Imperfections Cost Incentive

For Tariff Year 2015/16

31/03/2017

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 €83 million as follows:

- 2012/13 €3 million
- 2013/14 €52.4 million
- 2014/15 €17.2 million
- 2015/16 €10.5 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 2015/16 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 2015/16 were €109.4 million; €10.47 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) further focus on must-run generation constraints in Dublin, the North to South Total Transfer Capacity (TTC) constraint and Dublin generation rule changes.

The savings made by the TSOs during Tariff Year 2015/16 meet the requirements for receiving an incentive payment of €0.148m.

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 01/10/2015 to 30/09/2016 inclusive, referred to as the Tariff Year 2015/16. 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 €83 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m). 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 €163.5 million. This was updated with actual data that met the criteria for inclusion, to form the ex-post adjusted baseline of €119.9 million. This was compared with the outturn Imperfections Costs for Tariff Year 2015/16 to ascertain whether an incentive or penalty payment was due.

The outturn Imperfections Costs were €109.4 million, €10.5 million lower than the ex-post adjusted baseline. These savings are a result of the measures implemented by the TSOs during the Tariff Years 2014/15 and 2015/16. The results of the incentive process are set out in Figure 1.

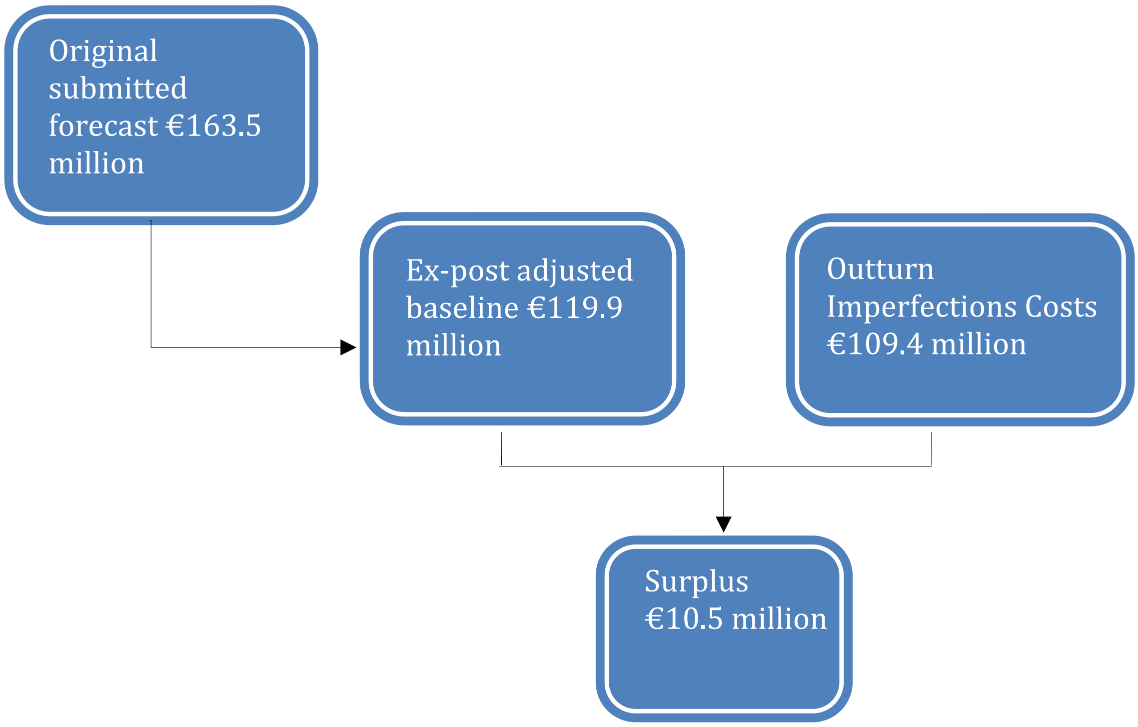

Figure 1: Flowchart of the results of the incentive process.

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[1]. 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 2015/16 was €163.5 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[2].

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

[1] Decision Paper on Incentivisation SEM-12-033
[2] 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[3]	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.

[3] 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[4].
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[5]. • 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[6].
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[7].

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

[4] 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.

[5] 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.

[6] 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.

[7] 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 2015/16. 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 2015/16 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 2014/15

The TSOs introduced a number of operational initiatives at various points in the 2014/15 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[8] of the initiatives outlined as follows:

1. **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.

