SEM-11-054a
Appendix 1

Transmission System Operators' Submission for Dispatch Balancing Costs October 2011 – September 2012

29th April 2011

V2.0

1. Executive Summary

The Transmission System Operators' (TSOs) forecast of Dispatch Balancing Costs is €143 million in nominal terms for the 12 month period from 1st October 2011 to 30th September 2012. This represents an increase of approximately €32 million on last year's forecast.

The primary driver of this forecast increase in Dispatch Balancing Costs is the rising cost of fuel. Fuel costs have risen significantly over the last 12 months. For the Tariff Year 2011-12 forecast fuel costs represent a significant increase of between 30% and 50% on those forecast in the submission for the previous Tariff Year. While all costs have increased, distillate and oil costs have seen a greater rise, thus widening the gap between gas/coal and oil/distillate fired units. As a result, the cost of constraining-on out-of-merit generation for reserve, transmission and/or system security constraints is greater.

Changes to the generation portfolio due to station closures and forced outages mean that reserve, both spinning and replacement, has to be sourced from other, more expensive and sometimes less-efficient plant. This increases the cost of reserve and is driving higher DBC.

Ongoing monitoring of constraint costs and the drivers behind them is undertaken to ensure that costs which are within the TSOs' control are continually minimised. The TSOs undertake a number of measures to control and/or mitigate the costs of re-dispatching the system.

These measures include, but are not limited to:

- Performance Monitoring of all units according to Grid Code;
- Levying of Other System Charges on generators whose failure to provide necessary services to the system lead to higher Dispatch Balancing Costs i.e. Generator Performance Incentives, Trip Charges and Short Notice Declaration Charges;
- Grid Code modifications around failure to follow Dispatch Instructions e.g. Notice to Synchronise instruction; and
- Ongoing review of dispatch policy.

The charges recovered through Other System Charges during Tariff Years 2009-10 and 2010-11 are expected to be netted off Dispatch Balancing Costs for Tariff Year 2011-12, subject to SEM Committee approval, thus reducing the overall cost of Dispatch Balancing Costs. Other System Charges also provide an incentive for improved generator performance which contributes to minimising dispatch costs.

This forecast of Dispatch Balancing Costs is based on a number of assumptions and expected conditions for the Tariff Year 2011-12. However, the TSOs have also outlined risk factors which relate to low probability events that could have a major impact on Dispatch Balancing Costs for the year were they to occur.

2. TSO Dispatch Balancing Costs Submission

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.

“Dispatch Balancing Costs” (DBC) is a TSO-defined term and refers to the sum of Constraint Payments, Uninstructed Imbalance Payments and Generator Testing Charges. The submission reflects the TSOs’ best estimate of expected expenditure required for Dispatch Balancing Costs over the 12 month period from 1st October 2011 to 30th September 2012 inclusive, referred to as the Tariff Year 2011-12.

The TSOs’ forecast of DBC is €143 million in nominal terms for the Tariff Year 2011-12. A detailed breakdown of the components is contained in Section 6. Where possible, data from the Single Electricity Market (SEM) has been used to inform the forecasting process.

This estimate of DBC 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.

The TSOs are responsible for forecasting and managing DBC. This forecast is used by the Single Electricity Market Operator (SEMO) in the derivation of the Imperfections Charge, which is levied on suppliers by SEMO.

2.1. Overview of Imperfections Charge and Dispatch Balancing Costs

The purpose of the Imperfections Charge is to recover the anticipated net payments to Generator Units in respect of Constraint Payments, Uninstructed Imbalances (less Testing Charges for Generator Units), Make Whole Payments and any net imbalance between Energy Payments and Energy Charges over the Year, with adjustments for previous years as appropriate. The charges recovered through Other System Charges (OSC) are expected to be netted off DBC for the Tariff Year 2011-12, subject to SEM Committee approval. OSC are discussed further in Section 9 of this document.

