Imperfections Charge

October 2017 – September 2018

And

Incentive Outturn

October 2015 – September 2016

Consultation Paper

SEM-17-045

5 July 2017

CONTENTS

1 EXECUTIVE SUMMARY

The Single Electricity Market (SEM) Imperfections Charge is made up of a number of components, the largest of which relates to Dispatch Balancing Costs (DBC). The purpose of the Imperfections Charge is to recover the anticipated DBC (less Other System Charges), Make Whole Payments and any net imbalance between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges, over the tariff year. The K factor adjustment mechanism enables any under or over recovery of Imperfections Costs, in the previous year and an estimate for the current year, to be accounted for in the following tariff year.

Eirgrid and SONI, together the Transmission System Operators (TSOs), have prepared and submitted the:

1. 'Forecast Imperfections Revenue Requirement for Tariff Year 1st October 2017 to 30th September 2018'[1] (2017/18 Forecast); and
2. 'Imperfections Costs Incentive for Tariff Year 1st October 2015 to 30th September 2016'[2] (2015/16 Incentive Outturn).

The Utility Regulator (UR), in Northern Ireland, and the Commission for Energy Regulation (CER), in the Republic of Ireland, together the Regulatory Authorities (RAs), have analysed both submissions and the models underpinning them. This paper details the RAs proposals in relation to each submission.

1.1 2017/18 FORECAST

The TSOs have forecast an Imperfections revenue requirement of €213.6 million for the 2017/18 tariff year. This represents a 45% increase from the €146.8 million forecast for the 2016/17 tariff year. The RAs have reviewed this forecast and proposed an overall revenue requirement of €183.28m which now represents a 25% increase from the 2016/17 tariff year.

The forecast provided by the TSOs included a number of new items for consideration for 2017/18 which are discussed in the TSO submission. The RAs have recommended that specific amendments are made to the new items, which are:-

- Interconnector Ramp Rate Disparity forecast, €10.8m – having liaised with the TSO on the evolving issue of interconnector ramping and the interaction with balancing markets the

[1] Appendix 1
[2] Appendix 2

RAs consider the estimate too high with exposure being largely a volatility issue which will be dealt with under the context of contingent capital within the relevant price controls.

- Northern Ireland Gas Product Charges forecast, €5.02m – The UR is actively engaging with NIE PPB on this issue to seek to maximise the economic interests of consumers in the next year. This amount has been removed from the forecast.

- SONI Debt Replacement forecast, €14.5m – The RAs recommend removal of this element. SONI state that they do not have a debt facility in place from 1st October 2017, and argue that this is connected to the SONI Price Control arrangements currently under review by the CMA. This CMA process will not have concluded before 1st October. Such debt facilities have been a matter for respective TSO price controls and therefore the RAs are not minded to include this element as proposed by SONI due to the nature and purpose of the imperfections revenue.

The RAs have recommended for inclusion in the forecast :-

- Long Notice Adjustment Factors forecast, €2.92m – The RAs are currently considering whether the LNAF framework will apply at I-SEM Go-Live. Should a decision be taken not to implement, then the element will be removed from the final tariff calculation.

- Imbalance Price Impact forecast, €16.3m – The RAs reviewed the methodology used by the TSOs and are content that it is the same method as used in previous estimates of uninstructed imbalances and note the task of forecasting the impact is difficult.

The result of the amendments totalling, €30.32m has reduced the Imperfections Revenue Requirement to €183.28m.

Taking into account a K factor adjustment of (€7.34m), this results in a 2017/18 Imperfections Charge of €5.09 per megawatt-hour (MWh), compared with €2.05 per MWh for the 2016/17 tariff year, as shown in Table 1 overleaf.

The RAs are minded to endorse the TSOs' 2017/18 revised Forecast and a K factor adjustment of (€7.34m).

	2017-18	2016-17	Change
Imperfections Allowance (€m)	183.28	146.80	25%
K factor (€m)	(7.34)	(77.56)	
Total Allowance (€m)	175.94	69.24	154%
Forecast Demand (GWh)	34,550	33,700	2.5%
Tariff (€/MWh)	**5.09**	**2.05**	**148.3%**

Table 1: Imperfections Charge 2017/18 versus 2016/17

1.2 2015/16 INCENTIVE OUTTURN

DBC are a significant cost element passed on to the all-island consumer and represent the majority of the Imperfections Charge[3]. In light of the above, the 'Single Electricity Market Incentivisation of All-Island Dispatch Balancing Costs Decision Paper SEM-12-033' (the Decision Paper) introduced an all-island DBC incentive mechanism, with effect from 1 October 2012[4]. The purpose of the incentive mechanism is to give the TSOs a reward for reducing DBC below the forecast, while penalising them for the reverse result; subject to reasonable ex-post model adjustments to the original forecast. Any incentive payment/penalty is split on a 75:25 basis between Ireland's Transmission Use of System (TUoS) and Northern Ireland's System Support Services (SSS) revenues respectively.

