. Moyle schedule set D-1

This element has been removed as perfect foresight effects of Intra-Day Trading and interconnector scheduling have been captured in the provision above regarding long start-up and notice times.

3.5.2. Specific Transmission System Constraints

Transmission line limits are modelled in PLEXOS. As in previous years there were some other transmission system constraints which it is not possible to model in PLEXOS and for which specific provision had to be made. A brief description of these is given in the following section.

3.5.2.1. Limited Transmission Scheduled Outages in PLEXOS

Transmission outages can result in additional transmission constraints. These additional constraints may include requirements to run out-of-merit generation, restrictions on the maximum tie-line flow and localised export constraints. This year a number of the significant transmission outages have been incorporated into the PLEXOS model based on the expected transmission outage programme as of the data freeze dated 29th February 2012. No specific provision for other expected transmission outages has been included in this submission.

It should be noted that the principal, most onerous N-1 contingencies were included in the PLEXOS model. It was assumed that other contingencies had a negligible effect on constraint costs or could be solved post contingency.

3.5.2.2. Forced Transmission Outages

Forced transmission outages can result in additional transmission constraints, through requirements for out-of-merit generation, restrictions on the maximum tie-line flow or localised export constraints. As such, the outage of certain items on the transmission system can potentially increase DBC significantly. However, due to the unpredictable nature of such outages, it is not possible to calculate a specific provision for this submission or to include them in the PLEXOS model. As such, forced transmission outages are identified as a risk rather than an explicit cost.

3.5.3. Specific Reserve Constraints

PLEXOS includes requirements for primary, secondary and tertiary operating reserves. In addition, regulation and replacement reserve requirements are also met through the constraints in the PLEXOS model.

Turlough Hill is a source of spinning reserve. However, while reserve provision by the units is modelled in PLEXOS, it is not possible to model all of the operating modes. In particular, the minimum generation mode allows provision of reserve at very low loads but at a much lower efficiency than normal operation. This efficiency reduction effectively reduces the total energy available in the dispatch. This energy must be replaced (by the marginal plant), resulting in additional constraint costs over the day.

3.5.4. Market modelling assumptions

The UUC market schedule software makes a number of modelling assumptions and simplifications that are necessary to allow it to generate robust solutions in a reasonable length of time. PLEXOS also makes similar modelling assumptions. These simplifications can result in infeasible schedules that would be impossible in reality, even in the absence of any transmission system constraints. The consequence is that additional constraint costs will arise.

3.5.4.1. 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.

3.5.5. System Security

3.5.5.1. 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.

3.5.6. SO Interconnector Trades

Under the Trading and Settlement Code, the TSOs are permitted to make SO Interconnector trades after gate closure on any spare capacity on the Interconnectors. Such spare capacity comprises any unsold capacity remaining after capacity auctions and any capacity that is either not offered or is not scheduled based on the ex-ante market schedule.

To date, the SO Interconnector trades on Moyle have been used for security of supply, to maintain system reserve levels and to provide emergency energy flows. The additional energy is usually required at short notice (for example over the evening peak) to maintain system security. In events where the system frequency drops below a certain level, the Moyle Low Frequency Service automatically imports an agreed amount of active power to assist the relevant System Operator with the stabilisation of the system frequency. An Emergency Response facility is also available for system security events. A Moyle High Frequency Service is also in service. This service automatically exports power to the other System Operator whenever the frequency increases above certain predefined limits. It is envisaged that a similar contracted service will be entered into for EWIC and that it will operate in a similar manner.

There are many factors affecting the cost of SO Interconnector trades that are outside of SONI and EirGrid’s control. For example the price paid for the energy can be very variable.

An explicit provision for constraints costs arising from SO Interconnector Trades is included in this submission. This provision is the estimated net effect on constraints of the SO Interconnector Trades for the Low and High Frequency Service on Moyle and on EWIC.

It should be noted that no provision has been made for SO Interconnector trades other than those triggered under the Low/High Frequency Service. While SO Interconnector trades may be required to maintain system security in exceptional circumstances, these are unplanned events, which are difficult to predict, and as such are identified as a risk rather than an explicit cost.

