Imperfections Cost Incentive

For Tariff Year 2014/15

24/03/2016

EIRGRID SONI

Executive Summary

Dispatch Balancing Costs (DBC) are an inherent feature of the SEM design and arise due to the difference between the ex-post market schedule and the real-time dispatch. These costs are levied on Suppliers through the Imperfections Charge. EirGrid and SONI, as Transmission System Operators (TSOs), are responsible for managing DBC through efficient dispatch of generation, while still maintaining a secure electricity system.

A process to incentivise the TSOs to reduce DBC was announced by the Regulatory Authorities (RAs) in June 2012. A set of targets, dead-bands, payments and penalties were established to provide benefits to the all-island customer through the reduction of Imperfections Costs. Since the establishment of the incentive process the TSOs, through the introduction of operational initiatives, have reduced Imperfection Costs (excluding Make Whole Payments) by €73 million as follows:

- 2012/13 €3 million
- 2013/14 €52.4 million
- 2014/15 €17.2 million

These savings are not only realised in the year in question but also create savings in the following years as they become normal operational standards. This submission by the TSOs sets out the actual outturn and compares this with an ex-post adjusted Imperfections revenue requirement for the 2014/15 tariff year. This forms the basis of the calculation of an incentive payment.

The components of the outturn Imperfections Costs that are subject to the incentive mechanism are: Dispatch Balancing Costs (DBC), System Operator (SO) Trades, Energy Imbalances, and Other System Charges with the primary component being DBC. In the ex-post review process, material factors that are outside the control of the TSO, and fulfil a set of predefined criteria, are subject to an ex-post adjustment mechanism. This involves an update to the models and calculations carried out for the original Imperfections revenue requirement with actual data. There were two categories which were considered material, and included in the ex-post adjustment process:

1. Model basecase refinements; and
2. Actual demand, actual exchange rates, actual Commercial Offer Data (COD) including Modified Interconnector Unit Nominations (MIUNs) and actual wind.

The outturn Imperfections Costs incurred over the Tariff Year 2014/15 were €128.7 million; €17.2 million lower than the ex-post adjusted Imperfections revenue requirement. This saving is consistent with the initiatives and focus applied during the year by the TSOs, in particular (but without limitation to) countertrading for reserve co-optimisation and further focus on must-run generation constraints in Dublin.

The savings made by the TSOs during Tariff Year 2014/15 meet the requirements for receiving an incentive payment of €0.63m.

1. Introduction

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

The submission is for the period from 01/10/2014 to 30/09/2015 inclusive, referred to as the Tariff Year 2014/15. Actual outturn was measured against an ex-post adjusted Imperfections revenue requirement referred to as the ex-post adjusted baseline. The original Imperfections revenue requirement is referred to as the submitted forecast. The components of the outturn Imperfections Costs that are subject to the incentive mechanism are: Dispatch Balancing Costs (DBC), System Operator (SO) Trades, Energy Imbalances and Other System Charges, with the primary component being DBC.

The Single Electricity Market Committee (SEMC) introduced an incentive mechanism on the TSOs to reduce all-island Imperfections Costs from the period 1 October 2012 onwards. The incentive mechanism takes account the current industry structure and the degree of control which the TSOs have on the cost drivers. The incentive mechanism includes an ex-post adjustment mechanism to ensure the protection of both the TSOs and all-island customers from potential windfall gains or losses, by removing some of the risk for events outside of the TSOs' control. Since the introduction of the incentive process the TSOs, through the introduction of operational initiatives have reduced Imperfection Costs (excluding Make Whole Payments) by €73 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m). These savings are not only realised in the year in question but also create savings in the following years as they become normal operational standards.

Data checks of actual data compared with submitted forecast data were carried out to identify which cost drivers were eligible for the ex-post adjustment mechanism as per the incentive criteria. The submitted forecast was €177.6 million. This was updated with actual data that met the criteria for inclusion, to form the ex-post adjusted baseline of €145.9 million. This was compared with the outturn Imperfections Costs for Tariff Year 2014/15 to ascertain whether an incentive or penalty payment was due.

The outturn Imperfections Costs[1] were €128.7 million, €17.2 million lower than the ex-post adjusted baseline. These savings are a result of the measures implemented by the TSOs during the Tariff Years 2013/14 and 2014/15. The results of the incentive process are set out in Figure 1.

[1] Imperfection Costs comprise of initial settlement data and includes the resettlement data from two SEM Settlement disputes raised by the TSOs