The TSOs originally submitted a forecast DBC, for the 2015/16 tariff year of €163.5 million, in May 2015. The PLEXOS element of this forecast stood at €152.4 million, with the supplementary modelling component equalling €11.1 million. The TSOs propose that the PLEXOS component of this forecast is amended, to take account of the following ex-post review factors:

1. Model basecase refinements to include:

    a) "12 months of benefit" principle - allowing the TSOs to gain 12 months of benefit from the Dublin Must Run and South Generation initiatives, introduced in the 2014/15 tariff year. This is achieved by removing the effect of these initiatives from the 2015/16

[3] DBC has accounted for 98-100% of the forecast Imperfections Charge over the last 5 tariff years

[4] SEM-12-033 Incentivisation of All-Island Dispatch Balancing Costs Decision Paper, dated 5 June 2012

forecast, so as to enable the benefit of the initiatives to be realised when comparing the TSOs' outturn performance to the forecast.

b) New Generating Units – Adjustment to account for all Demand Side Units which became operational during the 2015/16 tariff year.
c) North South Net Transfer – Amendment made to adjust the flows that could materialise if a generating unit was to trip in either direction.
d) Generator Technical Offer Data – One unit in Dublin has reduced their minimum load value during 2015/16 and can now provide operating reserve from a lower value helping reduce DBC.
e) Reserve – reserve curves for a number of units were revised to reflect technical issues with these units who were unable to provide reserve times.

2. Combination of actual demand, COD, wind and MIUNs data

In relation to the "12 months of benefit" principle detailed above, the RAs feel that any period of benefit less than 12 months may create a perverse incentive for the TSOs to delay new initiatives until the start of the following tariff year. Furthermore, the RAs feel that a period greater than 12 months may discourage the TSOs from implementing new initiatives as frequently.

The TSOs' 2015/16 Incentive Outturn submission details actual Imperfections Costs of €109.4 million, €10.5 million lower than the ex-post adjusted baseline of €119.9 million[5]. This saving potentially entitles the TSOs to an incentive payment of €0.15 million[6]. This is the third year in which the TSOs have claimed entitlement to an incentive payment, with the TSOs receiving an incentive payment of €0.63m last year, based on the outturn Imperfections Cost for tariff year 2014/15.

The RAs are minded to endorse the payment of this €0.15 million incentive amount to the TSOs, in light of the efficiency gains achieved by the TSOs in reducing outturn Imperfections Costs below the ex-post adjusted baseline.

[5] Calculated as original DBC forecast (163.5m) + model basecase refinements (34.6m) less actual data (81.3m) plus supplementary modeling adjustments (3.03m) = 119.9m

[6] See Appendix 2 – Table 10: Method of calculating the incentive payment with ex-post adjusted baseline

1.3 PROVISION OF COMMENTS

Comments on the 2017/18 Forecast, the 2015/16 Incentive Outturn and the RAs' recommendations in relation to both are invited from industry and the public by 17.00 on Wednesday 2nd August 2017, as detailed in section 11.

Comments on this paper should be forwarded, in electronic form, to Billy Walker at Billy.Walker@uregni.gov.uk.

2 INTRODUCTION

2.1 THE SINGLE ELECTRICITY MARKET

The all-island wholesale electricity market was established as the Single Electricity Market (SEM), in November 2007. 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 dispatches outside 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 Charges, and System Support Charges. The SEM market rules are set out in the Trading and Settlement Code (TSC)[7]. The SEM is governed by the SEM Committee (SEMC) which was set up by the Governments in the Republic of Ireland and Northern Ireland. This Committee has representatives from both RAs, UR in Northern Ireland and CER in the Republic of Ireland, together with an Independent Member. The SEM is operated by the Single Electricity Market Operator (SEMO), which operates as a contractual joint venture between the System Operators EirGrid and SONI.

2.2 OBJECTIVE OF PAPER

The objective of this consultation paper is to solicit comments, from interested parties, on the TSOs' submissions, namely the 2017/18 Forecast and the 2015/16 Incentive Outturn.

2.3 OVERVIEW

[7] http://www.sem-o.com/Search/Pages/SearchResult.aspx?k=trading%20and%20settlement%20code

The Imperfections Charge is levied on suppliers by SEMO. The purpose of the Imperfections Charge is to recover the anticipated DBC (less Other System Charges), Make Whole Payments, any net imbalance between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges over the year, with adjustments for previous years as appropriate. The K factor adjustment mechanism enables any under or over recovery of Imperfections Costs, in the previous year and an estimate for the current year, to be accounted for in the upcoming tariff year. The costs making up the Imperfections Charge are depicted in Figure 1 overleaf and a description of each provided in section 3 below.