The "EirGrid Group Policy for Implementing Scheduling and Dispatch Decisions SEM-11-062[15]" document provides an explanation as to how the TSOs will give effect to the SEM-11-062 decision in scheduling and dispatching generation on the island. This includes the TSOs counter-trading on interconnectors after gate closure. It is assumed that any counter-trading by the TSOs would be cost-neutral.

3.5.7. Treatment of Wind with Non-Firm access in PLEXOS

The PLEXOS model does not differentiate between wind generation units with firm and non-firm access. In recognition of this, a provision has been made to reflect the effect of wind with non-firm access dispatched down over the year. Dispatching down of wind generation normally represents a cost in terms of constraints as in order to maintain supply-demand balance, price making generation has to be dispatched to meet demand which was met in the market schedule by price taking wind generation. However, with the implementation of a revision to SEM rules[16] around the treatment of wind generation with non-firm access, dispatching down wind with non-firm access will not result in this cost in terms of constraints, as any dispatched down wind with non-firm access will not be scheduled in SEM.

A negative provision is included in this submission to offset the over-estimation of the cost of dispatched down wind in the PLEXOS model due to a portion of that wind generation having non-firm access.

[15] http://www.eirgrid.com/media/Implementing%20SEM%20Decision%20SEM%2011%20062%20in%20Real%20Time%20Operations.pdf
[16] http://www.sem-o.com/MarketDevelopment/ModificationDocuments/110607%20SEM%20C%20Decision%20on%20Mod_43_10.pdf

4. Uninstructed Imbalances

4.1. Overview of Uninstructed Imbalances

Uninstructed Imbalances[17] and constraint costs are related, with uninstructed imbalances having a direct effect on constraints costs, as TSOs redispatch 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 economical 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.

4.2. 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.

While analysis of uninstructed imbalance data in SEM so far indicates that Uninstructed Imbalances have resulted in a net benefit to date, it is assumed that any net benefit accrued is offset by the corresponding constraint costs incurred due to remedial 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. Therefore, it is assumed that any net benefit from Uninstructed Imbalances that may accrue will offset the related constraint costs.

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

5. 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 increases 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 highly 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.

6. 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 1st February 2010.

These charges are specified in the Transmission Use of System 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[18]. 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.

[18] Trading and Settlement Code V10.0, 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.”

7. Energy Imbalances

A continuous balance between system generation and system demand plus losses is required to maintain a secure system. As a result of this, the sum of the loss adjusted Market Schedule Quantities (MSQs) on which generators are paid Energy Payments should equal the loss adjusted net demand on which suppliers pay Energy Charges.

Energy Imbalances occur in SEM in the event that the sum of Energy Payments to generators does not equal the sum of Energy Charges to suppliers. There is an inherent link between Energy Imbalances and Constraints. An Energy Imbalance will generally impact Constraint costs in the opposite direction, artificially increasing or decreasing the total Constraint Costs. For example, Energy Payments will exceed Energy Charges if the sum of the MSQs is greater than the net demand and will result in an Energy Imbalance out of SEM (i.e. more paid out than recovered). In reality, in this example the system would have been balanced and the dispatch of generators will equal actual demand (plus losses) on the system. Constraints are calculated as the difference between the MSQs and the dispatch of each generator. When the sum of the MSQs exceeds the sum of dispatched generation, it will result in a net reduction in the system Constraint costs, as more generators will appear constrained down/off than will be constrained on/up.

Energy Imbalances, although generally negligible, arise from time to time due to features in the SEM rules. For example, if the Dispatch Quantity of a testing generator unit deviates from the Nomination Profile submitted to SEM, which could occur either due to events that occur during the testing or for system security reasons, an energy imbalance may arise. In this submission, it is assumed no Energy Imbalances will arise and no provision in terms of Energy Imbalances with corresponding additional/reduced Constraints is included. If energy imbalances do occur, they are assumed to have an equal and opposite effect on constraints and will offset any increase or decrease accordingly.

8. Make Whole Payments

The purpose of Make Whole Payments is to make up any difference between the total Energy Payments to a generator and the production cost of that generator on a weekly basis. As such, Make Whole Payments are a feature of the SEM rules and are generally independent of dispatch and DBC. Due to the design of the SEM rules, Make Whole Payments rarely arise. SEMO are responsible for administering all Make Whole Payments and they are funded by Imperfections. A small provision for the Make Whole Payments for the 2012/13 Tariff Year is included in this submission.

