SEM Committee

Transmission Loss-Adjustment in Commercial Offer Data

General Direction

SEM-08-179

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1. Introduction

The Market Monitoring Unit (MMU) has detected some confusion among market participants surrounding the inclusion of transmission loss adjustments (specifically TLAFs) in the formulation of Generator Unit Commercial Offer Data (COD).

Following this detection, the MMU carried out some research to establish the surrounding issues and subsequently obtained a decision from the SEM Committee (SEMC)[1], around which this General Direction has been drafted.

The Direction is provided in Section 6 of this Paper.

The SEM Committee has determined that this issue is a SEM Committee matter within the meaning of the relevant legislation.

The relevant Licence Conditions under which this Direction is made include:

- Condition 17 of the General Electricity Generation Licence in Northern Ireland; 'Cost-Reflective Bidding in the Single Electricity Market'.

- Section C Condition 15 of the General Electricity Generation Licence in the Republic of Ireland; 'Cost-Reflective Bidding in the Single Electricity Market'.

2. Headline Issue

At present, some Generator Units are making an adjustment to their Commercial Offer Data (be it Prices, Quantities, Start-Up Cost and / or No-Load Cost) to account for the cost of transmission losses, while other Generators are not.

In the MMU's view, this imbalance is driven by a lack of clarity across the relevant Codes as to how Generators are expected to treat the cost associated with transmission of their generated quantities to the Trading Boundary.

The imbalance of present interpretations of the rules is not fair in the view of the SEMC, and is likely to be distorting the efficiency of market outcomes.

For an effective monitoring function, there must be a common basis upon which to assess bidding behaviour. This is accomplished via the standing Bidding Code of Practice (BCOP). To permit the prevailing imbalance across participants' interpretations to continue would, in

[1] The SEM Committee is established in Ireland and Northern Ireland by virtue of section 8A of the Electricity Regulation Act 1999 as inserted by section 4 of the Electricity Regulation(Amendment) Act 2007, and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.

the SEMC's view, fetter the intended goal of the BCOP; which is to stipulate both effective principles, as well as sustain fairness across the competing Generators.

This document sets out clear regulatory policy on how TLAFs are to be treated in formulation of COD. However the Direction necessarily stops short of issuing prescriptive algebra to this effect.

3. Background and Considered Factors

3.1. The Grid Code

The Grid Code stipulates the manner in which COD is to be referred to the Connection Point. The relevant clause is SDC 1.4.4.5. which states:

> SDC1.4.4.5 **Commercial Offer Data**
>
> (a) Each:
> \- **Generator**;
> **- Pumped Storage Generator**;
> **- Interconnector User**;
> **- Dispatchable Demand Customer**; and
> **- Generator Aggregator,**
>
> shall
>
> <snip>
>
> submit to the **TSO**, either directly or by means of an **Intermediary** on its behalf, **Commercial Offer Data** by **Gate Closure** for the following **Trading Day** in accordance with the **TSC.**
>
> <snip>
>
> All data items submitted under this SDC1.4.4.5 are to be at levels of **MW Output** at the **Connection Point**.

While the principles underpinning the commercial behaviour of generators are set out and governed by the regulatory licensing framework, and more specifically the BCOP, and not by the Grid Code, the MMU accept that this section of the Grid Code has the potential to give rise to confusion. The SEMC recognises that the wording of this clause could be construed to refer to two possible instructions:

1. The Quantity aspect of the COD should refer to the Connection Point.

2. All COD, including Quantity, Price, No-Load and Start-Up should refer to the Connection Point.

Hereafter these two interpretations are referred to as ‘GC #1’ and ‘GC #2’.

Under the first interpretation (GC #1), the MW Quantities would be bid in with reference to the quantity of energy that can be delivered at the Connection Point, but treatment of the monetary data points (Price, No-Load and Start-Up) with regard to transmission losses are not explained by the clause.