2. **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 night/three by day was used until July 2016 and the new load based rules were used thereafter.

3.1.2. New Generating Units

1. **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 2015/16 tariff year.

3.1.3. North South Net Transfer Capacity (NTC)

The Operational Constraints outlines how the Total Transfer Capacity (TTC) from North to South cannot exceed 450 MW while the South to North value cannot exceed 400 MW. Plexos requires a static value called the Net Transfer Capacity (NTC) to be inputted for the model to solve. This NTC value should account for any rescue flows that could materialise if a generating unit was to trip in either jurisdiction. In the original Plexos

[8] 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.

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 (TTC) including rescue flows is not breached. This is heavily influenced by transmission outages, the level of wind generation in either jurisdiction, the regional location of the wind and where other generation is being sourced. Typically restrictions in the NTC are to flows in the direction of South to North.

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 therefore 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.

This amendment was included in the ex-post adjustment process.

3.1.4. Generator Technical Offer Data (TOD)

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.

3.1.5. 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.

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 30/04/2015 and the end of the period in question. There were no changes to the SEM rules or RA rule changes which impacted on the 2015/16 process.

3.3. Demand

The actual average monthly demand for Ireland was found to be 3% lower than forecast while that of Northern Ireland in line with the forecast. The Plexos check of actual demand alone indicated that it did have a material impact on DBC for Tariff Year 2015/16. The impact on DBC in the PLEXOS rerun was found to be a 6.5% 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 in line with the assumed wind availability in the submitted forecast. The PLEXOS check of actual wind alone indicated that it did not have a material impact on DBC for Tariff Year 2015/16. The impact on DBC in the PLEXOS rerun was found to be less than 2% reduction. 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 34%.

When the original 2015/16 forecast was submitted flows on both interconnectors were predominantly imports to SEM prior to the data freeze. From 01/04/2015 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 level of exports into GB increased during the night from this date. Actual Interconnector flows for 15/16 were updated as these differed significantly than the forecasted flows. The impact of the actual MIUNs was assessed in PLEXOs and this resulted in a reduction in 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. 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 €81.3 million (€187 million - €105.7 million) from the baseline (that included model refinements). This equated to a 43% 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	-6.5%	± 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)	-38%	± 3%	Yes (included in combination scenario below)

Changes in Demand Forecast, Exchange rates/Fuel prices (including MIUNs) and Wind	-43%	± 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 2015/16. 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 2015/16. A summary of the comparison is outlined in Table 6. There was a €81.27 million (€187 million - €105.73 million) decrease in the PLEXOS component and a €46.67 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	**€152.4**	**€105.73**
Supplementary Modelling	**€11.1**	**€14.13**
Total Constraint Costs	**€163.5**	**€119.86**

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 2015/16 was found to be **€105.73 million**. This PLEXOS portion of the forecast has decreased from the submitted forecast costs of €152.4 million. The impacts of the ex-post adjusted changes on the original submitted forecast are outlined in Figure 2 below.

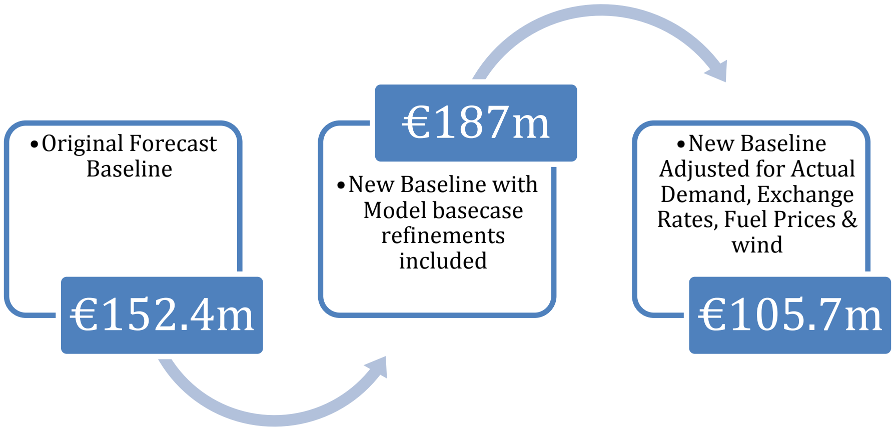

Figure 2: Flowchart of the sequence of calculations made in the ex-post adjustment process.