9. Results

This section contains the TSOs' forecast Imperfections revenue requirement for the Tariff Year 2012-13. The results of the forecast constraint costs from both the PLEXOS model and the supplementary modelling are outlined in Sections 9.1 and 9.2 respectively. A summary of how the total forecast Imperfections revenue requirement is determined is then outlined in Section 9.3.

9.1. PLEXOS Results

The forecast cost of the constraints modelled using the PLEXOS model for Tariff Year 2012-13 is **€115.7 million**. This PLEXOS model portion of the forecast has increased slightly from the forecast costs of €114 million for the Tariff Year 2011-12. While the overall change in the forecast constraint costs coming from the PLEXOS model is not large, there are a number of key drivers underlying the forecast costs that have changed, but have ultimately offset each other.

The most significant changes to forecast constraint cost drivers in the PLEXOS model are:

- **Carbon Price Floor:** It has been assumed that the Carbon Price Floor is implemented in Great Britain and Northern Ireland from April 2013. This assumption increases the relative cost of generation in Great Britain and Northern Ireland compared to that in Ireland, affecting both the flows on the Interconnectors and increasing the cost of some regional system security and reserve constraints.

- **Commercial Offer Data:** Fuel prices, carbon prices and heat rates were used to approximate participant bids for each generator. Compared to the Tariff Year 2011-12's forecast prices, there has been an increase in the simulated prices bid by gas and coal fired generation by 16% and 14% respectively. While bid prices for oil and distillate fired generation used are somewhat lower than last year's forecast, gas and coal have a significantly greater impact on the total forecast costs due to the current portfolio of generation on the island. Higher simulated bid prices for the current tariff year will increase production costs in both the constrained and unconstrained models, but with the net effect of increasing constraint costs.

- **Operating Reserve Requirements:** The primary and secondary operating reserve requirements has been reduced from 81% to 75% of the largest infeed in this year's model in line with current operational policy. This reduction, coupled with the dynamic calculation of the reserve requirement in each period based on the largest infeed (instead of a fixed requirement based on the largest infeed across the year used in last year's model), has a moderating influence on forecast constraint costs.

- **Interconnection:** In addition to the Moyle Interconnector, the PLEXOS model now includes EWIC, which is assumed to be commissioned and fully operational at the start of the Tariff Year. Additional interconnection has a twofold effect on system reserve requirements:
    - up to 50 MW of static reserve is available from EWIC when scheduled flows allow it, reducing constraint costs at times by lowering the spinning reserve requirement, and

  - the largest possible infeed to the system has increased from 450 MW to up to 500 MW. If high import flows are scheduled on EWIC, reserve costs may increase for that period[19].

- **Generator Availability:** The Turlough Hill units are assumed to be operational for the Tariff Year 2012-13. As these units were only assumed available for part of the Tariff Year 2011-12 and may provide operating reserve, this will have a beneficial effect on forecast constraint costs.

9.2. Supplementary modelling results

The individual components of supplementary modelling, which take account of specific external factors that cannot be captured in PLEXOS modelling, were outlined and discussed in Section 3.5. The forecast cost of the constraints modelled by supplementary modelling for the Tariff Year 2012-13 is **€26.3 million**. This represents a reduction of €2.3 million from the 2011-2012 Tariff Year. The results of the supplementary modelling process are summarised in the table below:

Description		Forecast (€m)
Perfect Foresight Effects	Changes to demand and generator availability	7.6
	Wind predictability	9.5
	Long Start-Up and Notice Times	3.5
	Moyle schedule set D-1	0.0
Specific Reserve Constraints	Turlough Hill	2.8
Market Modelling Assumptions	Block Loading	0.6
	Hydro limitations & issues	0.0
System Security constraints	Capacity Testing & Performance Monitoring	2.8
Wind with non-firm access	Plexos treatment of wind generation with non-firm access	-0.7
System Operator Interconnector Trades		0.3
Supplementary Modelling: Total		**26.3**

[19] As noted in Section 1.1.2, imports would be expected to have the effect of reducing the unconstrained production cost at times

The most significant drivers of the change in forecast constraint costs in the supplementary modelling are:

- **Lower Perfect Foresight Effects:** a reduction in the perfect foresight effects for changes to demand and generator availability and wind predictability. These are predominantly due to lower overall production costs in the unconstrained PLEXOS model and also due to the removal of the provision for the Moyle schedule set at D-1.

