Single Electricity Market

Treatment of Price Taking Generation in Tie Breaks in Dispatch in the Single Electricity Market and Associated Issues

Decision Paper

21 December 2011

SEM-11-105

Table of Contents

1 Introduction

1.1 Background

Following the publication by the Single Electricity Market Committee (SEMC) of a discussion paper on the potential challenges associated with increasing penetration of renewable generation, specifically wind, in the all-island system early in 2008, the SEMC proceeded to issue a consultation paper and proposed position paper on relevant matters in July 2009 and September 2010 respectively.[1]

The SEMC has now published a decision paper setting out its final decisions on issues addressed in the above papers. Two matters were not fully decided upon, namely, the treatment of priority dispatch, controllable price taking generation units in tie break situations in dispatch and the associated question of the method to be employed to reduce down MSQs of Price Takers in the Market Schedule under the Trading and Settlement Code (TSC) in Excess Generation Events (EGEs).[2] SEM-11-063, published on 26 August, consulted on relevant aspects of the above two issues.

These matters have now been decided upon by the SEMC and are outlined in the following paper.

1.2 Related Documents

This decision paper should be read in conjunction with the SEM publications outlined below.

- Wind Generation in the SEM: Policy for Large Scale, Intermittent, Non-Diverse Generation, Discussion Paper, 11 February 2008, SEM/08/002.
- Wind Generation in the SEM: Policy for Large Scale, Intermittent, Non-Diverse Generation, Initial Response to Comments and Next Steps. SEM-08-127, 28 September 2008, SEM-08-127.
- Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code, Consultation Paper, 8 July 2009, SEM-09-073.
- Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code, Proposed Position Paper and Request for Further Comment, 2 September 2010, SEM-10-060.
- Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code, Decision Paper, 26 August 2011, SEM-11-062.
- Treatment of Price Taking Generation in Tie Breaks in Dispatch in the Single Electricity Market and Associated Issues, Consultation paper, 26 August 2011, SEM-11-063.

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[1] Please refer to SEM-08-002, SEM-09-073 and SEM-10-060 at the following link here.
[2] Please refer to SEM-11-062 at the following link here.

- Treatment of Price Taking Generation in Tie-Breaks in Dispatch in the Single Electricity Market and Associated Issues, Clarification Note, 12 October 2011, SEM-11-086.

1.3 Structure of paper

This decision paper is structured in the following manner:

- **Section 1** provides an introduction and background to this issue;

- **Section 2** outlines the main themes of the submissions received to the consultation paper SEM-11-063;

- **Section 3** outlines the SEMC decision in relation to the two areas of consultation in SEM-11-063; and

- **Section 4** provides a summary of decisions made in this paper and the next steps of this workstream.

1.4 Queries to this decision

Queries on this paper should be submitted to Jamie Burke in the CER:

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2 Consultation Responses to SEM-11-063

2.1 Introduction

In SEM-11-063 the SEMC consulted on the treatment of tie breaks regarding controllable price taking priority dispatch generation units in dispatch, post application of the principles set out in section 4.4 of SEM-11-062. The paper also set out proposals regarding the related issue of the approach to the reduction of the Market Scheduled Quantities (MSQs) of price taking plants in Excess Generation Events (EGEs) under the Trading and Settlement Code (TSC) to meet system demand.

Subsequent to the publication of SEM-11-063 a number clarifications were requested by stakeholders. These queries were addressed by the Regulatory Authorities (RAs), with input provided by the Transmission System Operators (TSOs), in a clarification note (SEM-11-086), published on 12 October 2011.[3]

There were nineteen responses received to SEM-11-063. All non-confidential responses have been published on the AIP website alongside this paper. They were:

- Aeolus Windfarms Ltd.
- Barna Wind Energy Ltd.
- Beam Wind Ltd.
- Bord Gais Energy
- Bord na Mona Power Generation
- Coillte
- DW Consultancy Ltd.
- Energia
- ESB Wind Development
- Irish Wind Energy Association (IWEA)
- Killala Community Wind Farm
- Meitheal na Gaoithe
- North West Wind Ltd.
- Northern Ireland Renewables Industry Group
- NOW Ireland
- RES Group
- Scottish and Southern Energy (SSE)
- The Consumer Council
- Windsource Ltd.