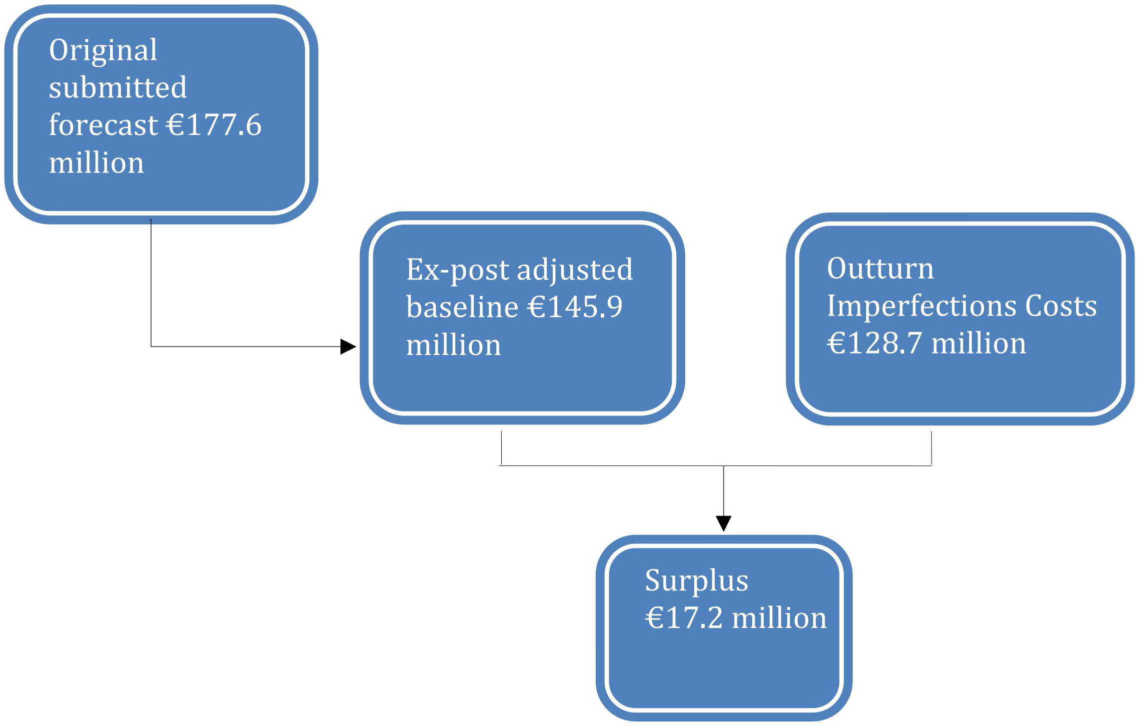

Figure 1: Flowchart of the results of the incentive process.

2. Overview of the Incentive Mechanism

To promote the effective management and reduction of outturn Imperfections Costs by the TSOs, the SEMC introduced the incentive mechanism in the 2012 decision paper SEM-12-033[2]. It outlines the agreed incentive mechanism which requires the TSOs to ex-post adjust the submitted forecast for material items that are outside of the TSOs' control. The original Imperfections revenue requirement for Tariff Year 2014/15 was €177.6 million.

To allow participants to understand the material cost drivers and the impact Imperfections Costs has on the all-island customers, the TSOs publish a Quarterly Imperfections Costs Report on their website[3].

2.1. Cost categories included in the incentive mechanism

The cost categories for the incentive mechanism are set out in SEM-12-033 and are repeated below in Table 1.

Category	Included	Reason
Constraint Costs	Yes	Constraints costs are forecast by the TSOs. The constraints costs depend on a range of factors.
Uninstructed Imbalances	Yes	TSOs' influence is solely on the design of Uninstructed Imbalance (UI) tolerance parameters, such as Tolerances for Over and Under Generation, which are proposed by the TSOs.
Testing Charges	Yes	Testing charges are proposed by the TSOs and approved by the SEMC. The testing charge received into the Imperfections pot is dependent on the number of units under test and length of time a generating unit is under test.
Energy Imbalances	Yes	Link between Energy Imbalances (EI) and Constraint Costs as EI increase or decrease total Constraint Costs.
Other System Charges	Yes	Short Notice Declarations (SNDs), Trip Charges and Generator Performance Incentives (GPIs) are proposed by the TSOs. The amount of Other System Charges (OSC) received into Imperfections pot is dependent on level of non-compliances of generating units and is related to the additional costs as a result of the associated performance of generator units.
SO Trades	Yes	For system security and priority dispatch, the TSOs can

[2] Decision Paper on Incentivisation SEM-12-033
[3] Quarterly Imperfections Costs Reports

		countertrade utilising the Residual Capacity Unit.
Make Whole Payments	No	Independent of dispatch and DBC.
Capacity Imbalances	No	Outside control of TSOs.
Other Imperfection Charge components[4]	No	Outside control of TSOs.

Table 1: The cost categories considered for the incentive mechanism.

2.2. Components of the submitted forecast for the incentive

The following sets out the manner in which the components of Imperfections Costs, subject to the incentivisation process, are accounted for in the submitted forecast.

2.2.1. Dispatch Balancing Costs (DBC)

In the submitted forecast, DBC, the sum of Constraint Costs, Uninstructed Imbalances and Testing Tariffs, are derived from a PLEXOS model and supplementary modelling.

2.2.2. Energy Imbalance (EI)

In the submitted forecast, it is assumed that no Energy Imbalance will arise. If imbalances occur, they are assumed to have an equal and opposite effect on constraints and will offset any increase or decrease accordingly.

2.2.3. Other System Charges (OSC)

OSC are levied on generators whose failure to provide necessary services to the system lead to higher DBC and Ancillary Services Costs. OSC are netted off Imperfections Costs. A zero estimate was made in the submitted forecast which assumed the generators are compliant with Grid Code and no charges are recovered through OSC. Any deviations from Grid Code compliance would result in an increase in DBC. Deviations from Grid Code non-compliance, recovered through OSC, would result in reducing the resultant costs to the system in DBC.