- **Specific Reserve Constraints:** The provision to account for the reduced efficiency of Turlough Hill when dispatched in Min Gen mode has increased from last year, due to the assumption that Turlough Hill is available for the full year, rather than only part of the year as assumed in last year's forecast.

- **Wind with non-firm access:** This new provision reduces the forecast constraint costs in the supplementary modelling. This reduction offsets the forecast constraint costs over-estimated by the PLEXOS model, which does not differentiate between wind generation units with firm and non-firm access when wind is dispatched down.

9.3. Summary of Imperfections Revenue Requirement

A summary of the forecast Imperfections revenue requirement for the Tariff Year 2012-13, including a breakdown by component, is presented in the Table below.

Component	Forecast (€m)
Dispatch Balancing Costs	
- Constraints	**€142.0**
- Uninstructed Imbalances	**€0.0**
- Testing Charges	**€0.0**
Make Whole Payments	**€0.1**
Net Imbalance between Energy Payments and Energy Charges	**€0.0**
Net Imbalance between Capacity Payments and Capacity Charges	**€0.0**
Other System Charges	**€0.0**
FORECAST IMPERFECTIONS REVENUE REQUIREMENT	**€142.1**

10. Risk Factors

There are a number of risk factors that could have a significant impact on the level of Dispatch Balancing Costs. The main factors are highlighted below, with some discussion on the nature of these risks and potential mitigation measures. These factors have not been accounted for in the total forecast Imperfections revenue requirement but could individually result in a significant deviation from this constraint forecast if they arose.

10.1. Specific Risks

10.1.1. Intra-day Trading

In order to become compliant with EU Congestion Management Guidelines for Cross Border Trade, the Single Electricity Market (SEM) is set to change with the introduction of Intra-Day Trading arrangements in July 2012. At the time of forecast, the TSOs have no operational experience of Intra-Day Trading and as such it is difficult to predict the impact this will have on DBC. If participant behaviour diverges greatly from that predicted in the model, constraint costs could change significantly.

10.1.2. Interconnector Flows

Interconnector flows have been forecast using price-based differential between the unconstrained SEM and BETTA markets, with hurdle rates being applied on the Moyle Interconnector and EWIC. As with Intra-Day Trading, participant behaviour could result in interconnector flows that differ greatly from those forecast. This, in turn, could result in constraint costs changing significantly.

10.1.3. Significant Fuel Price Variations

The fuel prices used in the PLEXOS modelling process are based on a forecast of long term fuel prices determined at the beginning of 2012. Recent experience would suggest that there is significant volatility in some fuel prices. A general increase in fuel prices would lead to higher generator running costs and hence higher Dispatch Balancing Costs. Divergence in the relative price of fuels could also lead to an increase in Dispatch Balancing Costs. Similarly, a reduction in the relative divergence of fuel prices could lead to a reduction in Dispatch Balancing Costs.

10.1.4. High Impact, Low Probability Events (HILPs)

In respect of the constraint forecast, HILPs are rare 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 as soon as possible.

10.1.5. Poor Generator Availability and/or Generation Station Closure

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

10.1.6. Hydroelectric generator constraints

Changes to how hydroelectric generators are classified in SEM may impact on constraint costs. At the time of forecast, while it was assumed that certain units would re-register as price-taking generation in the market, in the absence of operational experience of this, it was impossible to determine the potential effect on constraints, and as such no explicit provision was made

10.1.7. Overrun of outages

Outages by their nature reduce the flexibility of the system due to unavailability of generation and/or transmission plant. Overrun of any outage will extend this state of reduced flexibility and may result in an increase in Dispatch Balancing Costs.