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

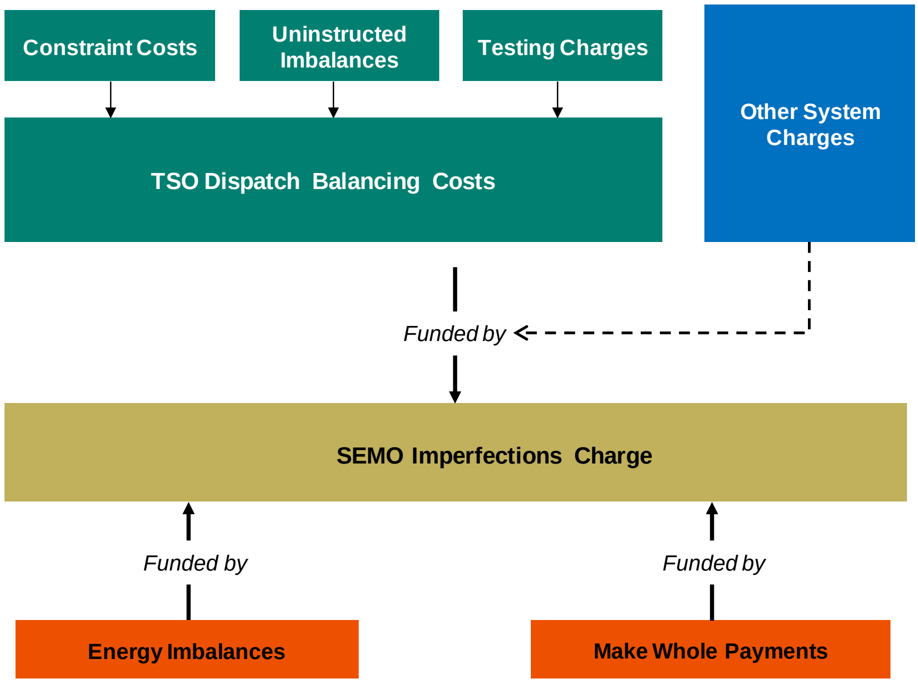

Figure 1 – Relationship between Dispatch Balancing Costs and Imperfections Charge

2.1.1. Dispatch Balancing Costs

- Constraint Costs make up the largest portion of Dispatch Balancing Costs. These costs are based on the market rules as specified in the Trading and Settlement Code and are covered in more detail in Section 3.

- Uninstructed Imbalances[1] and constraint costs are linked, with uninstructed imbalances having a direct effect on constraints costs, as TSOs redispatch generators to counteract them. It is assumed that the costs of uninstructed imbalances (for over and under generation) will, on average, be recovered by the uninstructed imbalance payments for the forecast period and that any net benefit accrued will off-set constraint costs incurred due to remedial action required by TSOs in response to uninstructed imbalances. Therefore, a zero net cost has been provided for this.

- Testing Charges are paid by Generator Units under test as testing imposes additional constraint costs. The testing tariffs have been set at a level that should, on average, recover the additional costs imposed in most circumstances. Therefore, a zero provision has been made for the net contribution of Generator Testing Charges to Dispatch Balancing Costs. A consultation paper on the design and setting of the testing tariffs will be published in Q2 of this year.

The following sections of this submission provide information on Dispatch Balancing Costs, an overview of the Dispatch Balancing Costs forecasting process and details of the key assumptions that formed the basis of the forecast. There are also a number of risk factors which could have a significant impact on the constraint costs and which have not been included in this forecast.

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

3. 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 by the TSOs (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 3.1, below, describes the main categories of issues that can lead to a difference between the market schedule and actual dispatch and hence constraint costs.

3.1. Why Constraint Costs Arise

3.1.1. 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 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.

3.1.2. 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.

3.1.3. 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 generator availabilities. However, as the TSOs do not have this perfect foresight, they must plan and operate the system to account for possible variations in these parameters. For example, if a generator is dispatched to synchronise by the TSO but fails to synchronise or is on-load and subsequently trips, this is 'known' by the market scheduling software and it will take into account the unavailability of this unit in the production of the market schedule. The TSOs, however, will respond to the event in real time by re-dispatching fast-acting generation to maintain system security until the affected generator is available to synchronise onto the system. The market schedule and actual dispatch will therefore differ.

3.1.4. 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.

3.2. Minimising Constraint Costs

Constraint costs will inevitably arise due to the factors described in Section 3.1 above and they are also dependent on a number of underlying conditions. Some of these conditions, such as fuel costs, generator forced outages 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 is taking place on all units to accurately identify 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.
- Levying of 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 9.
- Exploring a number of additional Ancillary Services that would offer improvements to the operational flexibility of the power system and may help to mitigate constraint costs.
- The development of Grid Code modifications around failure to follow Dispatch Instructions e.g. Notice to Synchronise instruction.
- Ongoing review of dispatch policy.

4. DBC Forecast Modelling

4.1. Approach to DBC Forecasting

The modelling of DBC and production of the cost forecast has been a joint process involving both TSOs. 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 DBC that could not be accurately modelled in PLEXOS.

