Commission for Energy Regulation
An Coimisiún um Rialáil Fuinnimh

Utility Regulator
ELECTRICITY GAS WATER

Imperfections Charges

For

October 2010 – September 2011

Consultation Paper

SEM-10-041

30 June 2010

1 EXECUTIVE SUMMARY

This consultation paper presents for the views of market participants the proposed Imperfection Charges for October 2010 to September 2011. It combines the forecast Dispatch Balancing Costs as detailed in the Transmission System Operators' Submission of 30 April 2010 (Appendix 1) with estimates for Make Whole Payments and Energy Imbalance Charges (assumed to be zero) with forecasted Demand figures for 2010/11 to produce the overall Imperfections Charge.

Comments are invited from the industry and the public by 28 July 2010 as detailed in section 4.

2 INTRODUCTION

2.1 THE SINGLE ELECTRICITY MARKET

The Northern Ireland and Ireland Governments together with the energy regulators - the Northern Ireland Authority for Utility Regulation and the Commission for Energy Regulation ("the RAs") - and industry, worked together to create an All-Island Energy Market. The first step in this process was the implementation of an All-Island wholesale electricity market. The Single Electricity Market (SEM) was completed on 1st November 2007 when the market went live.

The SEM is a centralised or gross mandatory pool market, with electricity being bought and sold through the pool under a market clearing mechanism. Generators receive the System Marginal Price (SMP) for their scheduled dispatch quantities, capacity payments for their actual availability, and constraint payments for changes in the market schedule due to system constraints and other, specific factors. Suppliers purchasing energy from the pool will pay the SMP for each trading period, capacity costs, and system support charges. The SEM market rules are set out in the Trading and Settlement Code (TSC). The SEM is governed by the SEM Committee which was set up by both governments and has representatives from both Regulators plus an Independent Member. The SEM is operated by the Single Electricity Market Operator (SEMO) which is a contractual joint venture between the Transmission System Operators (TSOs), Eirgrid and SONI. SEMO's allowed revenues are set by the SEM Committee.

2.2 IMPERFECTIONS CHARGE & DISPATCH BALANCING COSTS

In addition to SEMO's operational costs, the MO tariffs have to recover Imperfections Charges which are made up of Make Whole Payments, Energy Imbalance Charges and Dispatch Balancing Costs. The TSOs submitted a paper to the RAs on 30 April 2010 detailing the costs relating to Dispatch Balancing Costs. Dispatch Balancing Cost is a TSO-defined term and refers to the sum of Constraint Payments, Uninstructed Imbalance Payments and Generator Testing Charges. The details relating to these are covered in Section 3 of this Consultation Paper. Note that the Imperfections Charges are made only on Suppliers while the MO Charges are made on Suppliers and on Generators.

2.3 OBJECTIVE OF PAPER

The objective of this consultation paper is to solicit comments from interested parties on a range of proposals associated with Imperfections Charges and in particular Dispatch Balancing Costs.

3 IMPERFECTIONS CHARGE

3.1 OVERVIEW

The costs associated with Imperfection Charges are depicted in Figure 1 in Appendix 1. Three of the costs covering constraint costs, uninstructed imbalance costs and testing charges (collectively known as Dispatch Balancing Costs) are provided by the System Operators, Eirgrid and SONI. In addition to these, there are also Energy Imbalances and Make Whole payments. The budget required for these two costs is provided by SEMO.

The Transmission System Operators (TSOs) submission was prepared jointly by the Eirgrid and SONI, and captured an all-island estimate of constraint costs, uninstructed imbalance costs and testing charges, collectively known as Dispatch Balancing Costs. The forecast of Dispatch Balancing Costs is for the period from 1 October 2010 to 30 September 2011.

All these costs are estimated *ex-ante* and recovered from Suppliers on a MWh basis through the Imperfections Charge.

3.2 DISPATCH BALANCING COSTS

See Appendix 1. The budget proposed by the TSOs for the tariff year 2010 – 2011 is €110.5M compared to €106M for the tariff year 2009 – 2010. The TSOs have noted that, as improvements to the modelling process are made each year (for example the incorporation of transmission outages in Plexos), a line by line breakdown of the total dispatch balancing costs may be confusing, as direct comparison between a number of the individual cost components is not appropriate. The main focus should be on the total figure.

3.3 ENERGY IMBALANCES

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. Therefore, a zero net cost has been provided for this.

3.4 MAKE WHOLE PAYMENTS

For the previous 12 months Make Whole Payments amounted to €322,369 i.e. 12 months to 31 September 2009. The proposed provision for Make Whole payments is €330,000.