2.3. Ex-post review factors

The ex-post adjustment mechanism considers any factors which materially influence outturn Imperfections Costs e.g. unforeseen long-term outage of plant and other High-Impact Low-Probability (HILP) events. The factors for consideration in the ex-post review are set out in Table 2.

[4] Market Interest and Foreign Exchange elements as set out in the Trading and Settlement Code.

Factor	Level of effect on DBC	Ex-ante Baseline Adjustment
Change in SEM market rules or any RA decision affecting DBC	Automatic shift of any percentage.	SEM market rules can change during a tariff period after the ex-ante allowance has been made. These changes may have an effect on DBC outturn. If the impact of a market rule change results in any change on DBC outturn the baseline will be adjusted[5].
Changes in Demand Forecast/Exchange rates/Fuel prices (inc. bids)/Wind generation	3%+ either side of DBC baseline. Or Total 8%+ either side of DBC baseline.	Forecasts for each of these categories are included in the PLEXOS modelling of constraint costs by the TSOs. In the case of Wind forecasting a specific provision is made for the tariff period. • If the impact of the difference between forecast and actual for each category on DBC outturn is 3%+ of the baseline (in either direction), it will be adjusted[6]. • If the impact of the difference between forecast and actual of all four categories in combination on DBC outturn is 8%+ of the baseline (in either direction), it will be adjusted[7].
High Impact Low Probability (HILP) events: long-term unforeseen outage of Generators, key reserve provider or transmission plants.	5%+ of DBC baseline or €5M per event	HILPs events are rare transmission, generation or interconnector outages that lead to significant increases in constraint costs. PLEXOS does not model major HILP events. • If a Generator, key reserve provider or transmission plant going on unforeseen long-term outage (including single and multiple HILP events) results in DBC outturn increasing by 5%+ from the ex-ante baseline, it will be adjusted[8].

Table 2: The factors for consideration in the ex-post review.

[5] For example, the ex-ante baseline for Tariff Year X is €100 million. The measured impact of a market rule change is €2 million (i.e. 2% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €2 million, either to €98 million or €102 million.

[6] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of the difference between forecast and actual fuel cost prices solely is €5 million (i.e. 5% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €5 million, either to €95 million or €105 million. If the impact of the difference had been €2 million (i.e. 2% of the baseline), the baseline would not have been adjusted.

[7] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of the difference between forecast and actual of all four categories in combination is €12 million (i.e. 12% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €12 million, either to €88 million or €112 million. If the impact had been €6 million (i.e. 6% of the baseline), the baseline would not have been adjusted.

[8] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of three Generation plants going on unforeseen long-term outage is €10 million (i.e. 10% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €10 million, either to €90 million or €110 million. If the impact of the difference had been €4 million (i.e. 4% of the baseline), the baseline would not have been adjusted.

As part of the ex-post review, if there are additional significant factors to those outlined in Table 2, the combination of which leading to DBC outturn being 10% either side of the ex-ante baseline, these will be examined by the TSOs and may by be deemed eligible for an ex-post adjustment.

2.4. Asymmetric targets and dead-band

SEMC set out targets, payments and penalties for the Tariff Year 2014/15. These payments and penalties associated with the incentivisation of DBC are administered across both TSOs on a 75:25 split basis, upon ex-post review. The asymmetric targets and dead-band parameters are set out in Table 3.

€m's	Lower Bound	Dead Band	Upper Bound	Below Target	Above target
Dispatch Balancing Costs	7.5%-20% below baseline.	7.5% either side of the baseline.	7.5%-20% above baseline.	TSOs retain 10% of every 2.5% below.	TSO penalised 5% of every 2.5% above.

Table 3: The asymmetric targets and dead-band parameters.

3. Data Comparison Checks

Data checks comparing actual and forecast values were carried out to identify significant differences between the submitted forecast and reality. Data checks comprise a desktop comparison and, where required, a rerun of the DBC model in PLEXOS. When there was a material change, the submitted forecast was updated with this information.

3.1. PLEXOS model basecase refinements

During the ex-post review process three refinements were required to the original 2014/15 forecast PLEXOS model to ensure a more accurate and robust basecase on which to measure the qualifying criteria. The refinements are as follows:

3.1.1. Initiatives introduced in 2013/14

The TSOs introduced a number of operational initiatives at various points in the 2013/14 tariff year and these helped to reduce DBC by €52.4 million during that year. The TSOs needed to amend the resubmitted PLEXOS model to allow the TSOs to gain a minimum of twelve month benefit[9] of the initiatives outlined as follows:

1. **Dublin Must Run Generation**
   The number of units in the Dublin operational constraint for voltage support was reduced from three by night/two by day to two (plus EWIC) at all times, following a period of successful testing on 25/10/2013. The original 2014/15 forecast submitted to the RAs included the new operational constraint rules for the entire tariff year, therefore this needed to be readjusted so that the old operation rule of three by night/two by day was effective from 01/10/2014 to 25/10/2014 and the new rule of two (plus EWIC) at all times was made effective after this date.
2. **Reserve Co-Optimisation**
   Countertrading for reserve co-optimisation was introduced by the TSOs on 03/03/2014 following consultation with the RAs. The principle behind this initiative was that the TSOs would countertrade with Great Britain (GB) to export across EWIC in order to prevent it from becoming the Largest Single Infeed (LSI). By doing this it meant that EWIC could still hold reserve and the amount of reserve required on the island was minimised. The original 2014/15 forecast submitted to the RAs included an estimate of both the production cost saving and revenue from the trades as part of the supplementary modelling for the entire tariff year. This therefore needed to be readjusted as only approximately six months (03/03/2014 to 30/09/2014) of this benefit were realised by the TSOs in the 2013/14 tariff year, therefore this was applied from 01/10/2014 to 03/03/2015. In order to assess this benefit the PLEXOs model needed to be amended to allow it to countertrade for reserve co-optimisation from 03/03/2015. Furthermore this change required the reserve calculation in the resubmitted model to be changed as the reserve calculation in the original submission was simplified due to the fixed interconnector flows.

[9] The TSOs have applied this on the basis that they are entitled to a minimum of twelve months benefit for any initiative introduced. Indeed it may be necessary to apply an initiative for a full tariff year following the tariff year in which it was introduced in order to gain the full benefit of this and for the incentive to be effective.

3.1.2. New Generating Units

When the original 2014/15 forecast was submitted in April 2014 the TSOs needed to make a number of assumptions around the connection dates of new generation capacity. Furthermore as these units had not yet undergone testing the technical and commercial parameters of these units could only be estimated. The following changes were made:

1. **Great Island**
   The new Great Island Combined Cycle Gas Turbine (CCGT) went into commercial operation on 16/04/2015. The original 2014/15 forecast assumed a commercial operational date of the start of the tariff year i.e. 01/10/2014. The technical and commercial parameters, determined by the owner, also changed considerably than those originally used. These parameters needed to be updated in the basecase model.
2. **Demand Side Units (DSUs)**
   DSUs can become commercially operational significantly quicker than conventional generating units and windfarms. The basecase model was therefore updated to include all DSUs which became operational during the 2014/15 tariff year.

3.1.3. Interconnector Adjustments

When the original 2014/15 forecast was submitted fixed flows were utilised on both interconnectors as this was the trend at the time of submission. During the year the flows on both interconnectors changed significantly, predominately due to the increase of the Carbon Price Floor in Great Britain on 01/04/2015. In the original submission the import and export limits on both interconnectors were not binding due to the fixed flow profiles utilised, however due to the change in actual flows these needed to be changed as follows:

- Moyle: Export limit from SEM to GB increased from 80 MW to 250 MW as measured in Northern Ireland;
- EWIC: Export limit from SEM to GB increased from 400 MW to 526 MW as measured in Ireland; and
- EWIC: import limit from GB to SEM increased from 500 MW to 504 MW.

Furthermore refinements were made to how the Moyle interconnector was modelled to align this with that used for EWIC. This was due to the actual flows which occurred during the 2014/15 tariff year.

These basecase refinements changed the original PLEXOS model from €181.5 million to €185 million.

3.2. 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 27/03/2014 and the end of the period in question. There were no changes to the SEM rules or RA rule changes which impacted on the 2014/15 process.

3.3. Demand

The actual average monthly demand for Ireland was found to be 1% lower than forecast while that of Northern Ireland was 5% lower than forecast. The PLEXOS check of actual demand alone indicated that it did have a material impact on DBC for Tariff Year 2014/15. The impact on DBC in the PLEXOS rerun was found to be a 3% reduction. This meant that demand met the criteria for inclusion in the ex-post adjusted model.

3.4. Wind

Actual all-island wind availability was 2% higher than the assumed wind availability in the submitted forecast. This was considered a material difference and a rerun of the PLEXOS model was carried out. This model rerun showed an increase in DBC of 2% when compared with the submitted forecast. A change in actual wind availability alone was therefore not included in the ex-post adjusted model.

3.5. Commercial Offer Data & Modified Interconnector Unit Nominations

Actual Commercial Offer Data (COD) was compared with the submitted 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 in DBC of 8%.

Forecasted Modified Interconnector Unit Nominations (MIUNs) on both Interconnectors were based on historical flows seen on both interconnectors over a number of years. The actual MIUNs however differed significantly on both interconnectors. The main driver for the change was the increase in the Carbon Price Floor in GB from 01/04/2015. This significantly reduced the price spread between SEM and the price in GB, therefore both interconnectors exported more energy from SEM to GB at times. The impact of the actual MIUNs was assessed in PLEXOs and this resulted in a reduction in DBC of 16%.

The actual COD (including actual MIUNs) was considered material and a rerun of the PLEXOS model was carried out. This resulted in a €43 million decrease to DBC which equates to a 23% reduction. As this was greater than the threshold of 3% of the baseline, this update warranted inclusion in the ex-post adjusted model.