As this is an estimate of DBC 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.

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 8.0, dated 22nd November 2010.
- 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' Dispatch Balancing Costs 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 February 2011.
Forecast period	The forecast period is from 1st October 2011 to 30th September 2012.
Currency	All costs are modelled in euro.
Fuel Prices	Fuel prices for 2011/12 are defined in €/GJ based on the long term fuel forecasts in the HEREN reports and information available from the ICE futures website.

Participant behaviour	It is assumed that generators bid according to their short run marginal costs.
Demand Forecast	The demand is based on the 2011/12 median forecast for both ROI and NI from the All-island Generation Capacity Statement 2011-2020[2].
Generator Schedule Outages	2011 and 2012 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.
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. Enough peaking units are kept offline at all times to account for replacement reserve.
Louth-Tandragee tie-line transmission limits	A flow limitation is modelled for the constrained schedule, which is assumed to be 300MW N-S and 200MW S-N.
Interconnection - Moyle	A fixed Moyle flow file is used, which is representative of level of activity on the interconnector, based on historical flows from 2010.
Interconnection - EWIC	The East-West Interconnector (EWIC) will undertake commissioning testing during the tariff year 2011-12. It is assumed that testing charges will offset any additional constraint costs incurred during commissioning.
Intra-Day Trading	No explicit provision has been made for Intra-Day trading in the PLEXOS model as the TSOs are not in a position, at this stage, to predict its impact on constraints.

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

[2] http://www.eirgrid.com/media/GCS%202011-2020%20as%20published%2022%20Dec.pdf

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 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.

PLEXOS Results

The total cost of the constraints modelled and analysed in the PLEXOS model for Tariff Year 2011-12 is estimated to be approximately €114 million. This PLEXOS model portion of the forecast has increased from the figure of €92.2m forecast for the Tariff Year 2010-11.

The most significant changes in the PLEXOS model from last year are:

- **Fuel prices:** Forecast fuel prices for have increased significantly in comparison to those in the 2010-11 PLEXOS model, due to significant increases in fuel prices in the last 12 months. Forecast gas prices are approximately 35% higher and forecast coal prices increased by approximately 30%. Forecast distillate and oil prices are higher, with distillate prices approximately 40% higher and forecast oil prices 50% higher. These higher forecast prices have a twofold impact on the DBC submission:
  - Constraint costs in general are higher when fuel costs are higher.
  - Due to generation capacity available, the majority of in-merit generation is gas-fired and coal-fired generation. However, the widening gap between forecast gas/coal and forecast oil/distillate prices results in increased constraint costs if the oil/distillate units that are not in merit but need to be constrained on.
- **Generation Updates**: a number of updates to the generation portfolio were reflected in the model, including the addition of the Meath Waste Energy unit and increasing installed capacity of wind generation.
  - By the end of the tariff year 2011-12 it has been assumed that there will be 2,770MW of wind generation installed on the island.
- **Generator Outages:** As in previous years, the scheduled outages of generators are included in the PLEXOS model. This year’s model includes the long-term forced outages of generators including Turlough Hill (for part of the tariff year) and North Wall CCGT.
- **Key operational constraints:** In addition to modelling reserve requirements and transmission overload limits, the PLEXOS model includes a number of key operational constraints. These include constraints required for voltage support in certain areas and system stability.

5. Specific Constraint and Uninstructed Imbalance 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.

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.

5.1.1. Changes to demand and generator availability

Since it is calculated *ex post*, the Unconstrained Unit Commitment (UUC) (initial) market schedule[3] 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. For example, 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. 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). This continuous information asymmetry results in considerable constraint costs over the year.
A provision of €8.1m has been included to take account of changes to demand and generator availability.

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.
A provision of €11.3m has been included to take account of the impact of wind predictability.

[3] In the Trading and Settlement Code, the UUC is referred to as the MSP software.

5.1.3. Long Start-Up and Notice Times

The generation portfolio has changed in recent years due to closures of mid-merit plant such as Poolbeg Units 1 and 2, and the long-term forced outages of a number of other mid-merit and flexible generation units, such as North Wall 4 and Turlough Hill. In addition, transmission constraints limit output from Aghada Unit 1 and the Aghada Gas Turbines at times, further limiting the available generation portfolio. 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 these 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 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. Operators are required to call units with long notice periods further from real time when there is greater uncertainty about forecast accuracy, thus increasing 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 generator availability or forecast demand or wind. Availability of generation with shorter notice times would mean that such commitment decisions could be made nearer to real-time and with better information.