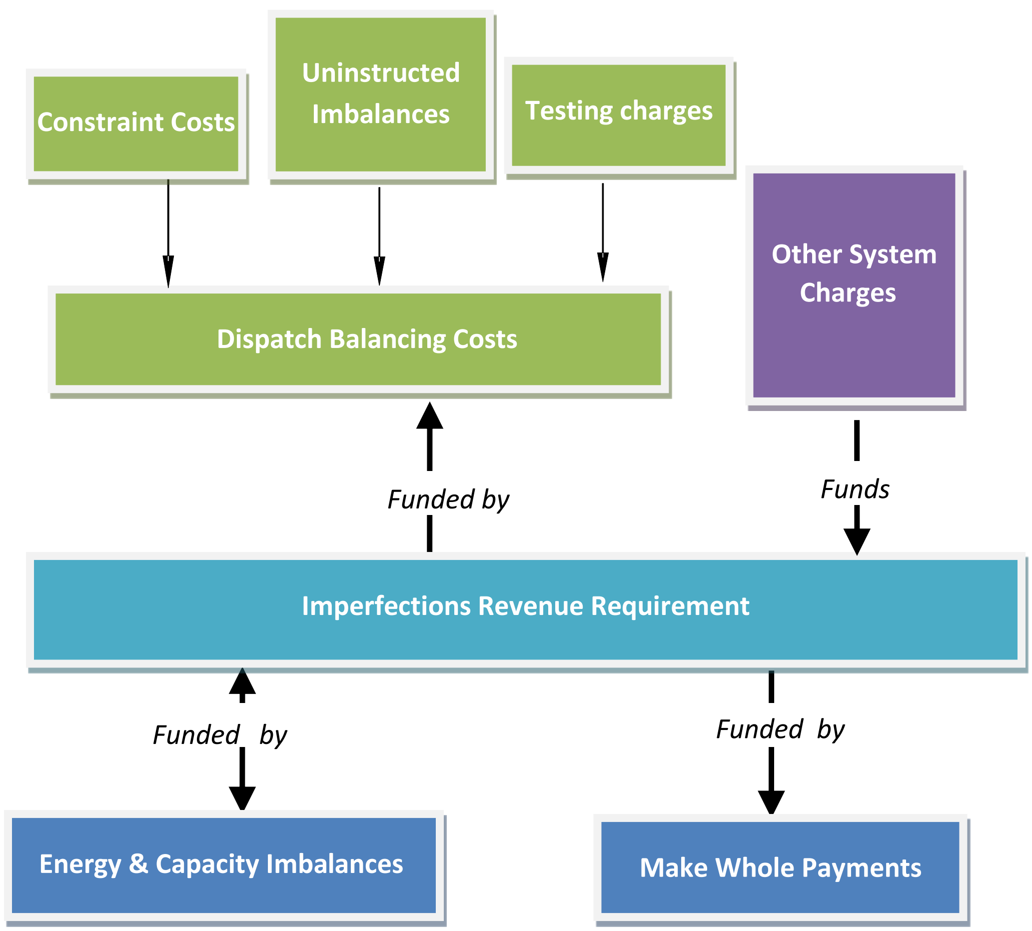

Figure 1: Imperfections Charge Components

3 THE 2017/18 FORECAST

The TSOs' 2017/18 Forecast was prepared jointly by EirGrid and SONI, and captures an all-island estimate of the Imperfections Charge for the 2017/18 tariff year. All costs are estimated ex-ante and recovered from suppliers on a MWh basis, through the Imperfections Charge. The TSOs have forecast an Imperfections revenue requirement of €213.49 million for the 2017/18 tariff year. This forecast has been revised by the RAs to €183.28m.

This represents a 25% increase from the €146.8 million forecast for the 2016/17 tariff year. There are a number of key factors influencing the 2017/18 Forecast, including:

- Over 20% increase in available priority dispatch generation (wind generation in particular) in the unconstrained PLEXOS model which contributes to a lower unconstrained PLEXOS model production cost relative to the constrained PLEXOS model and an increase in forecast constraint costs;

- A 6% reduction in gas prices in the PLEXOS model reduces the production costs in both the unconstrained and constrained PLEXOS models relative to the 2016/17 forecast PLEXOS models; and

- Incorporating the more recent experience of lower levels of forecasted interconnector imports during the day and higher exports during the night contribute to a reduction in forecast constraint costs , as more generating units fall into merit in the unconstrained model , therefore closing the gap between the constrained and unconstrained production costs. However the reduction in Moyle export capacity reduces this impact from 1/11/2017 until the end of the tariff year.

- New Considerations for I-SEM totalling €19.22m which cover I-SEM related uncertainties.

Detail on the forecasts for each of the Imperfections Charge components is provided below and further information regarding the 2017/18 Forecast is provided by the TSOs in Appendix 1.

For the purpose of the 2017/18 Forecast the TSOs had included a cost of €5.02m for Gas Transportation Capacity (GTC) charges. The UR is engaging with Northern Ireland Generators to maximise the economic interests of consumers and therefore has removed this cost from the Imperfections revenue forecast.

3.1 DISPATCH BALANCING COSTS

DBC refers to the sum of Constraint Payments, Uninstructed Imbalance Payments and Generator Testing Charges. DBC makes up 98% of the Imperfections Charge in the 2017/18 Forecast. DBC for the 2017/18 tariff year is forecast as €180.58 million.

3.2 CONSTRAINT PAYMENTS

Constraint Payments make up the entirety of the 2017/18 DBC revised forecast (€180.58m), as Uninstructed Imbalances and Testing Charges are forecast at zero. Constraint Costs arise due to the TSOs having to dispatch some generators differently from the ex-post market unconstrained schedule, in real time, to ensure security of supply on the system. Generators receive Constraint Payments to compensate them for any difference between the market schedule and 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'.

PLEXOS Constraints

The majority of the forecast Constraint Costs are derived using the PLEXOS modelling tool. The RAs have performed validation of the TSOs' PLEXOS model using their in house PLEXOS database. The RAs have sense checked the TSOs' modelling assumptions against an externally validated PLEXOS model produced by the RAs. The RAs have investigated any differences between the models and the TSOs have provided explanations for any divergence from the RAs' validated PLEXOS model. In some cases the TSOs have used actual data rather than the forecast data contained in the RAs' validated PLEXOS model. Additionally, certain parameters were updated to enable a more realistic PLEXOS outcome, based on the TSOs' experience. The PLEXOS element of the TSOs' Constraint Costs forecast is €140.04 million, which has increased significantly from the forecast Constraint Costs of €125.8 million for the PLEXOS component of the 2016/17 tariff year. The reasons for this increase are detailed in the bullet points in section 3 above. The assumptions underlying the TSOs' PLEXOS Constraints are detailed within their submission[8].

[8] Appendix 1 page 14

Supplementary Modelling Constraints

As it is not possible to model all Constraint Cost drivers in PLEXOS, part of the TSOs' Constraint forecast is made up of supplementary modelling results. The supplementary model includes forecasts for the following areas that PLEXOS is unable to effectively model; perfect foresight, specific reserve constraints, specific transmission system constraints, market modelling assumptions, system security constraints and other factors[9]. The 2017/18 forecast for Constraint Costs, derived from supplementary modelling, is €21.3 million. This represents an increase of €2.9 million from the 2016/17 tariff year for standard supplementary modelling and along with €19.22 million for new considerations as described in the executive summary gives an overall cost of €40.52. The largest influencing factor behind this increase is the reduction in the impact of System Operator interconnector countertrading[10].