3.6. Combination of demand, wind and Commercial Offer Data & MIUNs

When the Plexos model was rerun with the combination of actual demand, actual wind availability and actual COD (including MIUNs) there was a decrease in DBC of €52.6 million (€185 million - €132.4 million) from the baseline (that included model refinements). This equated to a 29% decrease in DBC and met the 8% threshold for inclusion in the ex-post adjusted model, as shown in the summary in Table 4.

Factor	Impact on DBC	Criteria for Inclusion in Ex-Post Adjusted Model	Scenario Included in Ex-Post Adjusted Model
Changes in Demand Forecast	-3%	± 3%	Yes (included in combination scenario below)
Changes in Wind	2%	± 3%	No (but included in combination scenario below)
Changes in Exchange rates/Fuel prices (including MIUNs)	23%	± 3%	Yes (included in combination scenario below)
Changes in Demand Forecast, Exchange rates/Fuel prices (including MIUNs) and Wind	29%	± 8%	Yes

Table 4: Summary of factors checked against the ex-post adjustment inclusion criteria.

3.7. High Impact Low Probability (HILP) events

Transmission outages, both forced outages and scheduled outage overruns, were assessed by the TSO for the Tariff Year 2014/15. Generator forced outages, scheduled outage overruns and generator issues were also examined. The combination of the generation and transmission outages did not meet 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, as shown in Table 5.

HILP	Impact on DBC	Criteria for Inclusion in Ex-post Adjusted Model	Scenario Included in Ex-post Adjusted Model
Combination of Generator Outages, Generator Issue and Transmission Outages	<1%	± 5%	No

Table 5: Summary of HILPs checked against the ex-post adjustment inclusion criteria.

4. Ex-Post Adjustment Results

This section contains a comparison of the submitted forecast and the ex-post adjusted baseline for the Tariff Year 2014/15. A summary of the comparison is outlined in Table 6. There was a €52.6 million (€185 million - €132.4 million) decrease in the PLEXOS component and a €33.1 million decrease in the total constraints component from the submitted forecast to the ex-post adjusted baseline. The results of the ex-post adjusted PLEXOS model and the supplementary modelling are outlined in Sections 4.1 and 4.2 respectively.

Component	Submitted Forecast (€m)	*Ex-Post* Adjusted Baseline (€m)
PLEXOS	**€181.5**	**€132.4**
Supplementary Modelling	**-€3.9**	**€13.5**
Total Constraint Costs	**€177.6**	**€145.9**

Table 6: Summary of submitted forecast compared with the *ex-post* adjusted baseline.

4.1. PLEXOS results

The PLEXOS modelled component of the ex-post adjusted baseline for Tariff Year 2014/15 was found to be **€132.4 million**. This PLEXOS portion of the forecast has decreased from the submitted forecast costs of €181.5 million. The impacts of the ex-post adjusted changes on the original submitted forecast are outlined in Figure 2 below.

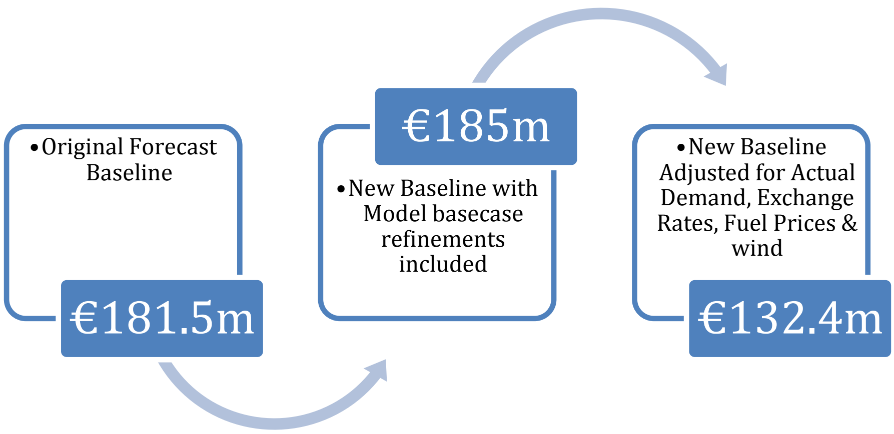

Figure 2: Flowchart of the sequence of calculations made in the ex-post adjustment process.

The changes to DBC as calculated by the PLEXOS model resulted from both model basecase refinements and actual data changes and are outlined in Table 7.

<u>Model basecase refinements:</u>

- The combination of the model refinements, outlined in Section 3.1, included in the ex-post adjusted model resulted in an increase of €3.5 million.

<u>Actual data changes:</u>

- Combination of actual demand, wind, COD (including MIUNs) met the criteria of 8% for inclusion in the ex-post adjusted baseline.

Component	DBC (€m)
PLEXOS component of submitted forecast	**€181.5**
Model basecase refinements	**€185.0**
Combination of actual demand, wind, COD (including MIUNs)	**-€52.6**

Table 7: The impact of the ex-post adjustments on the DBC baseline.

4.2. Supplementary modelling results

The supplementary modelling takes account of the specific external factors that cannot be captured by the PLEXOS model. The ex-post adjusted baseline of the constraints modelled by supplementary modelling for the Tariff Year 2014/15 was €13.5 million. This represents an increase of €17.4 million from the submitted forecast. The results of the supplementary modelling process are summarised in Table 8.