10.1.8. Forced Outages of Transmission Plant

The forced outage of transmission plant may lead to increased Dispatch Balancing Costs due to resultant generator and/or transmission constraints. The outage of certain key items of the transmission system can potentially increase Dispatch Balancing Costs significantly. For example, if a generator is radially connected to the system and the radial connection is forced out, the impact on Dispatch Balancing Costs 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.

10.1.9. 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.

10.1.10. 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 Bidding Code of Practice is followed. Therefore the role of the market monitor in monitoring the behaviour of participants and acting in a timely manner is important.

10.1.11. 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 Dispatch Balancing Costs 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).

10.1.12. 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 constraints costs.

10.1.13. Modifications to the Trading and Settlement Code

All assumptions made in this submission were based on the current Market Rules as outlined in the latest version of the Trading and Settlement Code (version 10.0). The impact of future rule changes has not been considered, with the exception of the implementation of the revised rules around non-firm Price Taking generation, and must be deemed a potential risk.

10.1.14. Network Reinforcements and Additions

The PLEXOS model was set up with the most up to date data available at the time of the data freeze (February 2012). 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 and unexpected or early generator closures or long-term forced outages.

10.1.15. 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.

10.1.16. SO Interconnector Trades

The use of SO Interconnector Trades on Moyle and EWIC for security of supply is a vital service and a provision for the Low and High Frequency Services has been included in this submission. However, as highlighted in Section 3.5.6, while SO Interconnector trades may be required to maintain system security in exceptional circumstances, due to the unpredictable and infrequent nature of their requirement, no provision is included in this submission. In the event that SO Interconnector trades are required to maintain system security on a prolonged basis, the costs of these trades may be extremely expensive and the impact on Dispatch Balancing Costs can build up to significant levels very quickly, as occurred in 2008.

10.2. Other Risk Factors

While a number of key specific risks have been explicitly identified and outlined in Section 10.1 above, there are many factors that may contribute to unexpected and unforecast increase/decrease in DBC. Examples include significant exchange rate variations, operation of OCGTs 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.

11. Cost Recovery and Financing

Dispatch Balancing Costs will remain 100% pass through, as per the current arrangements. In the event there is a requirement for intra or inter year balancing this will be provided by EirGrid and SONI on 75%:25% basis, in accordance with the Specified Proportions, again as per the current arrangements. The costs of putting in place such facilities, including any arrangement fees, commitment fees and interest on imbalance is separately recoverable. In the event there is a negative imbalance in dispatch balancing costs within the year EirGrid and SONI will notify the SEM Committee when the a negative imbalance equivalent to 50% and again at 75% of the level of standby facility is breached. Should there be an 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 of this will be provided for through the ‘k’ factor in the tariff in the following year (i.e. on a y+1 basis), including interest, as per the current practice.

Appendix 1: PLEXOS Modelling and Assumptions

PLEXOS has been used for a number of years 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

This is the lines, cables and transformers operated by SONI and EirGrid. PLEXOS allows for the addition of new equipment, decommissioning of old equipment and equipment up-ratings.

Generation/Interconnection

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

Demand

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

Fuel Prices

Fuel prices for 2012/13 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters[20] and HEREN[21] reports and information available from the ICE futures website[22]. Carbon costs are also forecast and used, along with fuel costs, to calculate simulated bids for generators and interconnector units in SEM and BETTA. These are then input to PLEXOS to simulate participant commercial offer data for each unit.

Note that the Carbon Price Floor is assumed to take effect in the United Kingdom (therefore including Northern Ireland) on 1st April 2013.

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

General

Feature	Assumptions
Study period	The study period is 1st October 2012 to 30th September 2013.
Data Freeze	The input data for the PLEXOS model was frozen on 29th February 2012.
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. An optimisation time horizon beyond the end of the trading day is used to avoid edge effects between trading days.
Plexos Version	6.201 R31
Model Reference	Unconstrained: DBC 1213 UC v0.15 Constrained: DBC 1213 v0.13

[20] http://thomsonreuters.com/products_services/financial/financial_products/commodities/energy/
[21] http://www.icis.com/heren/
[22] https://www.theice.com/homepage.jhtml