Under the second interpretation GC #2, bidders would generally be expected to divide all monetary values (those elements of COD measured in Euros or Pounds or their per-unit equivalents) by their (best estimate of) the Generator’s TLAF. The rationale here is that the price of delivering energy to the Trading Boundary is higher than that of delivering it to the Connection Point if the station has a TLAF below 1.0. The converse is true for Generators with TLAFs above 1.0, as the price at the Trading Boundary is lower than the price at the Connection Point. So again the same method of division by the relevant loss adjustor would apply.

The MMU sought advice from the System Operators (SOs) on the intent of this clause. The SOs advised that this would be expected to refer to the MW Quantity. It is the view of the SEMC that if this is the intention, that in the first instance the phrase ‘All data items’ in the clause is misleading. Secondly, on this line of argument (interpretation GC#1) there then remains an open question as to whether the monetary data (everything other than Quantity) should or should not be TLAF adjusted using the division described above.

3.2. The Unit Commitment and Shadow Price Algorithm

The Market Systems algebra does not pre-process COD to adjust for transmission loss factors. This is a key point because it means that:

1. The Unit Commitment algorithm does not feature an implicit loss-adjusted optimisation.

2. The merit order is built from Puh and Quh – unadjusted Prices and Quantities (absence of ‘LF’ notation).

3. Rather, TLAFs are **only** applied at the Settlement step, at which Generator Quantities (MSQs) are adjusted by a multiplier of the TLAF.

If Generators were to adhere to the second interpretation of the Grid Code (GC #2), then

1. The commitment and merit order would be built without reference to transmission loss adjustment.

2. The Shadow Price and SMP would not be a function of loss-adjusted prices.

This would imply that the Trading Boundary is circumvented; as market prices, merit orders and schedules will all be in reference to a notional ‘station gate’. In other words the optimiser would ignore the relative locational favourability of the resources it uses to meet its minimum production cost objective.

This lends weight to the notion that it would be preferable to require Generators to make the loss adjustment to the monetary data themselves (while there is no question that the Quantity element must **not** be loss adjusted).

3.3. The Bidding Code of Practice

It is worth considering whether transmission losses, or more specifically the cost of these losses, are avoidable short-run marginal costs in the classical sense of the BCOP.

Conceptually to paraphrase the BCOP, 'the cost of generating electricity less the cost of not generating electricity' would be expected to feature a positive residual element of revenue above other residuals that reflects the need generate more energy than what is ultimately consumed by the purchaser (suppliers at the Trading Boundary). This would be the expectation for a generator with an 'average' TLAF'. Indeed, the conceptual 'centre of gravity' for TLAFs is below 1.0, reflecting that, on average, when a Generator exports power to the grid, part of it is lost in transit to the Trading Boundary.

The converse holds for Generators whose exported volumes tend to reduce system losses. The difference between 'the cost of generating electricity less the cost of not generating electricity' would feature a residual element of negative revenue due to the benefit the Generator lends the system when generating (i.e. the exported quantity is smaller than the effective quantity sold at the Trading Boundary).

Currently, under the 'GC #2', a Generator with a TLAF less than 1.0, which is scheduled in the market to run at the margin, would receive a lower payment for the energy it provides than the bid it made to the market. For example if the TLAF is 0.98, then there would be a short-run loss of 2% of energy revenue that would simply have to be absorbed by the generation firm.

If the GC#2 were to be enforced, the generation portfolio would thus be expected to absorb the cost of transmission losses as an unavoidable cost. Given the argument above, this notion tends to argue in favour of rejection of the GC#2 as the best interpretation of the Grid Code clause.

4. Complications

It is the SEMC's view that transmission losses are avoidable and are wholly associated with the cost of generating in the sense of the Bidding Principles. Further, the SEMC is of the view that the SMP should be relevant at the Trading Boundary and that the merit order that is used to formulate the Unit Commitment and Scheduling problems should feature corrections that adequately factor in the profile of loss factors across the Generators that make up that merit order. As such, TLAFs should be used to adjust the COD **prior** to the

MSP algorithm constructing a merit order, followed by the subsequent Unit Commitment, Schedule and so on.