Description		Forecast (€m)	Ex-Post Adjusted (€m)	Change (€m)
Perfect Foresight Effects	Changes to demand and generator availability	6.4	6.4	*0.0*
	Wind predictability	8.6	8.2	*-0.4*
	Long Start-Up and Notice Times	2.7	1.5	*-1.2*
	Interconnector schedule set D-1	0.0	0.0	*0.0*
Specific Reserve Constraints	Turlough Hill	4.9	5.6	*+0.7*
Market Modelling Assumptions	Block Loading	0.7	0.9	*+0.2*
	Hydro limitations & issues	0.0	0.0	*0.0*
System Security constraints	Capacity Testing & Performance Monitoring	0.8	0.8	*0.0*
Non-firm Wind Curtailment	Reduced cost to DBC of curtailing non-firm wind generation	-1.2	-1.4	*-0.2*
System Operator Interconnector Trades – Frequency Service		0.3	0.0	*-0.3*
System Operator Interconnector Trades - Countertrading		-27.0	*-8.6*	*+18.4*
Modelling Total		**-3.9**	**13.5**	***+17.4***

Table 8: The results of the ex-post supplementary modelling process.

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

- **Lower Perfect Foresight Effects:** Lower average System Marginal Price (SMP) in the unconstrained model resulted in a reduction in the cost of some of the Perfect Foresight provisions;
- **Long Start-Up and Notice Times:** The COD for the unit used in this calculation reduced significantly during the tariff year due to the reduction in wholesale fuel prices;
- **Specific Reserve Constraints:** This provision takes account of the reduced efficiency of operation of Turlough Hill in certain modes which cannot be modelled in PLEXOS. 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. An increase in the average actual daytime SMP resulted in an increase in this provision;
- **Market Modelling Assumptions:** There was a small increase in the Block Loading provision. An increase in the average actual daytime SMP resulted in an increase in this provision;
- **Capacity Testing and Performance Monitoring:** There was no overall change in this provision;
- **Wind with non-firm access:** This provision reduces the forecast constraint costs in the supplementary modelling. This reduction offsets the forecast constraint costs over-estimated by the PLEXOS model, which does not differentiate between wind generation units with firm and non-firm access when wind is dispatched down. This provision increased by €0.2m due to slightly higher curtailment in the ex-post adjusted model;
- **System Operator Interconnector Trades:** The original provision for SO interconnector countertrading was -€27 million. This original provision included an estimation for:
  - The revenue received for Priority Dispatch[10] countertrading;
  - The revenue received for Reserve Co-Optimisation countertrading; and
  - The production cost savings for Reserve Co-Optimisation countertrading.

  As outlined in Section 3.1.1 the basecase model was amended to allow PLEXOs to calculate the production cost savings associated with Reserve Co-Optimisation countertrading from 03/03/2015 to 30/09/2015, thus allowing the TSOs gain the full twelve months benefit. The actual countertrading revenue received as part of DBC cannot be broken down to the constituent parts associated with Priority Dispatch and Reserve Co-Optimisation. The TSOs have therefore made the assumption that any countertrading which takes place during the night (23:00 to 08:00) and where the System Non-Synchronous Penetration (SNSP) is greater than 40% is as a result of Priority Dispatch. Using this approach gives the following estimates:
  - Priority Dispatch revenue: €5.5 (for the full 2014/15 tariff year); and
  - Reserve Co-Optimisation revenue: €3.1 (03/03/2015 to 30/09/2015).

  It should be noted that due to the increase in the Carbon Price Floor in GB on 01/04/2015 that the imports on EWIC from GB to SEM decreased significantly, therefore countertrading for reserve co-optimisation was lower following this date.

[10] The production cost savings associated with Priority Dispatch countertrading was included in the original PLEXOs model

5. Incentive Results and Conclusions

For the Tariff Year 2014/15, the ex-post adjusted baseline was €145.9 million. Based on this ex-post adjusted baseline, the dead-band range for which no incentive payment is due is between €134.9 million and €145.9 million. If Imperfections Costs were greater than €156.8 million the penalty would be 5% for every 2.5% of the deficit and if Imperfections Costs were less than €134.9 million, the incentive payment would be 10% for every 2.5% of the surplus, with the payments being capped at €1.8 million.

The outturn imperfections costs were €128.7 million as outlined in Table 9. Note that during the 2014/15 the TSOs raised two SEM Settlement Disputes as follows:

1. **SEM Dispute #1:** When a generating unit is under test in the SEM it can increase Imperfection costs as additional units are constrained on/up for system security reasons. The SEM Testing Tariff is designed to help recover some of the additional costs associated with this testing. An incorrect SEM Testing Tariff was applied in the SEM settlement systems for periods during the 2014/15 tariff year. The TSOs identified this and raised a formal settlement dispute. This was resettled outside of the normal SEM settlement process, however the cost associated with this testing would have increased DBC. As this is an accounting issue the TSOs have included this as a separate line item;
2. **SEM Dispute #2:** The SEM systems assign Market Scheduled Quantities (MSQ) to the maximum of a generating units Firm Access Quantity (FAQ) or Dispatch Quantity (DQ). An incorrect FAQ was issued to a new generating unit for a period during the 2014/15 tariff year. The TSOs identified this and raised a formal settlement dispute. This was resettled outside of the normal SEM settlement process. As this is an accounting issue the TSOs have included this as a separate line item.