Below is an outline of the responses to the two issues in the consultation and other general comments.

[3] Please refer to the following link here.

2.2 Tie Breaks in Dispatch

All of the responses commented on the issue of tie-breaks in dispatch, focused mostly on the treatment of Generators which are constrained, the composition of constraint categories, their characteristics and the implications for Generators outside of these groups.

Tie Break Constraints - Groups

SEM-11-063 proposed three possible constraint groups, the south west of Ireland, the north west of Ireland and the north west of Northern Ireland. SEM-11-063 and SEM-11-086 both noted that it was only practically possible to manage three constraint groups in total in real time dispatch, with modelling undertaken by the TSO reflecting, as closely as possible, the SEMC decision and followed through operationally. SEM-11-063 also proposed that the constraint groups would be reviewed periodically, but no more frequently than once per annum.

A few of the respondents believed that these constraint groups should relate to the 'bankability' of projects, not to specific defined areas which could change over time. A key concern for respondents was certainty. The argument put forward was that changes in the constraint groups would have a detrimental effect on the financing prospects of some Generators. These respondents proposed that the constraint groups should be fixed so as to reduce this uncertainty. Most of the respondents also questioned the treatment of Generators which would not fall into the three geographic areas identified by TSO modelling.

Tie Break Constraints - Categories

There were three constraint categories proposed in the consultation paper, strictly related to levels of firm access quantity (FAQ), with the firm access hierarchy approach only to apply to the constraint groups identified above. The constraint categories were (i) 66-100%, (ii) 33 – 66% and (iii) 0-33% firm. It was proposed in SEM-11-063 that for constraints, dispatching down of controllable wind generation units set out in these three categories would be carried out such that those falling into (iii) would be dispatched down before those falling into (ii), with those falling into (i) being dispatched down last. This proposal was supported by some respondents. It was noted in SEM-11-063 that it was not possible for a project connected behind a single connection point to be split between categories for dispatch such that the "firm" portion of the project (based on FAQ) was in one category with the "non-firm" portion in another.

A number of respondents noted the significant difference between the connection process in Northern Ireland and Republic of Ireland and the fact that SONI was intending to publish a consultation paper on the Northern Ireland Generator connection process (as highlighted in SEM-11-086).[4] These respondents believed that these factors contributed to them not being able to comment in the fullest sense to the SEM-11-063 proposal.

One respondent believed that units with 100% FAQ should not rest within any designated category. Similarly, units with 0% FAQ should be in a separate category given that this infers

[4] This SONI consultation has since been published and can be found here.

that the network has no capacity for this Generator. This respondent suggested categories of 0% FAQ, 1-49% FAQ, 50-99% FAQ and 100% FAQ.

Furthermore, as soon as reinforcement is made and where line upgrades are completed, this respondent believed that a Generator should automatically move up from whichever category it is included. Another respondent believed it is hard to judge whether the three categories proposed are appropriate or not, as the total installed capacity covered by each of the categories is not clear.

However, a number of respondents did propose an alternative approach to the definition of constraint categories, moving away from definition wholly determined by level of FAQ. These respondents proposed categories based on expected levels of constraints (in percentage terms), as opposed to FAQ levels.

Curtailment

With SEM-11-086 noting that it is not possible, in all cases, to unambiguously identify constraints from curtailment (particularly when there is a high level of interaction between the two), a number of respondents believed that it was not appropriate to implement a different approach to the dispatch of constraints and curtailment.

SEM-11-063 proposed that for price taking priority dispatch controllable wind generation units in tie-break situations, post application of the principles and hierarchy set out in section 4.4 of SEM-11-062, dispatching down to relieve curtailment issues would be done on a pro-rata basis on the island of Ireland. Essentially, this means that in order to relieve curtailment issues all connected price taking priority dispatch controllable wind generation units in tie-break situations, both firm and non-firm, would be dispatched down by an equal level (in % terms).