A provision of €0.63 million for Secondary Fuel start-up tests has been made within the supplementary model. The TSOs have anticipated that the fuel switching arrangements which are currently progressing will come into place in NI in 2017/18. The obligations have been in place in ROI since 2010. The TSOs aim to continue secondary fuel testing during unit start-ups in the 2017/18 tariff period. A provision has been made to constrain on Open Cycle Gas Turbines (OCGTs) and to constrain on the marginal unit during Combined Cycle Gas Turbine (CCGTs) tests for a period of time. A provision has been made for one test for all applicable units during the 2017/18 tariff year. The TSOs have provided a detailed breakdown of how they arrived at the forecast figure for Secondary Fuel start-up testing, at a meeting with the RAs.

Combining both the PLEXOS and supplementary modelling Constraints, a forecast of €180.58 million is included for 2017/18 Constraint Costs, representing an increase of 25% from the 2016/17 forecast of €144.3 million.

3.3 UNINSTRUCTED IMBALANCES

Uninstructed Imbalances occur when there is a difference between a generator unit's dispatch quantity and its actual output. Uninstructed Imbalances and Constraint Costs are related, with Uninstructed Imbalances having a direct effect on Constraints Costs, as TSOs re-dispatch generators to counteract the impact of Uninstructed Imbalances on the system.

[9] See Appendix 1 page 18

[10] See Appendix 1 page 15 for further information on this

A forecast of zero is included for Uninstructed Imbalances as it is assumed that the additional Constraint Costs as a result of Uninstructed Imbalances will, on average, be recovered by the Uninstructed Imbalance payments for the forecast period.

3.4 TESTING CHARGES

The testing of generator units results in additional operating costs to the system, in order to maintain system security. As a testing generator unit typically poses a higher risk of tripping, additional operating reserve will be required to ensure that system security is not compromised, which will give rise to increased Constraint Costs.

A zero forecast has been included for Testing Charges, as it is assumed that any testing generator unit will pay Testing Charges to offset the additional Constraint Costs that will arise from out-of-merit running of other generators on the system as a result of the testing.

3.5 ENERGY IMBALANCES

Energy Imbalances occur in SEM in the event that the sum of Energy Payments to generators does not equal the sum of Energy Charges to suppliers. An Energy Imbalance will generally impact Constraint Costs in the opposite direction, artificially increasing or decreasing the total Constraint Costs. A forecast of zero is included as it is assumed that if Energy Imbalances do occur that they will have an equal and opposite effect on Constraint Costs and will offset any increase or decrease accordingly.

3.6 MAKE WHOLE PAYMENTS

Make Whole Payments account for any difference between the total Energy Payments to a generator and the production cost of that generator on a weekly basis. As such, Make Whole Payments are a feature of the SEM rules and are generally independent of dispatch and DBC. SEMO is responsible for administering all Make Whole Payments and they are funded through the Imperfections Charge. The TSOs have included a forecast of €2.7 million for Make Whole Payments, based on the TSOs' experience of actual outturn, from 1st October 2016 to 31st March 2017, extrapolated out for a 12 month period. Make Whole Payments are not included within the incentive mechanism, as they are viewed as being independent of dispatch and DBC.

3.7 OTHER SYSTEM CHARGES

Other System Charges (OSC) are levied on generators whose failure to provide necessary services to the system lead to higher DBC and Ancillary Service Costs. OSC include charges for generator units which trip or make downward re-declarations of availability at short notice.

In their submission the TSOs assume that generators are compliant with Grid Code and that no charges will be recovered through Other System Charges i.e. a forecast of zero is included for OSC for the 2017/18 tariff year. The TSOs argue that any deviation from this assumption will result in an increase in DBC, and that any monies recovered through Other System Charges will net off the resultant costs to the system in DBC.

3.8 RECOVERY OF IMPERFECTION COSTS

Imperfections Costs are estimated ex-ante and recovered during the following tariff period, through the Imperfections Charge.

Differences between the amount of Imperfections Charges paid out by SEMO to generators and the amounts paid to SEMO by suppliers will lead to instances where SEMO will:

1. Require working capital to fund Imperfections Costs that exceed revenue collected through the Imperfections Charge, or,
2. Have collected revenue through the Imperfections Charge that exceeds the amount being paid out on Imperfections Costs.

To allow for the first scenario, SEMO may require funding from EirGrid Group to cover fluctuations during the tariff period. 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 meet 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 Imperfections Costs (second scenario above), the Imperfections Charge in the following tariff period will be reduced by an appropriate amount to reflect the allowed over-recovery and the associated interest.

The K factor mechanism accounts for any under or over recovery of Imperfections Costs, in previous periods and the current period and adjusts the following period's tariff accordingly. The K factor expected to be applied to the Imperfections Charge for 2017/18 is (€7.34m). This comprises of:

Summary of K factor adjustment

Over-recovery in tariff year 2015/16	(€7.34)
Estimated over-recovery for tariff year 2016/17	(€0m)
Total Imperfections K factor to be applied in 2016/17	(€7.34m)

This €7.34 million over-recovery is netted off the 2017/18 forecast Imperfections Charge leading to a reduction in the Imperfections Charge for the 2017/18 tariff year.