Component	Actual Outturn (€m)
Dispatch Balancing Costs	**€140.6**
Energy Imbalance	**-€3.5**
Other System Charges	**-€6.2**
SEM Dispute #1	**-€1.8**
SEM Dispute #2	**-€0.4**
Total Imperfections Costs	**€128.7**

Table 9: 2014/15 Outturn Imperfection Costs

The actual Imperfections cost outturn of €128.7 million is **€17.2 million** lower than the ex-post adjusted baseline. Extrapolating between 10.0% and 12.5% under budget equates to an incentive payment of €0.63 million, as illustrated in Table 10.

Under Budget (%)	Outturn (€)	Under Budget (€)	Incentive Payment (€)
2.5%	142,252,500	3,647,500	None
5.0%	138,605,000	7,295,000	None
7.5%	134,957,500	10,942,500	0
10.0%	131,310,000	14,590,000	364,750
12.5%	127,662,500	18,237,500	729,500
15.0%	124,015,000	21,885,000	1,094,250
17.5%	120,367,500	25,532,500	1,459,000
20.0%	116,720,000	29,180,000	1,823,750
22.5%	113,072,500	32,827,500	1,823,750
25.0%	109,425,000	36,475,000	1,823,750
27.5%	105,777,500	40,122,500	1,823,750

Table 10: Method of calculating the incentive payment with ex-post adjusted baseline.

The level of saving to the DBC budget represents the significant effort on behalf of the TSOs to reduce DBC where possible. A list of the primary operational initiatives introduced by the TSOs which helped to decrease DBC were as follows:

1. **Dublin Must Run**: This refers to the change in the operational constraint of requiring 3 units by night/2 units by day in Dublin. As noted in Section 3.1.1 the TSOs needed to account for the full 12 month benefit of this initiative introduced in the 2013/14 tariff year. The model therefore only applied the new operational constraint rules from 25/10/2014;
2. **Reserve Co-Optimisation Countertrading**: As noted in Section 3.1.1 the TSOs needed to account for the full 12 month benefit of this initiative introduced in the 2013/14 tariff year. The model therefore only applied the new operational constraint rules from 03/03/2015;
3. **Dublin Load Based Constraint Rule:** PBC was removed as a temporary must run on 13/10/2014. This necessitated the introduction of a new load based constraint rule to help manage system contingencies in Dublin. A new load based operational constraint was therefore introduced on 18/11/2014 which required HNC to be run for system loads over 3,800 MW and PBC over 4,400 MW. This new constraint rule helped reduce DBC as the generation was only dispatched when the contingency becomes binding. Note that the load based constraint rule for PBC was further refined from 4,400 MW to 4,600 MW on 04/02/2015 following operational experience;
4. **North – South Total Transfer Capacity:** A change was made to the scheduling software used by the TSOs on 15/11/2014 which 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;
5. **Short Circuit Tool:** A bespoke Short Circuit Tool was introduced into the National Control Centre as part of the existing Energy Management System (EMS). This new tool, which went live on 16/06/2015, allows for studies to be carried out on the network topology whilst allowing the generation dispatch to be optimised. The major benefit of the introduction of this tool was that it

facilitated the TSOs to be able to couple Shellybanks 220 kV station at various times during the tariff year. This allowed the TSOs to dispatch cheaper generation in the Dublin region whereas previously more expensive generation was made must run.

In summary the TSOs have continued to introduce a significant number of operational initiatives to help reduce DBC and therefore the cost to the all-island consumer. Since the introduction of the incentive process the TSOs, through the introduction of operational initiatives have reduced Imperfection Costs (excluding Make Whole Payments) by €73 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m). These savings are not only realised in the year in question but are realised in following years as they become the normal operational standard.

Appendix 1: PLEXOS Modelling and Assumptions

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

The Transmission Network

These are the lines, cables and transformers operated by SONI and EirGrid. PLEXOS allows for the addition of new equipment, decommissioning of old equipment, up-ratings and periods when items are taken out of service.

Generation

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

Demand

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

Fuel Prices

Fuel prices for 2014/15 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters Eikon[11] and data gathered by the TSOs. Carbon costs are also forecast and used, along with fuel costs, to simulate bids.