Responses on the issue fell into two camps, those that supported the SEMC proposal to pro-rata curtailment and those that supported adopting the same approach to curtailment as that for dealing with constraints, i.e. a firm access hierarchy approach or grand-fathering. This alternative approach would mean price taking priority dispatch controllable wind generation units in tie-break situations with higher levels of FAQ would get dispatched down in tie-break situations after those with lower levels of FAQ.

Those in favour of the SEMC proposal maintained that as curtailment is a system-wide issue (i.e. too much intermittent energy on the system) and very dependant on how the system is operated in real time, firm access and the conditions resulting in curtailment are unrelated. Basically constraints are a ‘local’ network issues that can be relieved by grid roll-out, while curtailment is an all-island issue. Therefore, all concerned Generators should be dispatched down in an equal fashion. One respondent qualified its support for the SEMC proposal as long as all wind Generators, regardless of firm status, were compensated for curtailment. A majority of responses also called for compensation for curtailment for all wind Generators irrespective of firmness.

A few respondents were against the pro-rata curtailment proposal. One argued that from an investment perspective, there was no available reasonably accurate projection of the levels of curtailment or its financial consequences for new Generators and without this; pro-rata treatment would be 'unbankable'. This respondent also believed that, from a consumer perspective it is clear that pro-rata curtailment would be more expensive as firm wind Generators that are curtailed would have access to the market schedule and would receive market price compensation. In contrast, non-firm wind Generators would only have access to the ex-post market schedule, to the extent that they are dispatched in real-time, and therefore would receive no market compensation when curtailed.

SEMC response

Tie Break Constraints – Groups

The SEMC acknowledge that significant analysis is needed to define the exact detail of the constraint groups, such as their geographic area. As noted in SEM-11-086 it is not until this analysis is completed by the TSOs can a definitive recommendation for each constraint group be provided. The three areas proposed in SEM-11-063, (the south west of Ireland, the north west of Ireland and the north west of Northern Ireland) were proposed at the time of consultation, because they represent the most significant constraints for wind generators on the island, at present.

The SEMC is aware that 'bankability' and stability are central to windfarm project development on the island and that 'fixing' such groups (i.e. the geographic area) would promote such stability. It is acknowledged that uncertainty may now be at a heightened level given the investment climate, financial market difficulties and planning issues. The SEMC believe that a function of the regulatory regime on the island is to provide stability where possible, in an effort to promote the bankability of renewable connections and facilitate their participation of in the market.[5] This step will help deliver the 2020 RES-E targets in Ireland and Northern Ireland.

On review of the responses received to SEM-11-063 the SEMC acknowledge that changing constraints groups 'no more frequently than once per annum' (as proposed in SEM-11-063) will lead to uncertainty. Therefore, the SEMC has decided to fix the maximum size of the constraint groups (geographic size/electrical boundary, i.e. nodes) in Year 1, with the groups only getting smaller in subsequent years as the network is built out. This is outlined in greater detail in the next section of the paper.

From a dispatch perspective the tie-break approach proposed in SEM-11-063 works well when there is little or no interaction between constraint groups. This is largely the current case with the proposed three constraint groups. However, this does not imply that network constraints do not exist elsewhere in the network on the island. When a constraint arises outside of the stated constraint groups, or when there is significant interaction between constraint groups, then the TSOs will endeavour to resolve the issue by dispatching down the units that best affect the security issue at hand.

The TSOs have stated that to ensure system security this real-time dispatch process will ignore any constraint group definition, with all the uncertainty that accompanies this. Finally,

[5] Please refer to the SEM Memorandum of Understanding at the following link here.

it is worth noting that constraint groups will only be binding for a specific set of contingencies, relatively local to the area in question.