3.5 RECOVERY OF IMPERFECTION COSTS

As stated previously, the dispatch balancing costs are estimated *ex-ante* and this estimate is recovered during the relevant tariff period through the imperfections charge.

However, it is almost certain that differences between the costs being recovered and paid out will lead to instances where SEMO will:

- require working capital to fund constraints payments that exceed revenue collected through the imperfections charge, or,
- have collected revenue through the imperfections charge that exceeds the amount being paid out on constraints.

To allow for the first scenario, the mechanism adopted for previous SEMO Revenues and Tariffs was that the funding required to cover fluctuations during the tariff period, and any allowed under-recovery of revenue during the tariff period will be paid to SEMO in the subsequent tariff period(s) with the appropriate amount of interest This reflects the cost of short-term financing required to provide SEMO’s working capital needs.

Similarly, for situations where the revenue recovered by SEMO through the Imperfections Charge is greater than that paid out in constraints (second scenario above), the Imperfections Charge in the following tariff period(s) will be reduced by an appropriate amount to reflect the allowed over-recovery and the associated interest.

The “K Factor” to be applied to the Imperfections Charge for 2010 – 2011 is €2,672,702. See Appendix 2.

It is proposed that this mechanism is continued in the new Tariff period.

PROPOSALS

The RAs propose that the full estimate provided for the net nominal value of Dispatch Balancing Costs, that is **€110.5 Million**, be recovered through the Imperfections Charge during the new tariff period.

The RAs propose that an amount of **€330,000** be recovered through the Imperfections Charge during the new tariff period for Make Whole Payments.

The RAs propose that the existing treatment of K Factor for over and under recovery of Imperfections costs be continued in the new tariff period.

3.6 IMPERFECTIONS CHARGE

The TSOs have submitted a paper proposing that the full estimate provided for the net value of Dispatch Balancing Costs, that is €110.5 Million, be recovered through the imperfections charge during the new tariff period. The amount allowed will be subject to review and determination ex-post, with allowed under or over-recoveries feeding into the subsequent tariff period(s). Adding €330,000 for Make Whole Payments and subtracting the K Factor of €2,672,702 gives a total Imperfections Charge for 2010 – 2011 of €108,157,298.

Using the Forecasted Demand Figures for 2010 (34,430GWh) and the total Imperfections Charge above, the resulting Imperfections Charge is €3.141 per MWh. (The figure for 2009 -2010 was €2.752 per MWh)

4 PROVISION OF COMMENTS

The RAs request comments on the proposals set out in this consultation paper. All comments received will be published, unless the author specifically requests otherwise. Accordingly, respondents should submit any sections that they do not wish to be published in an appendix that is clearly marked “confidential”.

Comments on this paper should be forwarded, in electronic form, to Billy Walker at Billy.Walker@niaur.gov.uk by 12:00 on Wednesday 28 July 2010.

APPENDIX I

Transmission System Operators' Submission for Dispatch Balancing Costs
October 2010 – September 2011

DOCUMENT DISCLAIMER

1. Introduction

"Dispatch Balancing Costs" 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 2010 to 30th September 2011 inclusive.

The TSOs are responsible for forecasting and managing Dispatch Balancing Costs. 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.

The Imperfections Charge recovers the net cost of Constraint Payments, Uninstructed Imbalances, Testing Charges, energy imbalances and Make Whole Payments (see Trading and Settlement Code clause 4.155 for more information). The diagram below illustrates how these are related; the Dispatch Balancing Cost forecast is used, along with estimates for Make Whole Payments and energy imbalances, to derive the SEMO Imperfections Charge.

