# Imperfections Cost Incentive

## For Tariff Year 2016/17

10/05/2018

# 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 €98.4 million as follows:

- 2012/13 €3 million
- 2013/14 €52.4 million
- 2014/15 €17.2 million
- 2015/16 €10.5 million
- 2016/17 €15.3 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 2016/17 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. As part of the ex-post adjustment process, various elements were considered material (see Section 3.1), including general refinements to the model and actual data changes.

The outturn Imperfections Costs incurred over the Tariff Year 2016/17 were €126.9 million; €15.3 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 not limited to): increases in System Non Synchronous Penetration (SNSP); implementation of Special Protection Schemes (SPS) and Dublin Generation Rules changes.

The savings made by the TSOs during Tariff Year 2016/17 meet the requirements for receiving an incentive payment of €0.46 million.

# 1. Introduction

This submission to the Commission for Regulation of Utilities (CRU) & 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 01/10/2016 to 30/09/2017 inclusive, referred to as the Tariff Year 2016/17. 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 €98.4 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m, 2016/17: €15.3). 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 €144.3 million. This was updated with actual data that met the criteria for inclusion, to form the ex-post adjusted baseline of €142.2 million. This was compared with the outturn Imperfections Costs for Tariff Year 2016/17 to ascertain whether an incentive or penalty payment was due.

The outturn Imperfections Costs were €126.9 million, €15.3 million lower than the ex-post adjusted baseline. These savings are a result of the measures implemented by the TSOs during the Tariff Years 2015/16 and 2016/17. The results of the incentive process are set out in Figure 1.

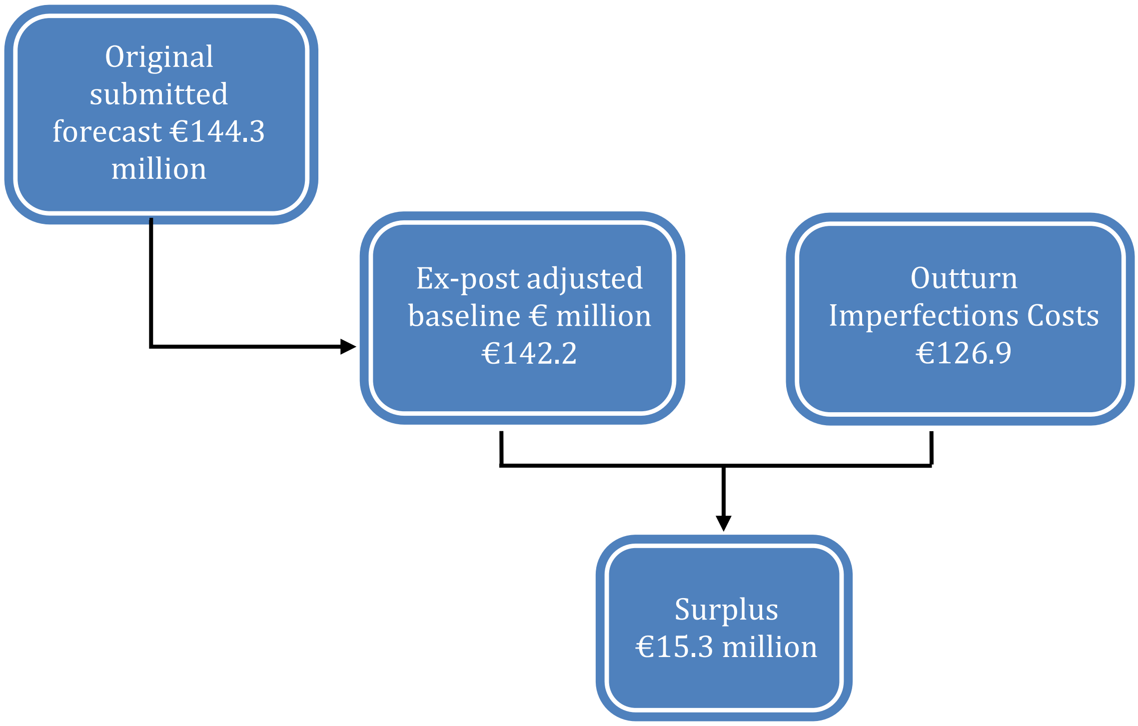


**Figure 1: Flowchart of the results of the incentive process.**

# 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 2016/17 was €144.3 million.

To allow participants to understand the material cost drivers and the impact Imperfections Costs have 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, as set out in SEM-12-033, are listed 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. |

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

| | | |
|---|---|---|
| **SO Trades** | Yes | For system security and priority dispatch, the TSOs can 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 because failure to provide necessary services to the system leads 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.