Tie Break Constraints – Categories

As stated in SEM-11-063 the SEMC notes that connection processes and associated issuance of FAQ centre around the ability of the network to take the Maximum Export Capacity (MEC) of a Generator under normal, defined conditions and hence relate to constraints. Curtailment is associated with the operation of variable (wind) generation and with cases where there is too much generation relative to demand. Constraints, it can be said are network specific, curtailment is an all-island issue (system wide issue). SEM-11-063 also stated that in putting in place principles regarding tie-breaks in dispatch, due regard should be given to the above, i.e. connection processes and associated issuance of FAQ.

Although there is difference currently between the connection process in Northern Ireland and Republic of Ireland, SONI has published a consultation paper on the Northern Ireland Generator connection process.[6] That consultation paper proposes to align the processes in both jurisdictions with regard to allocation of FAQ.

In relation to the specific proposal which was put forward by some respondents to base the constraints categories on modelled levels of constraints by percentage, instead of basing the categories on FAQ, the SEMC acknowledges that this approach offers some advantages for some Generators. The main reason put forward by respondents for this approach would be that it would provide certainty to groups of Generators regarding their expected level of constraints. Those generators in the lower constraints category (e.g. 3 – 5%) would be turned down by the TSO after those Generators in the higher constraints category (5% +). However, the SEMC does not think it appropriate to allocate a hierarchy in tie-break dispatch decisions based on levels of potential constraints faced by a Generator, which can be reflected in the bankability of the project. Such an approach would in effect involve favouring certain Generators over others on the basis of modelled levels of constraints, the accuracy of which depends on a wide range of variable factors.

In addition this approach may lead to an accusation that the SEMC is favouring more "financially viable" projects in tie-break decisions over other less "financially viable" projects, where those projects with a higher figure for modelled constraints would be seen as less financially viable. This impact would then be further reinforced by dispatching to ensure that those generators in the higher constraints category are turned down first. The SEMC does not believe this to be suitable. Basing categories on FAQ is directly linked to roll-out of network infrastructure, which in itself is directly linked to actual levels of constraints. The final categories are outlined in the next section of the paper.

Curtailment

The SEMC acknowledges that it is not possible for the TSOs to unambiguously identify constraints from curtailment at all times in dispatch. Real-time dispatch requires very quick

[6] Please refer to footnote 4 above.

decision making on the part of the TSOs with an (increasing) number of variables and principles to consider, with system security being paramount.

The treatment of curtailment is a difficult one for the SEMC. Essentially, the decision involves deciding on whether to pro-rata curtailment (where all Generators are dispatched down by the same percentage level) or adopt the same approach for dealing with constraints, i.e. a firm access hierarchy approach or ‘grand-fathering’. As noted above, curtailment is associated with the operation of variable (wind) generation and with cases where there is too much generation relative to demand (i.e. too much intermittent generation on the system). The SEMC acknowledges that under the pro-rata approach, curtailment is effectively uncapped (depending on the level of connected wind generation). Yes pro-rata treatment would see all Generators in tie-break situations treated equally, as the level of renewable generation on the system in real time increases, but in the current investment climate this might have the adverse impact of making short to medium investment decisions unbankable, as their exposure to curtailment could be significant.

The SEMC believe that a function of the regulatory regime on the island is to provide predictability, in an effort to promote the bankability of renewable connections, and in doing so help deliver the 2020 RES-E targets in Ireland and Northern Ireland. The SEMC believe that a firm access hierarchy approach/grand-fathering approach to curtailment in tie-break situations will help promote that predictability for projects due to build over the short to medium term, which will in turn contribute to meeting the 2020 targets in an efficient manner. This decision is outlined further in the next section of the paper.

2.3 Quantity of Price Taking Generation Charged PFloor in an EGE

As noted in SEM-11-063 given the tie-break proposals, and the SEMC views regarding the degree of divergence between the Market Schedule and dispatch in the SEM as set out in SEM-11-062, it was considered appropriate to reflect these proposals in the quantity of price taking generators that is charged PFloor in an EGE.