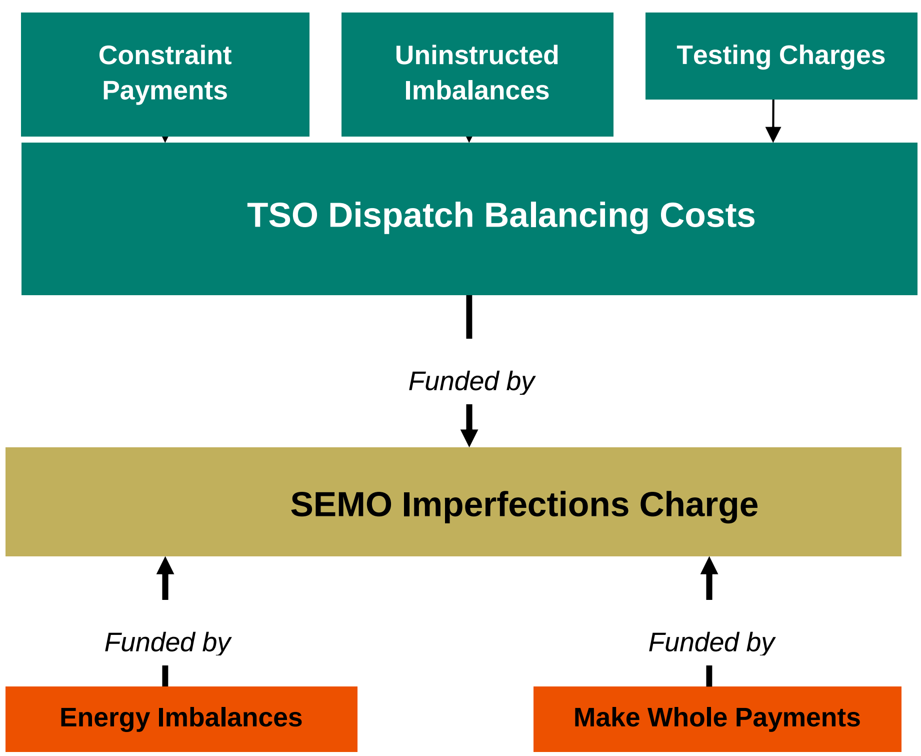

Figure 1 – Relationship between Dispatch Balancing Costs Budget and Imperfections Charge

The TSOs' forecast of Dispatch Balancing Costs is €110.5 million in nominal terms for the 12 month period from 1st October 2010 to 30th September 2011. A detailed breakdown of the components is contained in section 5. Where possible, data from the Single Electricity Market (SEM) has been used to inform the forecasting process.

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

- Where reference is made to the Trading and Settlement Code (T&SC), the version referred to is version 6.1, dated 29th January 2010.
- For the purpose of this submission all monies 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 sections provide some general background 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.

2. Background Information on Dispatch Balancing Costs

2.1 Constraints Costs

Constraint costs are the largest portion of the Dispatch Balancing Costs. 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 to run 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. The remainder of this section describes the main categories of issues that can lead to a difference between the market schedule and actual dispatch and hence constraint costs.

2.1.1 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. The North South tie-line, which is treated as a transmission line in the SEM, may also have a significant effect on the actual dispatch of generating units, due to the flow limitations between the two TSO jurisdictions.

2.1.2 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 such tripping events. To maintain the demand-supply balance, some generators will be constrained down while others will be constrained on/up, again leading to the actual dispatch deviating from the market schedule, which does not account for reserve requirements.

2.1.3 Perfect Foresight

The market schedule of generation, which is used for settlement, is produced after real time (*ex post*) by the market software using known actual demand, 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, 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.

2.1.4 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 actual dispatch, the TSOs (and generators) are bound by these technical realities and so the market schedule and actual dispatch will differ.

2.2 Testing Charges and Uninstructed Imbalances

Generators under test impose 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 later this year.

Uninstructed Imbalances and constraint costs are linked, with uninstructed imbalances having a direct effect on constraints costs, as TSOs redispatch generators to counteract uninstructed imbalances. 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.

2.3 Modelling

The modelling of Dispatch Balancing Costs 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 captured most of the key transmission and reserve constraints. Supplementary modelling was then used to examine factors affecting Dispatch Balancing Costs that could not be accurately modelled in PLEXOS.

As this is an estimate of Dispatch Balancing Costs approximately a year ahead, the assumptions that are made are critical to the forecast. Where possible, data from the SEM has been used to review key assumptions.

In the sections below, details of the PLEXOS model, the key assumptions and the analysis of specific effects on Dispatch Balancing Costs are presented.

3. PLEXOS modelling

PLEXOS is both a costing and pricing model and has the SEM pricing mechanism implemented in it. It can be used to forecast the 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 in this timeframe.

The 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. It also 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.

By performing multiple runs of a PLEXOS model, adding in reserve requirements and transmission system constraints, the effect in terms of increases in total production costs can be analysed. The difference in production costs between these simulations represents the constraint costs associated with the modelled transmission and reserve constraints (as generators are assumed to bid in short run marginal costs).

The total cost of the constraints modelled and analysed in the PLEXOS system is estimated to be €92.2m. This PLEXOS model portion of the forecast has increased from €70.5m last year. The most significant changes in the PLEXOS model from last year are:

- Improved modelling: PLEXOS includes a number of constraints that were either previously modelled explicitly outside of PLEXOS (for example scheduled transmission outages and wind dispatch for system security) or were not included previously (for example negative regulation requirements). These constraints have been incorporated into PLEXOS in an attempt to more accurately model how constraints costs arise in the operation of the power system.
- Fuel prices: Forecast fuel prices for both gas and coal are lower than last year’s forecast prices, with forecast gas prices approximately 25% lower and forecast coal prices reduced by approximately a third. Forecast distillate and oil prices are higher, with distillate prices approximately 20% higher and forecast oil prices up to 60% higher. These forecast prices have a twofold impact on the DBC submission:
    - Due to generation capacity available, the majority of in-merit generation is gas-fired and coal-fired generation, reducing the overall forecast production costs for the year.