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

## 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.

| 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.<br>Or<br>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.<br>• 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].<br>• 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.<br>• 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 2016/17. 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 adjustments

During the ex-post review process three refinements were required to the original 2016/17 forecast PLEXOS model to ensure a more accurate and robust base case on which to measure the qualifying criteria. The refinements are as follows:

### 3.1.1. Initiatives introduced in 2015/16

The TSOs introduced a number of operational initiatives at various points in the 2015/16 tariff year and these helped to reduce DBC by €10.5 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 Load Based Constraints / 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.

2. **SNSP** increased from 50% to 55% on 01/03/2016

### 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 base case model was therefore updated to include all DSUs which became operational during the 2016/17 tariff year.

### 3.1.3. Generator Technical Offer Data (TOD)

A number of units in Dublin reduced their minimum load value during 2016/17 and can now provide operating reserve from a lower value. This helped reduce DBC as the units had been constrained on and the reduction in minimum load helped bring them into merit in the SEM.

[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.

### 3.1.4. Adjustments to PLEXOS Model

1. **Inclusion of Turlough Hill Efficiency in Ex-Post PLEXOS model**

   In previous years and in the 2016/17 submitted forecast Turlough Hill efficiency was included in the supplementary modelling rather than the PLEXOS model. For the 2016/17 ex-post Forecast Turlough Hill efficiency changes have been included in the PLEXOS model, rather than in the supplementary modelling. This is a more accurate representation of the actual efficiency of Turlough Hill.

2. **System Security in Northern Ireland and Moyle Flows**

   The TSO used countertrading on Moyle to mitigate a system security issue. This related to reduced generator availability in Northern Ireland due to a high number of overlapping generator outages from 02/10/2016 - 05/11/2016.

3. **Prolonged Turlough Hill Outage**

   PLEXOS is designed to model normal unit outages, but could not accurately model the impact of the prolonged outage of the Turlough Hill Units from 16/07/2017 - 27/10/2017. As Turlough Hill has such an important role in providing operating reserve, the PLEXOS model was amended to reflect the use of North Wall 5, as a necessary source of system reserve during this outage.

4. **Prolonged and Significant Outages in the South West**

   In 2016/17, there were significant outages in the South-West to facilitate transmission reinforcements. PLEXOS could not adequately model the impact of this and was amended to reflect the requirement to run Tarbert generation for system support, during these outages.

### 3.1.5. Gas Transportation Capacity Charges

The bidding behaviour of Ballylumford in 2016/17, based on them seeking to recover Gas Transportation Capacity charges, has resulted in increased constraints costs, where they have been constrained on in dispatch to meet reserve, transmission or security constraints on the power system. Therefore the actual Ballylumford running was included in the ex-post PLEXOS model.

## 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 11/04/2016 and the end of the period in question. There were no changes to the SEM rules or RA rule changes which impacted on the 2016/17 process.

## 3.3. Demand

The actual all-island monthly demand was 0.5% higher than forecast: for Ireland it was 1.1% higher than forecast; for Northern Ireland it was 1.4% lower than forecast. The PLEXOS check of actual demand alone indicated that it did have a material impact on DBC for Tariff Year 2016/17. This resulted in a 6.1% decrease in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included in the ex-post adjusted model.

## 3.4. Available Energy: Wind, Solar, DSU & Peat

Actual all-island wind, solar, DSU & peat availability was higher than the assumed respective availabilities in the submitted forecast.

It was found that the shape of DSU available energy does not have a flat profile but rather varies considerably with time. To more accurately reflect this, the actual DSU available energy was included in the ex-post model.

The PLEXOS check of the combination of these availability changes indicated that it had a material impact on DBC for Tariff Year 2016/17. This resulted in a 15.3% decrease in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included in the ex-post adjusted model.