3.9 DEMAND FORECAST

Based on outturn 16/17 demand and 17/18 year to date figures the TSOs have forecast demand for the 2017/18 tariff year at 34,550 GWh, representing a 2.5% increase from the 2016/17 forecast demand of 33,700 GWh.

3.10 IMPERFECTIONS CHARGE

As stated in section 3.2 above, the RAs revised forecast Constraint Costs of €180.58 million are proposed for the 2017/18 tariff year. As the other components of DBC are forecast at zero, this figure also equates to the forecast for DBC. As discussed in section 3.6 above, the TSOs have forecast Make Whole Payments of €2.7 million, based on 2016/17 outturn to date. The remaining elements of the Imperfections Charge are forecast at zero, meaning the forecast Imperfections Charge for 2016/17 stands at €183.28 million. Allowing for the K factor adjustment, provides a total forecast Imperfections Charge of €175.94 million, which when divided by the forecast demand, of 34,550 GWh, equates to an Imperfections Charge of €5.09/MWh for the 2017/18 tariff year.

The comparable figure for the current 2016/17 tariff year stood at €2.05/MWh. Any under or over recovery of Imperfections Costs in the 2017/18 tariff year will feed into the K factor of subsequent tariff years. The trend in the Imperfections Charge is summarised in Table 2 below:

€m	2017-18	2016-17	2015-16	2014-15	2013-14	2012-13
Total Constraints costs	180.58	144.3	163.5	177.6	165.5	142.0
Uninstructed Imbalances	-	-	-	-	-	-
Testing charges	-	-	-	-	-	-
Dispatch Balancing Costs	180.58	144.3	163.5	177.6	165.5	142.0
Energy Imbalance	-	-	-	-		-
Make whole payments	2.7	2.5	7.2	3.6	0.1	0.1
K factor Adjustment	(7.34)	(77.6)	(22.1)	5.2	(18.9)	12.8
Other System Charges	-	-	-	-	-	-
Total Imperfections Charge	**175.94**	**69.2**	**148.6**	**186.4**	**146.7**	**154.9**
Forecast Demand ('000 MWh)	34,550	33,700	33,230	33,320	33,220	32,900
Imperfections Charge/ MWh	**5.09**	**2.05**	**4.47**	**5.60**	**4.42**	**4.71**

Table 2: Imperfections Charge over the years

3.11 RAS PROPOSAL

As stated previously, the RAs have sense checked the assumptions within the TSOs' forecast against the RAs' validated PLEXOS model. The RAs examined any values, in the TSOs' forecast, that differed from those contained in the RAs' validated model and the TSOs provided explanations for the differences.

The RAs reviewed the forecast which included new items for consideration for the 2017/18 tariff year and proposed that the following items, totalling €30.32m are removed.

- Interconnector Ramp Rate Disparity forecast, €10.8m – having liaised with the TSO on the evolving issue of interconnector ramping and the interaction with balancing markets the RAs consider the estimate too high with exposure being largely a volatility issue which will be dealt with under the context of contingent capital within the relevant price controls.

- Northern Ireland Gas Product Charges forecast, €5.02m – The UR is actively engaging with NIE PPB on this issue to seek to maximise the economic interests of consumers in the next year. This amount has been removed from the forecast.

- SONI Debt Replacement forecast, €14.5m – The RAs recommend removal of this element. SONI state that they do not have a debt facility in place from 1st October 2017, and argue that this is connected to the SONI Price Control arrangements currently under review by the CMA. This CMA process will not have concluded before 1st October. Such debt facilities have been a matter for respective TSO price controls and therefore the RAs are not minded to include this element as proposed by SONI due to the nature and purpose of the imperfections revenue.

The RAs have proposed that the following items totalling €19.22m are included within the forecast.

- Long Notice Adjustment Factors forecast, €2.92m – The RAs are currently considering whether the LNAF framework will apply at I-SEM Go-Live. Should a decision be taken not to implement, then the element will be removed from the final tariff calculation.

- Imbalance Price Impact forecast, €16.3m – The RAs reviewed the methodology used by the TSOs and are content that it is the same method as used in previous estimates of uninstructed imbalances and note the task of forecasting the impact is difficult.

The RAs are minded to endorse the revised 2017/18 Forecast and a K factor adjustment of (€7.34m). The RAs welcome any comments on this proposal and the TSOs' submission.

4 INCENTIVE OUTTURN SUMMARY 2015/16

The TSOs are responsible for managing DBC through efficient dispatch of generation, while still maintaining a secure electricity system. In light of this, a process to incentivise the TSOs to reduce DBC was introduced by the SEMC, with effect from 1 October 2012. The current parameters, as detailed in the Decision Paper[11], are presented in Table 3 below. Any payments or penalties associated with the incentivisation of DBC are administered across both TSOs on a 75:25 split basis.

[11] SEM-12-033 Incentivisation of All-Island Dispatch Balancing Costs Decision Paper, dated 5 June 2012

	Lower Bound	Dead Band	Upper Bound	Below Target	Above Target
Dispatch Balancing Costs	7.5% - 20% below baseline	7.5% below and above the baseline	7.5% - 20% above baseline	TSOs retain 10% of every 2.5% below	TSOs penalised 5% of every 2.5% above

Table 3: DBC incentive parameters

The cost categories included in the incentive baseline are detailed in the Decision Paper and listed in Table 4 below:

INCLUDED	NOT INCLUDED
Constraint Costs	Make Whole Payments
Uninstructed Imbalances	Capacity Imbalances
Testing charges	Other Imperfection Charge Components
Energy Imbalances	
Other System Charges	
SO-SO Trades	

Table 4: Cost categories included in the DBC incentivisation mechanism

The 2015/16 tariff year is the fourth year to fall within the incentive mechanism and the third year where an incentive payment is potentially due. EirGrid and SONI's assessment of the incentive outcome for the 2015/16 tariff year is attached as Appendix 2 to this paper[12]. The TSOs' assessment provides for outturn Imperfections Costs of €109.4 million; €10.5 million lower than the ex-post adjusted baseline. Based on this, the TSOs are potentially entitled to an incentive payment of €0.15 million. The resultant incentive payment would be applied on a 75:25 split between Ireland's Transmission Use of System (TUoS) and Northern Ireland's System Support Services (SSS) revenues respectively.