It is clear that the market software does **not** in and of itself pre-process any element of COD for TLAFs in formulating the merit order.

Concept For Direction

Thus the SEMC wishes in the first instance to Direct that COD should be transmission loss adjusted by participants, as a final step in the calculation prior to submission to the Market Operator. There are however, complications with this approach which make its implementation difficult.

4.1. Start-Up and No-Load Costs

The cost of delivering electricity to the Trading Boundary includes the cost of starting up the generator unit and the invariant-with-output aspect of the running cost. To explain by means of an example; for two units of identical technical capability at two different locations and the absence of any constraints, one would always choose to first start the unit with the superior transmission loss characteristic (i.e. the unit with the higher TLAF).

Under the intent of Directing participants to loss-adjust their entire monetary COD elements (Prices, Start-Up and No-Load Costs but not MW Quantities), it is worth examining the way that the Start-Up and No-Load are settled and remunerated under the T&SC.

Uplift

The algebra which is used to calculate the Uplift implicitly works from the relevant Market Quantities (Market Price, No-Load and Start-Up). This means that Uplift, and subsequently SMP, are built in step with the Shadow Price; from the same un-modified monetary data points. The loss-normalisation applied to the MSQ of the Generator at Settlement is multiplied through the SMP (not just the Shadow Price).

So by enforcing that Generators loss-adjust **all** monetary data points, then a Generator scheduled at the margin would bid loss-adjusted (TLAF-divided) data and receive a correctly loss-normalised (TLAF-multiplied) payment that remunerates no less than the total production cost (over the Trading Day) in accordance with the objective of the Uplift algorithm.

Constraint and Make-Whole Payments

The formula for calculating the Constraint Payments for a Generator Unit is given by:

$$CONPuh - TPD \times \begin{bmatrix} (DQLFuh \times DOPuh + DNLCuh + DQCCLFuh) \\ -(MSQLFuh \times MOPuh + MNLCuh + MSQCCLFuh) \end{bmatrix} + DSUCuh - MSUCuh$$

The Make-Whole formula is as follows:

$$MWPub = Max\left\{\sum_{h\,in\,b}\left[\begin{pmatrix}(MOPuh - SMPh)\times MSQLFuh \\ + MNLCuh + MSQCCLFuh\end{pmatrix}\times TPD + MSUCuh\right], 0\right\}$$

These equations clearly show that, when a Constraint or Make-Whole Payment is calculated for a Generator Unit, the un-normalised Market No-Load (MNLCuh) and Market Start-Up (MSUCuh) are used to calculate the amount of money that is paid for those cost elements.

This is a problem, because the SMP or ‘Energy’ algebra features loss-normalisation for Generator payments (recall the earlier example). Indeed in the above two equations, the energy components of these payments are loss-normalised (multiplication by MSQLFuh).

This means that, should the SEMC enforce as intended from the previous section, a situation would be created where Generators with TLAFs below 1.0 would be exposed to unintended gains when Constrained On, and unintended losses when Constrained Off due to the fact that the equations do not loss-normalise the payments made for out-of-market Start Up and No-Load. The converse situation arises for Generators with TLAFs above 1.0.

In addition, Make Whole Payments would be artificially inflated for Generators with TLAFs below 1.0 and suppressed for Generators with TLAFs above 1.0.

In the context of this, there is potential for perverse signals to be created in real-time, as a Generator may be able to materially benefit from being Constrained On (or Off).

4.2. Two Daily TLAFs

Generator Units submit a single set of Prices, Quantities, Start-Up and No-Load Costs that apply to the entire 30 hour optimisation period each trading day, however there are **two** different TLAFs applied to the half-hourly MSQ at Settlement; a ‘Day’ value and ‘Night’ value.