## 3.5. Commercial Offer Data & Modified Interconnector Unit Nominations (MIUNs)

Actual Commercial Offer Data (COD) was compared with the submitted forecast COD and these differed enough to consider for inclusion. Actual Interconnector flows for 2016/17 were updated as these differed significantly from the forecasted flows. In part, this was due to significant unplanned interconnector outages.

The impact of actual COD, including actual MIUNs, was considered material and a rerun of the PLEXOS model was carried out, to quantify this. This resulted in a 5% decrease in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included 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 an increase in DBC of €37.9 million from the baseline (that included model refinements). This equated to a 26.7% 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** | -6.1% | ± 3% | Yes (included in combination scenario below) |
| **Changes in Available Energy (Wind, Solar, DSU & Peat)** | -15.3% | ± 3% | Yes (included in combination scenario below) |
| **Changes in Exchange Rates/Fuel Prices (including MIUNs)** | -5% | ± 3% | Yes (included in combination scenario below) |
| **Combined impact of changes in Demand Forecast, Exchange Rates/Fuel Prices (including MIUNs) & Wind** | -26.7% | ± 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 2016/17. Generator forced outages, scheduled outage overruns and generator issues were also examined. The combination of the generation and transmission outages met the HILP criteria as they resulted in an increase in DBC of 8.0%.

This was therefore considered material and was 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 Issues and Transmission Outages** | +8.0% | ± 5% | Yes |

**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 2016/17. A summary of the comparison is outlined in Table 6. There was a €5.4 million (€125.8 million - €120.4 million) decrease in the PLEXOS component and a €2.1 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** | **€125.8** | **€120.4** |
| **Supplementary Modelling** | **€18.5** | **€21.8** |
| **Total Constraint Costs** | **€144.3** | **€142.2** |

**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 2016/17 was found to be **€120.4 million**. This PLEXOS portion of the forecast has decreased from the submitted forecast costs of €125.8 million. The impacts of the ex-post adjusted changes on the original submitted forecast are outlined in Figure 2 below.

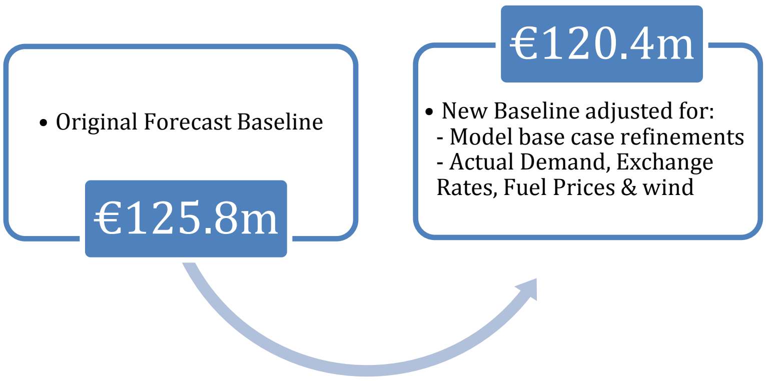


**Figure 2: Ex-post adjustment process.**

The changes to DBC as calculated by the PLEXOS model, which resulted from both model base case refinements and actual data changes, have been outlined in Section 3.1 and summarised in Table 7.

| Component | DBC (€m) |
|---|---|
| **PLEXOS component of submitted forecast** | 125.8 |
| **Net of base case refinements and actual data changes adjustments** | -5.4 |
| **PLEXOS component of Ex-post Adjusted Baseline** | 120.4 |

**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 2016/17 was €21.8 million. This represents an increase of €3.3 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 | 4.9 | 5.46 | *0.56* |
| | Wind predictability | 8.9 | 9.40 | *0.50* |
| | Long Start-Up and Notice Times | 1.2 | 1.97 | *0.77* |
| **Specific Reserve Constraints** | Turlough Hill | 4.4 | 0.0[9] | *-4.4* |
| **Market Modelling Assumptions** | Block Loading | 0.6 | 0.46 | *-0.14* |
| | Hydro limitations & issues | 0.0 | 0.0 | *0.0* |
| **System Security constraints** | Capacity Testing & Performance Monitoring | 1.5 | 1.42 | *-0.08* |
| **Non-firm Wind Curtailment** | Reduced cost to DBC of curtailing non-firm wind generation | -1.5 | -1.73 | *-0.23* |
| **System Operator Interconnector Trades - Frequency Service** | | 0.3 | 0.0 | *-0.3* |
| **System Operator Interconnector Trades - Countertrading** | | -2.6 | *4.21*[10] | *6.81* |
| **Secondary Fuel Start Up Testing** | | 0.8 | *0.62* | *-0.18* |
| **Supplementary Modelling Total** | | **18.5** | **21.8** | ***3.3*** |