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 €34.6 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	**€152.4**
Model basecase refinements	**€187.0**
Combination of actual demand, wind, COD (including MIUNs)	**-€81.3**

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 2015/16 was €14.3 million. This represents an increase of €3.03 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	6.3	4.59	*-1.7*
	Wind predictability	9.9	7.28	*-2.6*
	Long Start-Up and Notice Times	1.7	1.26	*-0.5*
Specific Reserve Constraints	Turlough Hill	5.2	4.21	*-0.94*
Market Modelling Assumptions	Block Loading	1.1	0.57	*-0.5*
	Hydro limitations & issues	0.0	0.0	*0.0*
System Security constraints	Capacity Testing & Performance Monitoring	1.1	1.10	*0.0*
Non-firm Wind Curtailment	Reduced cost to DBC of curtailing non-firm wind generation	-2.3	-1.37	*+0.93*
System Operator Interconnector Trades – Frequency Service		0.3	0.0	*-0.25*
System Operator Interconnector Trades - Countertrading		-12.1	*-3.5*	*+8.57*
Modelling Total		**11.1**	**14.13**	***+3.03***

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. A decrease in the average actual daytime SMP resulted in an decrease in this provision;
- **Market Modelling Assumptions:** There was a decrease in the Block Loading provision. An decrease in the average actual daytime SMP resulted in an decrease 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 decreased by €0.93m due to lower curtailment in the ex-post adjusted model;
- **System Operator Interconnector Trades:** The original provision for SO interconnector countertrading for priority dispatch[9] and export limitations was -€12.1 million. This provision decreased by €8.57 million to -€3.5 million in the ex-post adjusted model. -€3.5m was the value for countertrading due to priority dispatch. The allowance for interconnector trades due to export limitations was removed from the ex-post adjusted budget as the restriction is deemed to be within the control of the TSOs.

5. Incentive Results and Conclusions

For the Tariff Year 2015/16, the ex-post adjusted baseline was €119.9 million. Based on this ex-post adjusted baseline, the dead-band range for which no incentive payment is due is between €110.9 million and €116.9 million. If Imperfections Costs were greater than €131.8 million the penalty would be 5% for every 2.5% of the deficit and if Imperfections Costs were less than €110.9 million, the incentive payment would be 10% for every 2.5% of the surplus, with the payments being capped at €1.5 million.

The outturn imperfections costs were €109.4 million as outlined in Table 9.

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

Table 9: 2015/16 Outturn Imperfection Costs

The actual Imperfections cost outturn of €109.4 million is **€10.5 million** lower than the ex-post adjusted baseline. Extrapolating between 7.5% and 10.0% under budget equates to an incentive payment of €0.15 million, as illustrated in Table 10.

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

Under Budget (%)	Outturn (€)	Under Budget (€)	Incentive Payment (€)
2.5%	116,871,198	2,996,697	None
5.0%	113,874,501	5,993,395	None
7.5%	110,877,804	8,990,092	0
10.0%	107,881,106	11,986,790	299,670
12.5%	104,884,409	14,983,487	599,339
15.0%	101,887,711	17,980,184	899,009
17.5%	98,891,014	20,976,882	1,198,679
20.0%	95,894,317	23,973,579	1,498,349
22.5%	92,897,619	26,970,277	None
25.0%	89,900,922	29,966,974	None
27.5%	86,904,224	32,963,671	None

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. 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 to 25/10/2015;
2. **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. This software was further refined in June 2016 to increase the amount of reserve that was available in Northern Ireland if a generator tripped in this jurisdiction. This at times helped to increase the flows that could flow 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. The system stability requirements were also changed.

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 €83 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m). 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 2015/16 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters[10] and HEREN[11] reports and information available from the ICE futures website[12]. Carbon costs are also forecast and used, along with fuel costs, to simulate bids for generators and interconnector units in SEM and BETTA. These are then input to PLEXOS to simulate participant commercial offer data for each unit.