This means that Generators would face the subjective problem of how to precisely reflect the two TLAFs in their COD in the face of the intended Direction.

5. Decision

The SEMC has decided to Direct in accordance with the primary objective of this work, the philosophy of having a loss-adjusted merit order, and in the context of its decision relating to the economic short-run avoidability of transmission losses.

Regarding P/Q pairs, the only stumbling block in issuing a Direction for Prices to be divided by the best estimate of TLAF is the fact there are two daily TLAFs but only one set of P/Q pairs allowed per day. The SEMC feels that it is preferable to permit this problem to rest on the shoulders of Generators rather than instruct that TLAFs be treated otherwise (for example allow them to be ignored). The problem of coping with the two TLAFs has been worded in the Direction so as to place the responsibility with the Generator to calculate the 'best estimate' of the relevant TLAF that will apply to them for the Trading Day. The method a participant develops for this estimate would obviously come under the remit of the MMU to assess on a case-by-case basis should the need arise.

Regarding Start-Up and No-Load, the SEMC believes that the best solution is to Direct that these elements should be loss-adjusted and that the CONP and MWP algebra be modified so that payments for Start-Up and No-Load are loss-normalised. But this will require a T&SC and Central Systems change which will take time.

The question is then what to do in the interim period while these changes to the systems are being put in place. The SEMC considered two options:

1. Direct that the Start-Up and No-Load elements should be loss-adjusted starting immediately. Then no new Direction will need to be issued once the T&SC change is implemented.

2. Direct that the Start-Up and No-Load elements should **not** be loss-adjusted **until the T&SC change is implemented**.

The option of permitting participants to freely interpret this problem was struck off in the interest of promoting a transparent platform upon which the BCOP can be enforced fairly across the entire market both before and after a change to the market systems is implemented.

Option 1 would result in the potentially perverse incentives described earlier regarding Constrained On and Off behaviour, as well as exposing Consumers and System Operators to the difficult to quantify risk of an inflation to the total Dispatch Balancing Costs that will result.

Option 2 will ensure that Constraint and Make-Whole Payments are sound, in that Generators are only re-imbursed for their out-of-market costs and no more (or less), but will result in an inefficiency in the calculation of the Uplift values that are applied to each period.

Neither Option is particularly appealing, but **on balance the SEMC believes Option 2 to be superior**, because any short-fall any Generator makes resulting from a slightly sub-optimally calculated Uplift profile will be caught by the 'correct' Make-Whole algebra (correct only in the sense that no loss-normalisation is applied for items where no loss-adjustment was made at the bid).

As a final note, the MMU is not minded to pursue individual parties who have interpreted this problem to date one way or another, because the standing rules and arrangements are unclear. This General Direction is intended to shore up this uncertainty and provide the market with a clear policy and roadmap for fully addressing the issue.

6. SEM Committee GENERAL DIRECTION

D.1
In calculating the Price component of Price/Quantity pairs as part of daily Commercial Offer Data, a Generator must prudently incorporate the cost of transmission losses, with reference to the relevant Generator TLAFs. The bid must represent the Price at the Trading Boundary.

D.2
In calculating the Start-Up Cost and No-Load Cost as part of daily Commercial Offer Data, a Generator must **not** incorporate the cost of transmission losses, via TLAF or otherwise. The Start-Up Cost and No-Load Cost must be relevant at the Connection Point rather than the Trading Boundary.

D.3
In calculating the Quantity component of Price/Quantity pairs as part of daily Commercial Offer Data, a Generator must adhere to Grid Code Clause SDC 1.4.4.5 and **not** incorporate the cost of transmission losses, via TLAF or otherwise. The Quantity must be relevant at the Connection Point rather than the Trading Boundary.