This would also ensure that parties that are not dispatched in these situations would not be charged under the TSC. Basically this means that only Generators who are being dispatched will have to pay PFloor in an EGE, i.e. not all wind in the market schedule, only those dispatched, will have to pay PFloor. A number of respondents supported this proposal.

A few respondents asked for further clarity on this matter, with one questioning whether this would mean firm access Generators effectively being penalised by a negative PFloor. Another respondent queried at what point in time would the TSOs determine that there is likely to be an EGE, how is the output of wind defined against the synchronous generation and does this vary by region.

SEMC response

The SEMC continues to believe that only dispatched Generators should pay PFloor in an EGE under the TSC. This is the fairest approach to this issue. Although presently rare, an EGE will occur when there is an excess of price taking generation over System Demand, and therefore it is appropriate that those Generators who are contributing to this excess should be charged the PFloor. Generators which are not contributing to this EGE by virtue of not being dispatched at that time should not be charged.

In relation to the queries from respondents, as noted the excess generation event is a Trading and Settlement concept related to pricing in the SEM. As such there is no direct operational equivalent. However there is an operational policy which limits the aggregated output of all non-synchronous generation on the Ireland and Northern Ireland power system to less than 50%. This policy is based on detailed system analysis performed in the TSOs facilitation of renewables studies.[7]

The location of the windfarms has no impact on the implementation of this policy. It should be noted that this operational policy is likely to have increasing impact on the curtailment levels of windfarms in the future, which the TSOs and RAs through the *DS3* programme are seeking to address.[8]

2.4 General comments

Hierarchy

The majority of respondents questioned the principles and hierarchy set out in section 4.4 of SEM-11-062. One respondent stated that the proposed list was materially different than what was included in the previous consultation in that the hierarchy will favour interconnection access to the system over price-taking generation, such as windfarms. Another respondent called for considerable attention to be given to this issue of hierarchy to ensure wind energy on the system is maximised, bearing in mind restrictions on trading across interconnectors.

Some respondents questioned the decision in SEM-11-062 where constrained conventional plant will not be de-committed, but rather constrained down to a minimum stable generation. One considered this position to be flawed, 'with the potential to combine poor generating efficiencies of thermal plant with an unnecessary curtailment of renewable generation'.

Temporary Connections

A temporary connection is defined as a connection to the electricity network which is completed in advance of the permanent shallow connection for a Generator.

SEM-11-063 proposed that those Generators with temporary connections will fall into 0-33% constraint category, i.e. will be dispatched down first in a tie-break situation. A number of respondents were concerned with this proposed treatment of temporary connections. Some believed that where FAQ is available, it should be allocated to the temporary connections so that these temporary connections can use the FAQ, with projects assessed on the level of firmness at their connection node and not whether the connection is temporary or permanent.

[7] Please refer to the following link on EirGrid's website here.
[8] Please refer to the following link on EirGrid's website here.

At the same time, one respondent believed that the proposals in SEM-11-063 did not go far enough to protect non-firm permanent Generators from potentially higher constraints caused by temporary connections. This respondent noted that the CER decision paper on Connection Offer Policy and Process (CER/11/093)[9] stated that pre-Gate 3 Generators should be protected as much as possible from enduring higher constraints than would otherwise have been the case had temporary connections not been permitted.

Sub 10MW Generation

It is acknowledged that projects currently in the 5-9.9MWs MEC must be controllable, but can choose whether to trade through the market pool or not. A number of respondents noted that SEM-11-063 does not distinguish between different levels of controllable wind farms and proposes to treat all controllable wind farms equally. As a result these respondents believed that the 5–9.9MWs windfarms will be discriminated against, unless they also receive compensation in accordance with their level of firm grid access. They asked that market mechanisms be put in place so that these Generators, which are outside of the market, are eligible for compensation

SEMC response

Hierarchy

The SEMC acknowledges that there has been a considerable level of response on the hierarchy outlined in SEM-11-062. However, the issues for consultation in SEM-11-063 do not concern the hierarchy identified in SEM-11-062 or de-commitment of conventional generation and will therefore be not addressed in this decision paper. Interested parties are asked to submit to the SEMC directly if they wish to raise these matters further; however the SEMC does not intend to re-open a decision which has only recently been made after a lengthy period of uncertainty.