    - However, the widening gap between forecast gas/coal and forecast oil/distillate prices results in significantly increased constraint costs if the oil/distillate units are not in merit but need to be constrained on.
- Carbon prices: In addition to the drop in forecast gas and coal prices, the forecast carbon costs have also reduced by approximately 50%.
- Generation changes: The most notable generation changes in the model are that the two combined cycle gas turbines in the Cork area, Aghada unit 2 and Whitegate, are both fully operational for the entire study period, the level of installed wind generation capacity has increased to approximately 2,400 MW and the Sealrock units are now modelled as price takers.
- Forecast demand: the forecast demand for EirGrid used in last year's model was the 2009/10 median forecast from the 2009-2015 GAR. The SONI load profile was taken from the 2009/10 medium demand forecast from the 2009-2015 Seven Year Generation Capacity Statement. The data freeze date for these documents was September 2008. In this year's model, the forecast demand is taken from the 2010-2016 GAR and the 2010-2016 Seven Year Generation Capacity Statement. On average, the forecast system demand is approximately 4.6% lower than last year's forecast.
- Scheduled Generator Outages: As in previous years, the scheduled outages of generators are included in the PLEXOS model. These scheduled outages differ from year to year and this will have an effect on the constraint cost output of the PLEXOS model.
- 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. In this year's model several constraints have been amended due to evolving system conditions. In addition, supplementary constraints have been included for the duration of key outages.

3.1 Key Assumptions

The following table highlights the key assumptions used in the production of the constraints in PLEXOS for the TSOs' Dispatch Balancing Costs forecast.

Subject	Assumption
Data Freeze	The input data for the PLEXOS model was frozen in January 2010.
Forecast period	The forecast period is from 1st October 2010 to 30th September 2011.
Currency	All costs are modelled in euro.
Fuel Prices	Fuel prices for 2010/11 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 EirGrid load profile is the 2010/11 median forecast from the 2010-2016 GAR and the SONI load profile is taken from the 2010-2016 Seven Year Generation Capacity Statement.
Generator Schedule Outages	2010 and 2011 maintenance outages are based on provisional outage schedules.
Generator Forced Outage probabilities	Forced Outage Rates and Mean Times to Repair are based on publicly available data.
N-1 contingency analysis	Principal N-1 contingencies are modelled.
Transmission scheduled and forced outages	A number of significant scheduled transmission outages are modelled in PLEXOS. Forced transmission outages are not modelled.
Interconnection	A fixed Moyle flow file is used, based on flows from 2009.

4. Specific Constraints 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;
- other factors.

4.1 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. The main drivers of these differences include changes to demand and generator availability, changes in expected wind generation due to wind variability and forecastability and also deviations between the ex-ante and ex-post schedules for Interconnector users.

4.2 Specific Transmission System Constraints

Certain transmission line limits are modelled in PLEXOS. However, there are some other transmission system constraints which it is not possible to model in PLEXOS and for which specific provision has to be made. These include outages that were not available prior to the data freeze date for the model and also where scheduled outages of radial feeders result in constraints.

4.3 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 critical source of spinning reserve. However, while reserve provision by Turlough Hill 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 actual dispatch. This energy must be replaced (by the marginal plant), resulting in additional constraint costs over the day.

4.4 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. For example, block loading in the MSP Software assumes that, when synchronising, a generator can reach minimum load within 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. The consequence is that additional constraint costs will arise.

4.5 Other Factors

There are a number of other factors that also impact on constraint costs. These include Capacity Tests for System Security where, 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. Testing the capacity of low merit generators from time to time will necessitate constraining them on, resulting in an increase in constraint costs.

In addition, there will be a net cost on constraints that arises when SO Interconnector Trades on the Interconnector occur, as permitted under the Trading and Settlement Code.

5. Summary of Dispatch Balancing Costs Forecast

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. Due to the improvements in the PLEXOS model, as referred to in Section 3, direct comparison between a number of the individual cost components below is not appropriate.