5 EX-POST REVIEW FACTORS

The ex-post review is designed to take into account any external factors which heavily influenced DBC during the tariff period, e.g. unforeseen long-term outage of plant and other High Impact Low Probability events (HILPs). An effective ex-post adjustment mechanism should ensure the

[12] Appendix 2 - Imperfections Costs Incentive for Tariff Year 1st October 2015 – 30 September 2016, submitted by the TSOs on 31 March 2017

protection of both the TSOs and the all-island consumer from potential windfall gains or losses, as it removes some of the risk for events outside of the TSOs' influence.

Table 6 of the Decision Paper details the allowable ex-post review factors as follows:

- Change in SEM market rules or any RA decision affecting DBC
- Changes in demand forecast/exchange rates/fuel prices (inc. bids)/wind generation
- High Impact Low Probability (HILP) events: long-term unforeseen outage of generators, key reserve provider or transmission plants.

In addition to the above, the Decision Paper states that the RAs will, as part of the ex-post review, examine any significant factors not identified above which affected DBC outturn. Combinations of the above factors which lead to DBC outturn being 10% either side of the ex-ante baseline will also be reviewed in detail by the RAs. The SEMC consider the ex-post review process enables a more accurate and effective incentive mechanism.

The TSOs submitted the 'Forecast Imperfections Revenue Requirement for Tariff Year 1st October 2015 to 30th September 2016' (ex-ante DBC forecast) in May 2015. This submission forecast DBC for the 2015/16 tariff year at €163.5 million. The 2015/16 Incentive Outturn paper contains the TSOs' ex-post adjustments to this €163.5 million baseline, to form an ex-post adjusted baseline of €119.9 million. Details of the adjustments made to the ex-ante DBC forecast are discussed in the proceeding paragraphs. The TSOs's submission contains information on the key assumptions within the ex-ante and ex-post PLEXOS modelling process[13].

5.1 PLEXOS MODEL BASECASE REFINEMENTS

In their 2015/16 Incentive Outturn submission the TSOs assert that the combined effect of the PLEXOS model basecase refinements, detailed below, is to increase the originally submitted (ex-ante) PLEXOS model from €152.4 million to €187 million.

[13] Appendix 2

Initiatives introduced in 2014/15

The TSOs introduced a number of operational initiatives at various points in the 2014/15 tariff year. The TSOs have adjusted the 2015/16 ex-ante DBC forecast to allow for 12 months of benefit from each initiative. These initiatives are outlined below:

a. Dublin Must Run Generation - The Dublin load based operational constraint for one unit increased from 4400 MW to 4600 MW in February 2015. The model was amended so that the value was 4400 MW until February 2016 and 4600 MW thereafter.

b. South Generation – In July 2015 a new south load based transmission Constraint Group (TCG) was added to replace the southwest generation constraint. The model was amended so that the old rule of two units by day/three by night was used until July 2016 and the new load based rules were used thereafter.

RAs Proposal

The RAs are minded to endorse the '12 months of benefit' principle and to allow for the above amendments, to the ex-ante DBC baseline. The RAs are cognisant of the fact that not allowing 12 months of benefit, for each new TSO initiative, may provide the TSOs with a perverse incentive to delay new initiatives, until the beginning of the next tariff period. Furthermore, the RAs feel that any period longer than 12 months may disincentivise the TSOs from introducing new initiatives on as frequent a basis. This "12 months of benefit" principle may be applied to any outperformance of System Non-Synchronous Penetration (SNSP) targets, achieved by the TSOs, as part of the DS3 programme. The RAs welcome any comments on this proposal.

New Generating Units

The TSOs made the following adjustments to the ex-ante DBC baseline to account for these new generating units:

a. Demand Side Units (DSUs) - DSUs can become commercially operational significantly quicker than conventional generating units and windfarms. The ex-ante DBC model was therefore updated to include all DSUs which became operational during the 2015/16 tariff year.

North South Net Transfer Capacity

The Operational Constraints outlines how the Total Transfer Capacity from North to South cannot exceed 450 MW while the South to North value cannot exceed 400 MW. Plexos requires a static value called Net Transfer Capacity to be inputted for the model to solve. This valus should account for any rescue flows that could materialise if a generating unit was to trip in either jurisdiction. In the original plexos model a static NTC of 300 MW was applied for flows in both directions. When optimising the dispatch schedule, the TSO scheduling tool optimises the 275kV tie-line flow such that the Total Transfer Capacity including rescue flows is not breached. This is influenced by transmission outages, the level of wind generation in either jurisdiction , regional location of wind and where other generation is being sourced.
The TSOs carried out desktop analysis and found that the actual NTC value was lower than the 300 MW included in the original model. The TSOs included revised hourly NTC values into the constrained Plexos model for flows in the direction of South to North. This revised NTC was based on the actual TTC value that was used in real time based on transmission outages. The average South – North value was 156 MW, while at times this could be up to 311 MW.