A provision of €3.8m has been included to account for divergence of dispatch from the optimal solution due to generation portfolio changes. The return of Turlough Hill is expected to have a positive impact on the flexibility of the generation portfolio and the return of these generator units has been incorporated in the provision.

5.1.4. Moyle schedule set D-1

The ex-ante market schedule is set D-1 and provides generators with indicative running regimes. However, in the case of the interconnector users, the ex-ante market schedule determines the dispatch quantities. The initial ex-post UUC market schedule, with the benefit of perfect foresight on D+4, at times determines a different schedule for interconnector units to the ex-ante market schedule. Any differences between these schedules will act to increase constraint costs. The impact of this on constraint costs will depend on the interaction of a number of factors – differences between SMP in ex-ante and ex-post schedules, aggregate Moyle supply curve, and the generation supply curve. This year’s provision is calculated based on an estimate of the constraint costs incurred due to changes between the ex-ante and the ex-post market schedules for the Moyle Interconnector for tariff year 2011-12 and is based on historical data from 2009.

A provision of €0.5m has been included to take account of constraints costs arising from setting the Moyle dispatch on D-1.

5.2. Specific Transmission System Constraints

Transmission line limits are modelled in PLEXOS. 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:

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 date (February 2011).
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.

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.

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.
A provision of €1.6m is included to account for the reduction in operational efficiency due to dispatch in minimum generation mode for reserve. This provision takes into account the planned return of the station from outage in the tariff year 2011-12.

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.

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 of approximately €0.7m 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.

5.4.2. Hydroelectric generator constraints

There are a number of special limitations that apply to hydroelectric generators that are not modelled in the UUC market schedule. For example, a drawdown restriction requires gradual, sequential loading and unloading of the sets in a hydroelectric station. This type of restriction means that, in practice, the limited hydroelectric energy cannot always be used at the most economic times, resulting in an increase in constraint costs. Other limitations on optimal hydroelectric running include reservoir coupling (unit output dependent on the output of an upstream unit), environmental restrictions (e.g. fish spawning) and plant shutdown due to external factors. However, from time to time the UUC does not fully utilise the daily energy limit of the hydroelectric generation, but the TSOs will dispatch this energy, resulting in a decrease in constraint costs. As such, the constraint costs of less economic dispatch by the TSOs are somewhat offset by this and the overall cost is reduced.

Taking this into account, a zero provision has been included in the submission for hydroelectric generation. However, if changes are made to the UUC or there is a Modification to the Trading and Settlement Code which results in the UUC always fully utilising the daily energy limits of hydro plant, the special limitations described above may result in increased constraint costs and a specific provision may be required.

5.5. Capacity Tests for System Security and 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 of €2.4m 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.

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 Interconnector. 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 typically 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 now also in service. This service automatically exports power to the other System Operator whenever the frequency increases above certain predefined limits.

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 is specified by National Grid and can be very variable. An explicit provision for constraints costs arising from SO Interconnector Trades of €0.15m 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.

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.

6. Uninstructed Imbalances and Testing Charges

As described in Section 2, the other components of DBC, in addition to Constraint Payments, are Uninstructed Imbalances and Testing Charges.

6.1. Uninstructed Imbalances

Uninstructed imbalances (positive or negative) have a direct effect on constraints costs, as TSOs redispatch generators to counteract the effect of the uninstructed imbalances on the system. It is assumed that the 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 to date 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 such, a zero provision for Uninstructed Imbalances is included in the submission and consequently no provision for the related constraint costs.

6.2. Testing of Units

Testing of units requires out of merit running which increases constraint costs. The testing charges are assumed to cover this net increase in costs and no extra provision is made in this submission. A consultation paper on the design and setting of the testing tariffs will be published by the TSOs in Q2 of 2011.

6.2.1. Within-day testing

Within-day testing[4] involves uninstructed imbalance payments for the out-of-merit running necessitated by the test, which are assumed to be sufficient to cover any additional constraint costs incurred due to this testing. Therefore, a zero provision is made. In addition, the modification on Generator Unit Short Term Test Status (Mod 65_08) has been recommended for approval by the Modifications Committee and if approved by the SEM Committee will result in a significant reduction in uninstructed imbalances associated with within-day testing.

[4] A **Within-Day Test** is defined in the Grid Code (v3.5) as: An Operational Test with a total duration of less than 6 hours in any Trading Day, where the Active Energy produced during the total duration of the test is less than: (i) 3 times the Active Energy which would be produced by the Test Proposer's Plant during 1 hour of operation at the Plant's Registered Capacity; and (ii) 500 MWh.