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 2015to 30th September 2016.	N/A
Data Freeze	The input data for the PLEXOS model was frozen on 30th April 2015.	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

[10] http://thomsonreuters.com/products_services/financial/financial_products/commodities/energy/
[11] http://www.icis.com/heren/
[12] https://www.theice.com/homepage.jhtml

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	6.302 R02	No Change
Model Reference	Unconstrained: DBC 1516 UC v1.0 Constrained: DBC 1516 v1.0	Unconstrained: DBC 1516 v2.0 UC Constrained: DBC1516 v2.0 Con

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 2015-2024. 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. 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[13]. A draft version of the 2015/16 Validated SEM Generator Data Parameters was obtained prior to the data freeze. Any parameters which changed by greater than 10% were updated in the model. Minor changes have been made to this dataset where necessary to reflect Commercial Offer Data (COD) in the SEM systems. 1. Fuel cost (€/GJ) – forecasted for 2015/16 from Thomson Reuters 2. Piecewise linear heat rates (GJ/MWh) 3. No Load rate (GJ/h) 4. Start energies (GJ) 5. 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[25], the following technical characteristics are implemented: 1. Maximum Capacity 2. Minimum Stable Generation 3. Minimum up/down times	Reduction to Generator minimum loads were applied to the refined basecase model.

[13] http://www.allislandproject.org/en/market_decision_documents.aspx?article=862948e4-e60f-40e6-b876-d1a34d1c496c

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	4. Ramp up/down limits 5. Cooling Boundary Times A draft version of the 2015/16 Validated SEM Generator Data Parameters was obtained prior to the data freeze. Any parameters which changed by greater than 10% were updated in the model. Changes to these parameters have been made where necessary to reflect approved Technical Offer Data (TOD) in the SEM market systems. The capping of the Maximum Generation based on the contracted Maximum Export Capacity (MEC) in Ireland per the CER Decision[14] was not implemented due to this decision being deferred.	
Scheduled Outages	Draft outage schedules are used for 2015and 2016 maintenance outages.	No change
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates are based on EirGrid/SONI forecasts and Mean Times to Repair information is based on the 2013-14 Validated SEM Generator Data Parameters. A draft version of the 2015/16 Validated SEM Generator Data Parameters was obtained prior to the data freeze. Any parameters which changed by greater than 10% were updated in the model.	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 (Q4 2013)[15]. This is based on 1965 MW already installed in Ireland and 629 MW in Northern Ireland. Between 1st October 2014 and 30th September 2016 there is 1338 MW of wind contracted to connect. Based on the All Island Renewable Connection Report 36 Month Forecast, a medium All-Island rate of	Actual wind availability was included in the ex-post adjusted model.

[14] CER/14/047 – Decision on Installed Capacity Cap
[15] http://www.eirgrid.com/media/All_Island_Renewable_Connection_Report_36_Month_Forecast__(Q4_2013).pdf

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	connection based on the last 3 year's rate is ~415 MW/Year. The contracted wind is then scaled by 62% (830 MW / 1338 MW) at each of the transmission nodes to give a more reasonable estimate of wind connections.	
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,540MWh. The efficiency of the unit is 70%.	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.	New demand side units were updated in the basecase model.
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. Note that where units are multi fuel start this is modelled explicitly using one fuel offtake for each fuel. Multi fuel start units are Kilroot units one and two, Moneypoint units one, two and three and Tarbert units one, two, three and four.	No change
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast to be predominantly imports into SEM and exports into GB during the night. 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.

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	No change

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	schedule run is free of Transmission constraints.	
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 300MW S-N.	A revised hourly NTC value is included in the constrained Plexos model for flows in the direction of South to North. This is based on the actual TTC used by Real Time
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[16].	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. From 07:00 – 16:30, 17:00 – 18:30 and 19:00 – 23:30 the STAR provision is reduced to 17 MW, 12 MW and 17 MW respectively between the 24/12/2015 and 01/01/2016. Static reserve will be available on Moyle if there is sufficient unused capacity available, up to a maximum of 49 MW in Northern Ireland (the reserve is 50 MW, however this is measured in Great Britain). Static reserve will be available on EWIC if there is sufficient unused capacity available, up to a maximum of 70 MW in Ireland (the reserve is 75 MW, however this is measured in Great Britain). An overall maximum limit of 150MW of static reserve from Interconnection is modelled, as measured in Great Britain. Note that during outages of EWIC it is assumed that 49 MW of additional static reserve will be available on Moyle i.e. up to 98 MW of static reserve from Moyle (as measured in Northern Ireland).	STAR reserve values were updated in line with the operational constraint documents. 49MW of static reserve from 01/10/2015 – 20/10/2015. 58MW of static reserve from 21/10/2015 – 23/12/2015. 20MW from 24/12/2015 – 02/01/2016. 43MW from 03/01/2016-30/09/2016

[16] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_24_April_2015.pdf