It should be noted that in SEM-11-062 the SEM Committee decided to adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations and where this can be done in a manner that does not threaten the delivery of renewables targets. The SEMC continues to believe that the hierarchy outlined in section 4.4 of SEM-11-062 meets those principles.

Temporary Connections

The SEMC acknowledges that CER/11/093 states that pre-Gate 3 Generators in a ROI context should be protected as much as possible from enduring higher constraints than would otherwise have been the case had temporary connections not been permitted, however the matters for discussion in this paper are of an all-island nature.

Nonetheless, the SEMC believes that the principle outlined in CER/11/093 with regard to temporary connections, where those with temporary connections should be constrained such that other Generators on the local network are not impacted negatively (e.g. suffering local

[9] Please refer to the following link here.

constraints due to the temporary connection) is correct. The fundamental purpose of allowing temporary connections from a system perspective is to connect generation to the system sooner than would otherwise be the case, thus aiding achievement of the 2020 RES-E targets. Temporary connections are not designed as a mechanism for a Generator to become "firm" or gain rights associated with firmness sooner than would otherwise be the case. It is not there so that grid connection rules can be altered to be detriment of others, such as non-firm permanent connections. This matter is outlined in further detail in the next section of the paper.

Sub 10MW Generation

The SEMC does not believe market rules need to be altered to fix apparent 'discriminatory' practice against Generators in the 5-9.9 MWs MEC category, which are outside of the market. These Generators can choose whether to trade through the market pool or not. Commercial decisions of whether to enter into out-of-market support mechanisms are also not the concern of the SEMC.

Finally, projects in the 5-9.9MW being controllable is a grid code matter and is not the concern of market arrangements in tie-break situations. Therefore, the SEMC will adopt the principle in the consultation paper which does not distinguish between different levels of controllable windfarms - all controllable windfarms will be treated equally.

3 SEMC Decision

3.1 Introduction

The SEMC recognises that this is a key matter for industry falling out of the recent decision on *Principles of Dispatch and the Design of the Market Schedule* (SEM-11-062). There is a central question to this issue - as to what basis do the TSOs make the decision for dispatching plant down when the plant available is seen as equal by the TSOs, i.e. no deciding indicator, including a bid price differential, exists to support such a decision.

The RAs have discussed feasibility issues regarding implementing approaches to tie-breaks for price taking generators in dispatch with the TSOs and confirmed that the decisions outlined below can be implemented. The decisions outlined in this paper refer to constraint and curtailment in tie-break situations only.

3.2 Dispatch Principles

Those units afforded mandatory priority dispatch in legislation must be given priority over those afforded discretionary priority dispatch in legislation. The hierarchy set out in section 4.4 of SEM-11-062 will be employed by the TSOs in the dispatch decision making processes.

The approach set out in the bullet points that follow will be implemented post application of the principles set out in section 4.4 of the SEM Committee's decision paper on dispatch and scheduling (SEM-11-062).

- For non wind price taking priority dispatch generation units, where a choice must be made within a given group in the hierarchy set out in section 4.4 of SEM-11-062 then dispatching down will be done on a pro-rata basis for both constraining and curtailment within the relevant group (e.g. peat represents one group, with High Efficiency CHP/biomass/hydro representing another group, etc).[10]

- For price taking wind generation, the order set out in section 4.4 of SEM-11-062 will apply such that:

    - wind generation units which should be controllable but which do not provide this service will be dispatched down first;

    - wind generation units which are controllable will be dispatched down next in accordance with the principles set out in section 3.4 of this paper; and

    - wind generation units that are derogated from relevant Grid Code requirements or which are not required to be controllable under those requirements will then be dispatched down where possible. This will include wind generation units that are commissioning for the appropriate duration as agreed with EirGrid. This includes

[10] Note that, as stated in section 4.4 of SEM-11-062 for non-wind price taking generation units dispatching down to minimum load is to be carried out, before moving to the next group in the hierarchy.

wind generators that are, at the time of publication of this decision paper, engaging with the relevant TSO in the context of a defined process to move to being controllable and thus compliant with Grid Code requirements. If such Generators fail to meet agreements with the relevant TSO under the defined process in the agreed timelines then they will move up the order and be dispatched down first amongst the wind group.