Generator Technical Offer data

One unit in Dublin reduced their minimum load value during 2015/16 and can now provide operating reserve from a lower value. This helped reduce DBC as the unit had been constrained on and the reduction in minimum load helped bring it into merit in the SEM

Reserve

Reserve curves for a number of units were revised to reflect technical issues with these units who were unable to provide reserve at times.

RAs Proposal

As stated above, the SEMC Decision Paper on DBC Incentivisation states that the RAs will, as part of the ex-post review, examine any significant factors not identified which affected DBC outturn. Although the above factors are not specifically referred to as allowable ex-post review adjustments, in the Decision Paper, the RAs are minded to allow for their inclusion. Allowing for these amendments provides a more accurate ex-post DBC baseline by which to assess the TSOs' performance. The TSOs' have advised that if the refinements for new generating units and interconnector adjustments were not made that the ex-post adjusted baseline would be higher and the TSOs outturn performance appear better as a result. The RAs are keen to ensure as transparent an ex-post review process as possible.

The RAs welcome any comments on this proposal.

5.2 SEM RULES OR ANY RA DECISION

The TSOs reviewed any changes to SEM market rules and any RA decision that became effective between the data freeze date of 30/04/2015 and the end of the 2014/15 tariff year. The TSOs identified that there were no changes to the SEM rules or RA rule changes which impacted on the 2015/16 ex-post review process.

5.3 DEMAND

The actual average monthly demand for Ireland was 3% lower than forecast, while the actual demand for Northern Ireland was in line with forecast. When actual demand figures were rerun in PLEXOS, DBC decreased by 6.5%, therefore meeting the criteria for inclusion in the ex-post adjustment process[14].

5.4 WIND

Actual all-island wind availability was in line with the assumed wind availability in the submitted ex-ante DBC forecast. The PLEXOS check of actual wind indicated that it did not have a material impact on DBC for tariff year 2015/16. This model rerun showed a decrease in DBC of less than 2% when compared with the submitted ex-ante DBC forecast. This change to DBC did not meet the criteria for inclusion in the ex-post adjusted model, when considered in isolation.

5.5 COMMERCIAL OFFER DATA & MIUNS

Actual Commercial Offer Data (COD) was compared to the submitted ex-ante forecast COD and these differed significantly. The main reason for this was a significant reduction in wholesale fuel prices across the island. The impact of the generator COD was assessed in PLEXOS and this resulted in a reduction to the DBC ex-ante baseline of 34%.

[14] Per SEM-12-033 Incentivisation of All-Island Dispatch Balancing Costs, Table 6

When the original 2015/16 forecast was submitted flows on both interconnectors were predominatly imports to SEM prior to the data freeze. From 1/04/2015 flows changed significantly due to the increase of the Carbon Price Floor in Great Britain. As a result the level of imports into SEM reduced during the day and the levels of exports into GB increased during the night from this date. Actual Interconnector flows for 15/16 were updated as these differed significantly from forecasted flows. The impact of the actual MIUNs on DBC was assessed in PLEXOS and resulted in a reduction to DBC of 4%.

The actual COD (including actual MIUNs) was considered material and a rerun of the PLEXOS model was carried out. This resulted in a €71 million decrease to DBC, which equates to a 38% reduction, to the ex-ante DBC baseline. As this exceeds the threshold of 3% of the baseline, this warrants inclusion in the ex-post adjusted model.

5.6 COMBINATION OF DEMAND, WIND AND COD & MIUNS

When rerun in PLEXOS the combination of actual demand, actual wind availability and actual COD (including MIUNs) caused a €81.3 million (€187 million - €105.7 million) decrease to the ex-ante DBC baseline (including model refinements discussed above). This equates to a 43% decrease in DBC and meets the 8% threshold for inclusion in the ex-post adjusted model.

5.7 HILP EVENTS

Transmission outages, both forced outages and scheduled outage overruns, were assessed by the TSO for the 2015/16 tariff year. Generator forced outages, scheduled outage overruns and generator issues were also examined. The combination of the generation and transmission outages did not met the HILP criteria as they resulted in a change in DBC of less than 1%. This was therefore not considered material and was not included in the ex-post adjustment process.

5.8 CONCLUSION ON EX-POST PLEXOS ADJUSTMENTS

PLEXOS Results

The above amendments relate to the PLEXOS modelled component of the DBC forecast and result in an ex-post PLEXOS component value of €105.7 million. The PLEXOS portion of the DBC forecast has decreased, relative to the ex-ante forecast of €152.4 million, largely due to actual COD & MIUN levels differing from forecasts.

	€m
Ex-ante DBC PLEXOS forecast	152.4
PLEXOS Model basecase refinements	34.6
Adjustments for actual demand, exchange rates, wind, COD & MIUNs	(81.3)
Ex-post DBC PLEXOS value	105.7

Table 5: PLEXOS amendments in the Ex-post review process

RAs Proposal

As with the TSOs' 2017/18 Forecast, the RAs have sense checked the reasonableness of the TSOs' PLEXOS models against the RAs' validated PLEXOS model. The RAs investigated any reasons for differences between the models and the TSOs provided justification and evidence to explain any divergences.

The €81.3m of adjustments, for actual data, shown in table 5 above are clearly defined as allowable ex-post adjustment factors within the Decision Paper. Furthermore the Decision Paper states that the RAs will, as part of the ex-post review, examine any significant factors not identified in table 6 of the Decision Paper. The RAs feel the PLEXOS model basecase refinements should be included in order to ensure the TSO's performance is gauged against as accurate an ex-post DBC forecast as possible. The RAs are minded to endorse the above amendments to the ex-ante DBC PLEXOS forecast.

The RAs welcome any comments on this proposal.