D.4
As a corollary, the SEMC intends to propose and support a Trading and Settlement Code Modification as outlined in Annex 1 (the draft is an outline only). Upon implementation of this Modification (or any other Modification which accomplishes the intended effect), the SEMC intends to repeal D.2. above, to be replaced with the draft <D.5> below.

Additionally, the SEMC wishes to propose a clarifying amendment to Section SDC 1.4.4.5 of the Grid Code as drafted in Annex 2.

<D.5> **NOT A DIRECTION**
In calculating the Start-Up Cost and No-Load Cost as part of daily Commercial Offer Data, a Generator must prudently incorporate the cost of transmission losses, with reference to the Generator TLAFs. The bid must represent the Start-Up Cost and No-Load Cost at the Trading Boundary.

7. Annex 1 – Draft Modification to T&SC

4.136 For each Generator Unit u in each Trading Period h, the Market Operator shall calculate the Constraint Payments (CONPuh) as set out below, and the calculated value of CONPuh can be either positive or negative:

$$\cancel{CONPuh = TPD \times \begin{bmatrix} (DQLFuh \times DOPuh + DNLCuh + DQCCLFuh) \\ -(MSQLFuh \times MOPuh + MNLCuh + MSQCCLFuh) \end{bmatrix} + DSUCuh - MSUCuh}$$

$$CONPuh = TPD \times \begin{bmatrix} (DQLFuh \times DOPuh + DNLCLFuh + DQCCLFuh) \\ -(MSQLFuh \times MOPuh + MNLCLFuh + MSQCCLFuh) \end{bmatrix} + DSUCLFuh - MSUCLFuh$$

4.140 For The Market Operator shall procure that Make Whole Payments shall be calculated on a Billing Period basis for each Generator Unit u in Billing Period b, as follows:

$$\cancel{MWPub = Max\left\{\sum_{h in b}\left[\begin{pmatrix}(MOPuh - SMPh) \times MSQLFuh \\ + MNLCuh + MSQCCLFuh\end{pmatrix} \times TPD + MSUCuh\right], 0\right\}}$$

$$MWPuh = Max\left\{\sum_{h\ in\ b}\left[\begin{pmatrix}(MOPuh - SMPh) \times MSQLFuh \\ + MNLCLFuh + MSQCCLFuh\end{pmatrix} \times TPD + MSUCLFuh\right], 0\right\}$$

Where

1. MWPub is the Make Whole Payment for Generator Unit u in Billing Period b;
2. MOPuh is the Market Offer Price of Generator Unit u in Trading Period h;
3. SMPh is the System Marginal Price for Trading Period h;
4. MSQLFuh is the Loss-Adjusted Market Schedule Quantity for Generator Unit u in Trading Period h;
5. TPD is the Trading Period Duration;
6. MNLCLFuh is the Loss-Adjusted Market No Load Cost for Generator Unit u in Trading Period h;
7. MSQCCLFuh is the Loss-Adjusted Market Schedule Quantity Cost Correction for Generator Unit u in Trading Period h;

8. MSUCLFuh is the Loss-Adjusted Market Start Up Cost for Generator Unit u in Trading Period h;

9. the summation Σ is over all Trading Periods h in Billing Period b excluding any Trading Periods h in which the Generator Unit is Under Test.

8. Annex 2 – Draft Modification to Grid Code

SDC1.4.4.5 **Commercial Offer Data**

(a) Each:

- **Generator**;
- **Pumped Storage Generator**;
- **Interconnector User**;
- **Dispatchable Demand Customer**; and
- **Generator Aggregator,**

shall

<snip>

submit to the **TSO**, either directly or by means of an **Intermediary** on its behalf, **Commercial Offer Data** by **Gate Closure** for the following **Trading Day** in accordance with the **TSC.**

<snip>

~~All data items submitted under this SDC1.4.4.5 are to be at levels of **MW Output** at the **Connection Point**.~~

All MW Quantities submitted under this SDC1.4.4.5 are to be at levels of **MW Output** at the **Connection Point**.