It should be noted that in all constraint situations outside of a tie-break scenario the TSOs will dispatch down wind generation units in a manner that best relieves the constraint, whilst minimising the dispatching down of wind generation.

3.3 Tie Break Constraints - Groups

On advice from the TSOs a maximum of three constraint groups will be modelled on the island with two in Ireland and one in Northern Ireland (if required) that represent the most significant constraints for wind Generators at present. These groups – boundaries to be advised/ developed by the TSOs are likely to be the south west of Ireland, the north west of Ireland and the north west of Northern Ireland - will form the 'constraints list' and will be published in the coming months. Categories in each constraint group will be used to then determine an order for dispatching down where required to address constraints and this is described in section 3.4.

As noted in section two above the SEMC are aware that 'bankability' and stability are central to windfarm project development on the island and that 'fixing' such groups (i.e. the geographic area) would promote such stability. It is acknowledged that uncertainty may now be at a heightened level given the investment climate, financial market difficulties and planning issues. The SEMC believes that a function of the regulatory regime on the island is to provide stability, in an effort to promote the bankability of renewable connections, and in doing so help deliver the 2020 RES-E targets in Ireland and Northern Ireland.

On review of the responses received to SEM-11-063 the SEMC acknowledge that changing the basis of constraints groups 'no more frequently than once per annum' (as proposed) will lead to uncertainty. Therefore, the SEMC has decided to fix the maximum size of the constraint groups (i.e. fixed by geographic size/electrical boundary – nodes) in Year 1.[11] Over time, the impact of being in a constraint group will diminish as the network is upgraded to meet that constraint. In other words, as the network is build, Generators will be able to 'drop-out' of the constraint group. It will be up to the TSOs to determine if and when any particular Generator drops out of the constraint group (dependent upon network build).

Therefore, only Generators within the boundary of the group will be included in that group and as the geographic size of the group gets smaller, certain Generators will fall out of the group. Eventually the transmission network will be developed to a level where constraints have been minimised and the group will essentially disappear.

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[11] Year 1 commences once the TSOs have completed all of the constraint group modelling and ultimate approval from the RAs on the advised groups.

It should be noted that a maximum of three constraint groups will be modelled and a constraint group ‘disappearing’ does not imply that another constraint group will be developed to replace it. Constraint groups will not be developed just to maintain the same original number of them.

In an effort to promote stability and certainty the TSOs will be asked to develop no more than three constraint groups of a size ‘conservative’ in nature (i.e. large), with flexibility provided at the borders of them. These groups will cover the nodes that are included in the lists, as this promotes greater transparency. The SEMC acknowledges that the lists will change as deep reinforcements are completed and more projects connect to particular nodes, but the maximum size of the constraint group boundaries will be established in Year 1 and will only reduce in subsequent years. Constraint groups will not get bigger, in terms of their geographic size, from that established in Year 1.

As noted above for constraints not included in the Year 1 fixed constraints list or outside of a tie-break situation the TSOs will dispatch down wind generation units in a manner that best relieves the constraint, whilst minimising the dispatching down of wind generation. Constraint groups will only be binding for a specific set of contingencies, relatively local to the area in question and due to a tie-break situation.

Finally, the TSOs are now tasked with identifying the maximum 3 constraint groups on the island and submitting the groups to the RAs by end Q1 2012 for approval and publication.