**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:

- **Turlough Hill**
  This was moved from supplementary to PLEXOS model in ex-post
- **System Operator Interconnector Trades – Countertrading**
  The TSO used countertrading on Moyle to mitigate a system security issue. This related to reduced generator availability in Northern Ireland due to a high number of overlapping generator outages from 02/10/2016 - 05/11/2016.

[9] Turlough Hill efficiency moved from supplementary modelling to PLEXOS model, refer to Section 3.1.4.
[10] Moyle countertrading flows included in Supplementary on the basis they were included in PLEXOS model, refer to Section 3.1.4

# 5. Incentive Results and Conclusions

For the Tariff Year 2016/17, the ex-post adjusted baseline is €142.2 million.

Based on this ex-post adjusted baseline, the dead-band range for which no incentive payment is due is between €131.5 million and €152.8 million. If Imperfections Costs were greater than €152.8 million the penalty would be 5% for every 2.5% of the deficit and if Imperfections Costs were less than €131.5 million, the incentive payment would be 10% for every 2.5% of the surplus, with the payments being capped at €1.78 million.

The outturn imperfections costs were €126.9 million as outlined in Table 9.

| Component | Actual Outturn (€m) |
|---|---|
| **Dispatch Balancing Costs** | **€127.6** |
| **SO Trades** | **€10.9** |
| **Energy Imbalance** | **-€2.6** |
| **Other System Charges** | **-€9.0** |
| **Total Imperfections Costs** | **€126.9** |

**Table 9: 2016/17 Outturn Imperfection Costs**

The actual Imperfections cost outturn of €126.9 million is **€15.3 million** lower than the ex-post adjusted baseline. Extrapolating between 10% and 12.5% under budget equates to an incentive payment of €0.46 million, as illustrated in Table 10.

| Under Budget (%) | Outturn (€) | Under Budget (€) | Incentive Payment (€) |
|---|---|---|---|
| 2.5% | 138,622,711 | 3,554,428 | None |
| 5.0% | 135,068,282 | 7,108,857 | None |
| 7.5% | 131,513,854 | 10,663,285 | 0 |
| 10.0% | 127,959,425 | 14,217,714 | 355,443 |
| 12.5% | 124,404,997 | 17,772,142 | 710,886 |
| 15.0% | 120,850,568 | 21,326,571 | 1,066,329 |
| 17.5% | 117,296,140 | 24,880,999 | 1,421,771 |
| 20.0% | 113,741,711 | 28,435,428 | 1,777,214 |
| 22.5% | 110,187,283 | 31,989,856 | None |
| 25.0% | 106,632,854 | 35,544,285 | None |
| 27.5% | 103,078,426 | 39,098,713 | 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. **SNSP 55%:** 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. Under the incentive arrangements the TSOs are rewarded for the benefits their initiatives bring for a full year. Therefore the reward for this initiative is scheduled to run until 28/02/2017.

2. **SNSP 60%:** Following a successful trial from November 2016 the Non-Synchronous Generation limit permanently changed from 55% to 60% on 09/03/2017.

3. **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. Under the incentive arrangements the TSOs are rewarded for the benefits their initiatives bring for a full year. Therefore the reward for this initiative is scheduled to run until 23/05/2017.

4. **Special Protection Schemes (SPS):** The implementation of Special Protection Schemes at Clogher and Mount Lucas has helped reduce DBC. New generation connecting at these locations requires significant transmission reinforcements, with long lead times. The TSOs proposed the installation of these SPS to facilitate access to the transmission system for this additional generation, in advance of the deep reinforcements being completed and thereby lowering constraint costs.