7. Summary of Dispatch Balancing Costs

The forecast for Dispatch Balancing Costs consists of the PLEXOS estimate for constraints, with all of the factors as outlined modelled, plus the specific external factors that it was not possible to model in PLEXOS. These have all been outlined in the previous sections and the results are summarised as in the table below.

Description		Forecast (€m)
PLEXOS Modelled Constraints for 12 Months		**114.0**
Perfect Foresight Effects	**Changes to demand and generator availability**	**8.1**
	Wind predictability	**11.3**
	Long Start-Up and Notice Times	**3.8**
	Moyle schedule set D-1	**0.5**
Specific Reserve Constraints	**Turlough Hill**	**1.6**
Market Modelling Assumptions	**Block Loading**	**0.7**
	Hydro limitations & issues	**0.0**
System Security constraints	**Capacity Testing & Performance Monitoring**	**2.4**
System Operator Interconnector Trades		**0.2**
Total Forecast 2011-12		**142.6**

8. Risk Factors

8.1. Key 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 Dispatch Balancing Costs forecast but could potentially result in a significant deviation from this constraint forecast if they arose.

8.1.1. 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.

8.1.2. 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 2011. 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.

8.1.3. 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. This risk is magnified by the divergence of fuel prices described in Section 4

8.1.4. 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. The continued long-term outages of the Turlough Hill units during the tariff year 2011-12 are anticipated to result in increases to Dispatch Balancing Costs for the duration of these outages. As such, any overrun of these outages and a consequent delay in the planned return dates of the units would result in considerably higher Dispatch Balancing Costs.

8.1.5. 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.

8.1.6. 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. However, until such identification SEMO would be required to pay out the associated cost until directed otherwise.

8.1.7. 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. Therefore the role of the market monitor in monitoring the behaviour of participants and acting in a timely manner is important.

8.1.8. 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).

8.1.9. 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.

8.1.10. 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 8.0). The impact of future rule changes has not been considered and must be deemed a potential risk.

8.1.11. 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 2011). 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.

8.1.12. 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.

8.1.13. SO Interconnector Trades

The use of SO Interconnector Trades on Moyle 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 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, 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.

9. 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 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.

The SEM Committee decision paper, “Harmonised All-Island Ancillary Services Rates and Other System Charges” (SEM-10-001) stated the following in relation to netting Other System Charges from Dispatch Balancing Costs (DBC) when calculating the Imperfections Charge:

“In the case of the other charges (i.e. Trips, SNDs and GPIs), the TUoS statement of charges will be used as a facilitating vehicle to impose and publish the charges annually. It is appropriate to net off these charges from the DBC. The DBC are partially incurred by generators having poor performance and behaviour. They are recovered in the SEM through an imperfections tariff levied on suppliers by the Single Electricity Market Operator (SEMO), which in turn is regulated by the RAs. For the avoidance of doubt the non-AS charges reduce the imperfections tariff and not the DBC themselves.”

A modification proposal, Mod 13_11: “Inclusion of Other Systems Charges in the Imperfections Charge”, to insert the necessary terms into the Trading and Settlement Code to allow for this netting process to occur was raised. This modification was recommended for Approval by the Modifications Committee on 5th April 2011. In this submission, it is assumed that this modification will be approved by the SEM Committee and that an estimate of OSC to September 2011 will be netted off DBC for the Tariff Year 2011/12. The TSOs published a consultation paper on OSC on 18th April 2011[5]

Following the proposed modification above, this is the first tariff year where OSC will be netted off DBC. As the TSOs have collected OSC since implementation in February 2010, OSC for both tariff years 2009/2010 and 2010/2011 will be included. The TSOs estimate that OSC up to the end of September 2011 will total €12 million. This estimate includes a projection for the rest of the tariff year 2010/2011 and may be revised as better information becomes available. Please note that where derogations have been approved to date, the effect on OSC has been captured. However, no pending derogations have been taken into account in the development of this estimate.

[5] http://www.eirgrid.com/operations/ancillaryservices/consultationsworkshops/

10. 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 recoverable through the EirGrid and SONI TSO controls. 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) as per the current practice.