Description		Forecast 2010/11 (€m)	*Forecast 2009-10 (€m)*
PLEXOS Modelled Constraints for 12 Months		**92.2**	*70.5*
Perfect Foresight Effects	**Changes to demand and generator availability**	**6.0**	*8.8*
	Wind variability and forecastability	**6.0**	*6.2*
	Moyle schedule set D-1	**0.7**	*0.2*
Specific Transmission Constraints	**Limited transmission scheduled outages in PLEXOS**	**0.2**	*3.7*
	Scheduled outages of radially connected generation	**0.9**	*0.8*
Specific Reserve Constraints	**Turlough Hill**	**2.2**	*3.0*
Market Modelling Assumptions	**Block Loading**	**0.7**	*1.1*
	Hydro limitations & issues	**0.0**	*0.5*
Other Factors	**Capacity Testing**	**1.4**	*2.5*
	SO Interconnector Trades	**0.1**	*5.6*
	Wind Dispatch and System Security	**0.0**	*3.0*
Total Forecast 2010		**110.5**	*106.0*

6. Risks

There are a number of risk factors that could have a significant impact on the level of Dispatch Balancing Costs. 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. Key risks include High Impact Low Probability events (HILPs) such as unplanned outages of critical transmission and/or generation plant, significant fuel price variations and modifications to the Trading and Settlement Code. While no provision has been made for these risks in the DBC forecast submission, the TSOs understand that DBC will continue to be treated on a pass through basis as in previous years.

APPENDIX II IMPERFECTIONS K FACTOR

RECOVERY MECHANISM

In the 2007/2008 and 2008/2009 Revenue Determinations an annual amount was allowed in respect of Energy Imbalances. In the case of 2007/2008 this was included within the SEMO Tariff but in 2008/2009 the recovery mechanism was changed over to recovery via the Imperfections Tariff.

The 2007/2008 Ex Post Review resulted in a positive Imperfections K factor of €3.68m from a combination of (a) the variance between Imperfections receipts and Constraint payments and (b) the Energy Imbalance (arising from a difference in Energy receipts and payments).

PART ADVANCEMENT OF 2010/2011 K FACTOR

Separately, at the time of the 2009/2010 Revenue and Tariff Determination a large overrecovery in the 2008/2009 Imperfections had accumulated at that point. Normally the k factor for 2008/2009 would be applied to the 2010/2011 Tariff year but given the size of the overrecovery at that point, SEMO proposed an advancement of the k factor. As a result €8.9m was reduced from the 2009/2010 Imperfections Tariff. Together with the normal timing 2007/2008 k factor of €3.68m this gave an overall k factor of €12.58m which was applied to the 2009/2010 Imperfections Tariff.

2009/2010 ENERGY & IMPERFECTIONS IMBALANCE

As mentioned above, it was anticipated at the time of the 2009/2010 Revenue Determinations that there would be a significant overrecovery on Energy/Imperfections for 2008/2009. The final figures are as follows:

- Energy Imbalance for 2008/2009 was an overrecovery amount of €6.44m.
- Imperfections Imbalance for 2008/2009 was an overrecovery amount of €5.97m.

MARKET IMBALANCES

Receipts and Payments on market activity include not only energy and imperfections but capacity and foreign exchange gains/losses in relation to energy, imperfections and capacity. Imbalances can also arise on capacity receipts/payments, foreign exchange elements and market interest received/paid. These related imbalances are not recovered via the SEMO tariff and to date have not been recovered via the Imperfections tariff either. As a result the Imperfections k factor mechanism should include these additional market imbalances:

- The imbalance for Capacity for 2008/2009 was an overrecovery of €1.37m.
- The imbalance on the foreign exchange market elements was an underrecovery amount of €1.14m.
- The imbalance for market interest received/paid was €0.04m underrecovery for 2008/2009.

The respective market imbalances for 2007/2008 that were not included in the 2007/2008 k factor calculations are as follows:

- €0.02m Capacity underrecovery
- €0.11m Market Interest overrecovery
- €1.17m foreign exchange elements underrecovery
-

SUMMARY POSITION

The summary position of all the market imbalances discussed above is as shown in the following table.

	Over/(Under) Recovery
Imperfections K factor from 2008/2009	**€**
Total Market Imbalance 2008/2009	12,606,759
Less K factor advanced in 2009/2010	(8,900,000)
	3,706,759
Imperfections K factor adjustment from 2007/2008	
Total Market Imbalance 2007/2008	2,599,881
Less K factor already applied in 2009/2010	(3,678,938)
Remaining K factor to be applied to 2010/2011	(1,079,057)
Total Imperfections K factor to be applied 2010/2011	**2,627,702**

Table A: K factors to be applied to 2010/2011 Imperfections Tariffs

<u>The Imperfections K factor is an overrecovery amount of €2.63m which will reduce the 2010/2011 Imperfections Tariff.</u>