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 €98.4 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m, 2016/17: €15.3). 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 2016/17 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters[11] and EIA[12] reports. 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 2016 to 30th September 2017. | N/A |
| Data Freeze | The input data for the PLEXOS model was frozen on 11th April 2016. | 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] http://eikon.thomsonreuters.com/index.html
[12] http://www.eia.gov/forecasts/steo/tables/

| | | |
|---|---|---|
| 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: DBC1617 UC v2.4<br>Constrained: DB1617 C v2.4 5 | Unconstrained: DBC 1617 UC 1<br>Constrained: DBC 1617 C 2 |

### Demand

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| Regional Load | NI total load and IE total 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. | Actual demand in combination with other factors met the criteria for inclusion in the ex-post adjusted model. |
| 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 |
| 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 2016-2025. Historical analysis on generators declared availability was carried out and some units seasonal ratings were adjusted based on this. | Actual wind installed capacity and availability in combination with other factors met the criteria for inclusion in the ex-post adjusted model.<br><br>New Demand Side Units (DSUs) are also included. |
| Production Costs | Calculated through PLEXOS using the Regulatory Authorities' publicly available dataset: 2015-16 Validated SEM Generator | Actual exchange rates, fuel prices and interconnector MIUNs |

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| | Data Parameters[13].<br>1. Fuel cost (€/GJ) – forecasted for 2016/17 from Thomson Reuters<br>2. Piecewise linear heat rates (GJ/MWh)<br>3. No Load rate (GJ/h)<br>4. Start energies (GJ)<br>5. Variable Operation & Maintenance Costs (€/MWh)<br>A fixed element of start-up costs is calculated based on historical analysis of commercial offer data.<br>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. | Were included in the ex-post adjusted model. |
| Generation Constraints (TOD) | Based on the data in the 2015-16 Validated SEM Generator Data Parameters, the following technical characteristics are implemented:<br>1. Maximum Capacity<br>2. Minimum Stable Generation<br>3. Minimum up/down times<br>4. Ramp up/down limits<br>5. Cooling Boundary Times<br>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. | Reduction to generator minimum loads were applied to the model. |
| Scheduled Outages | Draft outage schedules are used for 2016 and 2017 maintenance outages. | Actual outage schedules are used for 2016 and 2017 maintenance outages |
| 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 2016/17 Validated SEM Generator Data Parameters was obtained prior to the | Actual generator outages are included in the model. |

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

[14] CER/14/047 – Decision on Installed Capacity Cap

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| | data freeze. Any parameters which changed by greater than 10% were updated in the model. | |
| Hydro Generation | Hydro units are modelled using daily energy limits.<br>Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled. | Hydro units are modelled using daily energy. |
| Wind Generation | Wind generation resources are based on MW currently installed plus an anticipated rate of connection. | Actual wind availability was included in the ex-post adjusted model. |
| Turlough Hill | Modelled as 4 units of 73 MW.<br>The usable reservoir volume is 1,540MWh.<br>The efficiency of the unit is 70%. | PLEXOS model updated to reflect nominal Turlough Hill efficiency in the Unconstrained Model and actual efficiency in the Constrained Model. See Section 3.1.4 for Turlough Hill modelling. |
| 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 base case 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 | Actual MIUNs were included in the ex-post adjusted model.<br>Moyle - operated on |

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| | flows on both interconnectors prior to the data freeze and is a best estimate of likely future flows. | one pole from 16th Feb – 27th September 2017.<br>EWIC – had a forced 3 month outage at the end of 2016, and a planned outage in 2017 was reduced in duration by one month. |

### Transmission

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| Transmission Data | The transmission system input to the model is based on data published by the TSOs in the Ten Year Transmission Forecast Statement (TYTFS). | 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 TYTFS. | No change |
| Tie-Line | The North-South tie-line is not represented in the unconstrained model.<br>The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 300 MW N-S and 175 MW S-N. | Some minor adjustments were included in the model to reflect the impact of transmission maintenance outages in the local area. |
| Interconnection | The Moyle Interconnector and EWIC are modelled. | Moyle export was set at 300MW until 16th Feb after which it was set at 253MW until 27th September when it returned to 300MW. Moyle import was set at 442MW until 16th Feb. From 16th Feb to 27th Sept it was 253MW when it returned to 440MW. EWIC increased to full export capability. |
| Forced Outages | No forced outages are modelled on the | No change |

| Feature | Forecast Assumptions | Ex-post Adjustment Assumptions |
|---|---|---|
| | transmission network. | |
| 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.<br>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[15]. | No change |
| Static sources | Static reserve provided by STAR (an interruptible load scheme) is modelled. | No change |

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