6 SUPPLEMENTARY MODELLING RESULTS

The supplementary modelling is designed to take account of the specific external factors that cannot be captured by the PLEXOS model. The TSOs have calculated an ex-post supplementary model DBC value of €14.13 million. This represents an increase of €3.03 million from the submitted ex-ante forecast. System Operator Interconnector Trades for countertrading account for the majority of this €3.03 million movement from the ex-ante forecast. The results of the supplementary modelling process are summarised in Table 8 of the TSOs submission[15].

The table below shows the effect of both the PLEXOS and supplementary modelling ex-post amendments on the Constraint Costs forecast.

€m	Ex-ante DBC baseline	Ex-post adjusted DBC baseline
PLEXOS	152.4	105.73
Supplementary model	11.1	14.13
Total constraints	163.5	119.86

Table 6: Total constraints

RAs Proposal

As stated previously, the supplementary modelling takes account of the specific external factors that cannot be captured by the PLEXOS model. The RAs have checked the TSOs' supplementary model for accuracy and reasonableness of assumptions and are minded to endorse the above amendments.

The RAs welcome any comments on this proposal.

7 OUTTURN DBC

RAs Proposal

The table below shows the total Imperfections Costs, allowing for each of the RAs above proposals:

[15] Appendix 2

	Actual Outturn €m
Dispatch Balancing Costs	121.2
Energy Imbalance	(4.3)
Other System Charges	(7.5)
Total Imperfections Costs	**109.4**

Table 7: Actual Outturn Imperfections Costs

8 IMPERFECTIONS OUTTURN AND INCENTIVE CONCLUSIONS

As shown in table 7 above, actual Imperfections Costs for the tariff year 2015/16 are €109.4million. This is €10.5 million lower than the ex-post adjusted baseline of €119.9 million, shown in table 6 above. The table below summarises the 2015/16 Incentive Outturn.

€m	**2015/16**		
	Actual	**Ex-post baseline**	**Ex-ante forecast**
Total constraints	125.33	119.90	163.50
Uninstructed Imbalances	(2.94)	-	-
Testing charges	(1.19)	-	-
Total DBC	**121.2**	**119.90**	**163.50**
Energy Imbalance	(4.30)	-	-
		-	-
		-	-
Other System Charges	(7.50)	-	-
Total Imperfections Charge	**109.40**	**119.90**	**163.50**

Table 8: Actual v Forecast Imperfections Costs

Based on this the TSOs are entitled to an incentive payment of €0.15 million. The €0.15 million is calculated in accordance with table 3, 'DBC Incentive Parameters' above. The €10.5 million saving equates to an 8.75% reduction to the ex-post adjusted Imperfections Cost, and the TSOs have calculated the €0.15 million by extrapolating between 7.5% and 10.0% under budget.

RAs Proposal

The TSOs calculation is in accordance with the Decision Paper on DBC incentivisation and the TSOs have provided further breakdown of their calculation within table 10 of their submission[16]. The RAs are minded to endorse the payment of €0.15 million to the TSOs, in line with the specified proportions.

8.1 TSO EFFICIENCY GAINS

The TSOs have continued to introduce a significant number of operational initiatives to help reduce DBC. The TSOs assert that the €10.5 million saving was achieved largely through the following:

1. Dublin Must Run – the TSOs changed the operational constraint of requiring 3 units by night/2 units by day in Dublin. The TSOs needed to account for the full 12 months of benefit of this initiative, introduced in the 2013/14 tariff year. The model applies only to the new operational constraint rules from 25/10/2014 to 25/10/2015
2. North – South Total Transfer Capacity – A change made on scheduling software used by the TSOs on 15/11/2014 refined the modelling of North – South reserve flows. The scheduling tool had considered that all reserve held in Ireland would flow South to North in the event of a generator trip in Northern Ireland. In reality this would not be the case as the reserve flow would be limited by the size of the generator to trip coupled with the fact that there would also be utilisation of the reserve held in Northern Ireland. This software was further refined in June 2016to increase the amount of reserve that was available in Northern Ireland if a generator tripped in this jurisdiction. This helped increase the flows at times from South to North.
3. SNSP- Following a successful trial from October 2015 the non-synchronous generation limit permanently changed from 50% to 55%. This increased limit came into effect on 01/03/2016.
4. Dublin Generation Rules- From 24/05/2016 the requirement for generation in North and South Dublin was changed to reflect changing generator characteristics along with system stability requirements.

[16] See Appendix 2 page 18

9 DBC FORECAST & INCENTIVISATION IN THE I-SEM

The 2017/18 Forecast covers the period to the end of the SEM and also four months of the I-SEM. The forecast for the 2018/19 tariff year will be based on different parameters, under the new European Integrated model. As the Integrated Single Electricity Market (I-SEM) design is likely to differ from the current SEM design any incentivisation mechanism, around DBC in the I-SEM, will have to reflect these market differences. Given time constraints, there may not be an incentive mechanism in place for the first year of the I-SEM, however it is important that an accurate DBC forecast is in place for tariff setting purposes.

10 TSOS REPORTING AND TRANSPARENCY MEASURES

In order to increase transparency around DBC, the SEMC has introduced reporting requirements on the TSOs. The TSOs provide quarterly updates on the levels of Constraint Costs, drivers behind Constraint Costs, mitigating measures being taken and other information or commentary that the TSOs believe will aid transparency in this area.

These Quarterly Imperfections Costs Reports are available on EirGrid's and SONI's websites. The most recent report relates to the period January to March 2017[17] and includes a Year-to-Date section.

11 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@uregni.gov.uk by 17:00 on Wednesday 2nd August 2017.

[17] SONI Ltd - Publications