Demand

Feature	Assumptions
Regional Load	Total load for Northern Ireland and non-industrial load for Ireland are represented using individual hourly load profiles for each jurisdiction. Both profiles are at the generated exported level and include transmission and distribution losses and demand to be met by wind and small scale generation. The profile for Ireland is net of industrial load.
Non Industrial 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.
Industrial Demand Data (Ireland)	Industrial loads are generally constant over the day, though some loads change between night and day hours. Rather than following the system demand profile, they are modelled explicitly as purchasers in Plexos with a constant load.
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 as per the All-island Generation Capacity Statement 2012-2021.
Production Costs	Calculated using an estimate of Commercial Offer Data (COD) for each unit. The Commercial Offer Data is based on historical generator bids, a forecast of fuel prices and the Regulatory Authorities' publicly available dataset: 2011-12 Validated SEM Generator Data Parameters Public v1.0. The COD consist of the following for each unit • Price/Quantity pairs • No Load costs • Start-up costs Note that the Carbon Price Floor is assumed to be in place in GB and NI from April 2013 and this has been reflected in bids for generators in those regions.
Generation Constraints (TOD)	Based on the data in the 2011-12 Validated SEM Generator Data Parameters Public v1.0, the following technical characteristics are implemented: • Maximum Capacity • Minimum Stable Generation • Minimum up/down times • Ramp up/down limits Changes to these parameters have been made where necessary to reflect approved Technical Offer Data (TOD) in the SEM market systems.
Scheduled Outages	Draft outage schedules are used for 2012 and 2013 maintenance outages. These include STMOs.
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates and Mean Times to Repair are based on EirGrid/SONI forecasts and RA data.

Feature	Assumptions
Hydro Generation	Hydro units are modelled using daily energy limits. Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled.
Wind Generation	Wind generation resources for Northern Ireland are as per SONI's anticipated connection dates and currently installed wind capacity. For Ireland, the latest target connection dates have been utilised, with adjustments made to expected connection dates
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,290 MWh. The efficiency of the unit is 70%. It is assumed that the units are all operational by start of study period.
Embedded Generation	An aggregate embedded generation profile (non-locational) is used to account for generation which is not explicitly modelled and is offset against the demand, and also any small scale generation which is not modelled explicitly. This includes the DSU which will be operational in the SEM during the study period.
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 are not modelled explicitly (see note above on Embedded Generation). The AGU unit in SEM is 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.
Price-Takers	In the constrained model, price-takers are modelled using negative bids. In the unconstrained model, the peat and Sealrock price takers are subtracted directly from the load to produce the Market Schedule Demand. The hydro units assumed to be price-takers are optimised in the unconstrained schedule and this output input to the constrained model as a fixed profile.
Interconnector Flows	Interconnector trades with Great Britain are determined using price arbitrage. To determine the GB price, the BETTA market was modelled using the Nash-Cournot algorithm built into Plexos. A "Hurdle Rate" was applied to each interconnector to account for factors that would affect the decision of a rational trader – Capacity Payment Mechanism in SEM, Uplift (a feature of modelling in Plexos), GB network charges, and a risk factor to reflect ex-post pricing in SEM. Flows on the Interconnectors calculated in the unconstrained run were used as an input to the constrained run.

Transmission

Feature	Assumptions
Transmission data	The transmission system inputted to the model is based on the Planet FS12 database.
Transmission Constraints	The Transmission system is only represented in the constrained model. The market schedule run is free of Transmission constraints.

Feature	Assumptions
Network Load Flow	A DC linear network model is implemented. The Plexos model has been validated by comparing sample periods with a full AC load flow.
Ratings	Ratings for all transmission plant are based on figures from the Planet database and have been verified by Transmission Network Planning in EirGrid and by SONI.
Tie-Line	The North-South tie-line is not represented in the SEM. The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 300 MW N-S and 200 MW S-N.
Interconnection	The Moyle Interconnector and EWIC are modelled, with losses applied.
Forced Outages	No forced outages are modelled on the transmission network.
Scheduled Outages	Some major transmission outages relating to upgrade works are 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.
Static sources	Static reserve provided by STAR (an interruptible load scheme) and the effect of the Winter Peak Demand Reduction Scheme on the STAR is modelled. An overall maximum limit of 100 MW of static reserve from Interconnection was applied.