Appendix 1: PLEXOS Modelling and Assumptions

PLEXOS has been used for a number of years by the TSOs. 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. By varying the data that PLEXOS considers, the impact on the generation schedule, and hence production cost, can be assessed. 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

The prices of the various fuels used by the generators (gas, oil, coal and distillate) are modelled and these vary over the study horizon. Fuel prices are based on the long term fuel forecasts in the HEREN reports and information available from the ICE futures website.

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

General

Feature	Assumptions
Study period	The study period is 1st October 2011 to 30th September 2012.
Data Freeze	The input data for the PLEXOS model was frozen at February 2011.
Currency	All costs are modelled in euro.
Participant behaviour	It is assumed that generators bid according to their short run marginal costs.
Generation Dispatch	Two hourly generation schedules: 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 of 30 hourly trading periods is used to avoid edge effects between trading days.
Plexos Version	6.201 R19.

Intra-Day Trading	No explicit provision has been made for Intra-Day trading in the PLEXOS model as the TSOs are not in a position, at this stage, to predict its impact on constraints.

Generation

Feature	Assumptions
Generation Resources	Conventional generation resources are as per the All-island Generation Capacity Statement 2011-2020, with some adjustments made to take account of announcements made since the data freeze for that publication took place. All such changes are noted in this document.
Production Costs	Calculated using the Regulatory Authorities' publicly available dataset: 2010-11 Validated SEM Generator Data Parameters Public v1.0. Certain changes have been made to this dataset where necessary. • Fuel cost (€/GJ) – forecasted for 2011 and 2012. • Piecewise linear heat rates (GJ/MWh) • No Load rate (GJ/h) • Warm start energies (GJ) • Cold start energies (GJ) • Fixed element of start up costs – based on analysis of commercial offer data.
Generation Constraints (TOD)	Based on the data in the 2010-11 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 submitted TOD.
Scheduled Outages	2011 and 2012 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. These include STMOs.
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Several sets of Forced Outages are generated randomly and the likelihood of each set of forced outages is assessed by comparing how statistically similar it is to the other sets. Forced Outage Rates and Mean Times to Repair are based on historical data.
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 are as per SONI and EirGrid's anticipated connection dates and currently installed wind capacity.

Feature	Assumptions
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,290 MWh. The efficiency of the unit is 70%. The model assumes the units return on a staggered basis from the end of 2011.
Embedded Generation	An aggregate embedded generation profile (non-locational) is used to account for embedded generation which is not explicitly modelled and is offset against the demand. The NI load profile does not include demand to be met by small-scale generation (SSG). In order to model the SSG in RoI a regional generation profile is used to represent the aggregate generation from SSG.
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.
Multi-Fuel Modelling	Only one fuel is modelled for each generating unit.
Moyle Flows	A fixed Moyle flow file is used, which is representative of level of activity on the interconnector, based on historical flows from 2010.

Ancillary Services

Feature	Assumptions
Operating reserve	Primary, secondary and tertiary 1 and 2 reserve requirements are modelled. Enough peaking units are kept offline at all times to account for replacement reserve.
Reserve characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.
Reserve sharing	Minimum reserve requirements in each jurisdiction with the remainder being shared. These requirements are per the latest reserve policy.
Static sources	Static reserve provided by STAR (an interruptible load scheme) and the effect of WPDRS on the STAR is modelled. The Moyle interconnector provides 75 MW reserve at night and 50MW reserve during the day.

Transmission

Feature	Assumptions
Transmission data	The transmission system inputted to the model is based on the Planet FS11 database.
Transmission Constraints	The Transmission system is only represented in the dispatch schedule. 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 comparison of sample periods with a full AC load flow, carried out by Technology and Standards.
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. It is still necessary to model a flow limitation for the constrained schedule, which is assumed to be 300MW N-S and 200MW S-N.
Interconnection	Moyle is modelled using a fixed profile, based on historical flows from 2010. The East-West Interconnector is due to begin commissioning during the study period. It is assumed that testing charges will offset any additional constraint costs incurred during commissioning.
N-1 contingency analysis	Principal N-1 contingencies, based on TSO operational experience, are modelled.
Scheduled outages	A number of significant scheduled transmission outages are modelled.
Forced Outages	No forced outages are modelled on the transmission network.

Demand

Feature	Assumptions
Demand	The demand is based on the 2011/12 median forecast for both ROI and NI from the All-island Generation Capacity Statement 2011-2020.
Regional Load	NI total load and RoI non-industrial load is 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 RoI profile 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. As a result the load at every network location will have the same hourly profile as the system demand.
Industrial Demand Data (RoI)	Industrial loads are generally constant over the day. 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.