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

General

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Study period	The study period is 1st October 2014 to 30th September 2015.	N/A
Data Freeze	The input data for the PLEXOS model was frozen on 27th March 2014.	N/A
Generation Dispatch	Two hourly generation schedules are examined: one schedule to represent the dispatch quantities (constrained) and the other to represent the market schedule quantities (unconstrained).	No change

[11] https://thomsonreuterseikon.com/

Study resolution	Each day consists of 24 trading periods, each 1 hour long. A 6 hour optimisation time horizon beyond the end of the trading day is used to avoid edge effects between trading days.	No change
PLEXOS Version	6.301 R02	6.4
Model Reference	Unconstrained: DBC 1415 UC v1.0 Constrained: DBC 1415 v1.0	Unconstrained: DBC 1415 UC v2.0 Constrained: DBC1415 C v2.0

Demand

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Regional Load	NI total load and IE non-industrial load are represented using individual hourly load profiles for each jurisdiction. Both profiles are at the generated exported level and include transmission and distribution losses and demand to be met by wind. The IE profile is net of industrial load.	Actual demand in combination with other factors met the criteria for inclusion in the ex-post adjusted model.
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.	No change
Industrial Demand Data (Ireland)	Industrial loads are generally constant over the day, though some loads change between day and night hours. Rather than following the system demand profile, they are modelled explicitly as purchasers in PLEXOS with a constant load.	No change
Generator House Loads	These are accounted for implicitly by entering all generator data in exported terms.	No change

Generation

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Generation Resources	Conventional generation resources are based on the All-island Generation Capacity Statement 2014-2023. Historical analysis on generators' declared availability was carried out and some units seasonal ratings were adjusted based on this.	Actual wind availability in combination with other factors met the criteria for inclusion in the ex-post adjusted model. The actual commercial and technical parameters were used for GI4 in addition to its commercial operational date in refined model basecase. New Demand Side Units (DSUs) also included in refined model basecase.
Production Costs	Calculated through Plexos using the Regulatory Authorities' publicly available dataset: 2013-14 Validated SEM Generator Data Parameters - Public. Certain changes have been made to this dataset where necessary. • Fuel cost (€/GJ) – forecasted for 2014 and 2015 from Thomson Reuters • Piecewise linear heat rates (GJ/MWh) • No Load rate (GJ/h) • Start energies (GJ) • Variable Operation & Maintenance Costs (€/MWh) A fixed element of start-up costs is calculated based on historical analysis of commercial offer data. The cost of European Union Allowances (EUAs) for carbon under the EU Emissions Trading Scheme (EU-ETS) are taken from ICE EUA Carbon Futures index.	Actual exchange rates, fuel prices and MIUNs were included in the ex-post adjusted model.
Generation Constraints (TOD)	Based on the data in the 2013-14 Validated SEM Generator Data Parameters, the following technical characteristics are implemented: • Maximum Capacity	No change.

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	• Minimum Stable Generation • Minimum up/down times • Ramp up/down limits • Cooling Boundary Times Changes to these parameters have been made where necessary to reflect approved Technical Offer Data (TOD) in the SEM market systems.	
Scheduled Outages	Draft outage schedules are used for 2014 and 2015 maintenance outages.	No change
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates and Mean Times to Repair are based on EirGrid/SONI forecasts and historical data.	No change
Hydro Generation	Hydro units are modelled using daily energy limits. Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled.	No change
Wind Generation	Wind generation resources are based on MW currently installed plus an anticipated rate of connection based on the All Island Renewable Connection Report 36 Month Forecast (Q2 2013)[12].	Actual wind availability was included in the ex-post adjusted model.
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,540MWh. The efficiency of the unit is 70%. It is assumed that the units are all operational by start of study period.	No change
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.	No change
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.	No change
Multi-Fuel Modelling	Only one fuel is modelled for each generating unit. The coal units at Kilroot, while able to run on oil, almost never do so, and will be modelled as coal only.	No change

[12] http://www.eirgrid.com/media/All%20Island%20Renewable%20Connection%20Report%20-%2036%20Month%20Forecast%20(Q3%202012).pdf

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast to be predominantly imports into SEM. This reflects historical experience of flows on both interconnectors prior to the Data Freeze and is a best estimate of likely future flows.	Actual MIUNs were included in the ex-post adjusted model. The interconnector limits also needed to be refined in the basecase model to facilitate the new flows.

Transmission

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Transmission data	The transmission system input to the model is based on data held by the TSOs.	No change
Transmission Constraints	The Transmission system is only represented in the constrained model. The market schedule run is free of Transmission constraints.	No change
Network Load Flow	A DC linear network model is implemented.	No change
Ratings	Ratings for all transmission plant are based on figures from the Planet database and those provided by SONI. Comparisons have been made against the Protection network database and changes have been made where appropriate.	No change
Tie-Line	The North-South tie-line is not represented in the unconstrained model. The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 300MW N-S and 200MW S-N.	No change
Interconnection	The Moyle Interconnector and EWIC are modelled.	No change
Forced Outages	No forced outages are modelled on the transmission network.	No change
Scheduled Outages	Major transmission outages are modelled.	No change

Ancillary Services

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Operating reserve	Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled. Negative Reserve at night of 100MW in IE and 50MW in NI is modelled.	No change
Reserve characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.	No change
Reserve sharing	Minimum reserve requirements are applied to each jurisdiction, with the remainder being shared. These requirements are per the current reserve policy at the time of the data freeze[13].	No change
Static sources	Static reserve provided by STAR (an interruptible load scheme) is modelled. It is assumed that 45MW of static reserve is available from 07:00 to 00:00. An overall maximum limit of 100MW of static reserve from Interconnection is modelled.	No change

[13] http://www.eirgrid.com/media/Operational%20Constraints%20Update%20Version%201%205.pdf