3.4 Tie Break Constraint – Categories

It was noted in section two that the SEMC acknowledges some potential advantages of basing the proposed categories, which the TSOs will follow when dispatching down, on expected or modelled levels of constraints (in percentage terms), as opposed to FAQ. The primary advantage would be that it would provide certainty to Generators in the “better categories” (e.g. 3 – 5% constraints category) regarding the level of constraints which they would incur. However, the SEMC does not think it appropriate to allocate a hierarchy in tie-break dispatch decisions based on levels of potential constraints faced by a Generator, which can be reflected in the bankability of the project.

Constraints are network-specific and can be directly attributable to the ability of the network to take the MEC of a Generator. However implementation of this option would involve basing dispatch decisions on modelled levels of constraints as well as an arbitrary application of a category threshold (e.g. a 3 – 5% constraints category). This approach would also likely lead to an actual dispatch which is more inefficient than if the dispatch was to broadly follow available network as provided for through FAQ. Basing tie-break decisions on expected levels of constraints may lead to an accusation that the SEMC is favouring more ‘financially viable’ projects in tie-break decisions over other less financially viable projects.

Indeed the very application of categories based on modelled levels of constraints would automatically lead to the creation of ‘favoured’ projects, which would be seen as financially viable and ‘unfavoured’ projects. Furthermore, viable projects with a modelled level of constraints just beyond the threshold level would be unfairly disadvantaged compared to similar projects with a slightly less level of modelled constraints. Such an approach would in effect involve favouring certain Generators over others on the basis of modelled levels of constraints, the accuracy of which depends on a wide range of variable factors.

The SEMC does not believe this type of solution to be suitable. A number of the respondents suggested modifications to the proposed constraints groups (based on firm-levels) and the SEMC has taken these suggestions into account. Therefore a modified version of the constraint categories outlined in SEM-11-063 will be adopted.

For price taking priority dispatch controllable wind generation units in tie break situations post application of the principles and hierarchy set out in section 4.4 of SEM-11-062, the following will apply:

I. those controllable wind generation units with a FAQ of 100% (i.e. 'fully-firm') of their MEC;

II. those controllable wind generation units with a FAQ of between 0.1% and 99.9% (inclusive) of their MEC (i.e. partially firm); and

III. those controllable wind generation units with a FAQ of 0% of their MEC (i.e. 'non-firm'). As per the proposal in SEM-11-063 those with temporary connections or those that have not been allocated FAQs will fall into this category for their entire installed capacity up to the MEC that they have applied for in a completed application for connection to the relevant body.

The three categories of units will be used namely such that for constraints, dispatching down of controllable wind generation units set out above will be carried out such that those falling into (iii) will be dispatched down before those falling into (ii) with those falling into (i) being dispatched down last.

It is important to note that within (ii) and within (iii), Gate 3 non-firm will be turned down before pre Gate 3 non-firm in Ireland. For Northern Ireland no similar categories will apply in (ii) and (iii) at present. If categories are subsequently required, these will be proposed to the SEMC by SONI.

Within each category, the TSOs will dispatch down all Generators in that constraint category on a pro-rata basis. As per SEM-11-063, where there are both constraints and curtailment issues arising, the TSOs shall first dispatch to manage the constraint issues and then work to address the curtailment issues.

3.5 Curtailment

The SEMC is of the view that in principle, efficient market outcomes based on the competitive interaction of market participants is most appropriate and should always be pursued where possible. However, the SEM Committee, following due consideration of responses received on this issue, is of the view that there is merit in this particular instance in taking an approach that provides for consistency in decision making that will better facilitate the continued operation and delivery of renewable plant who have or are in the process of securing finance.

The SEMC believes that a grand-fathering approach to curtailment issues (post application of the principles and hierarchy set out in section 4.4 of SEM-11-062), akin to the treatment of constraints as outlined in section 3.4 above, will help the bankability of those Generators with firm connection offers or who are earlier in the 'connection queue'. The SEMC can see the argument that such an approach should enhance investor confidence and help delivery of renewable projects and, by extension, progress on achieving the 2020 renewable obligations, at least in the short to medium term.

From an economic theory perspective, grand-fathering of curtailment should provide a signal to the marginal renewable plant in future years of whether it is financially viable to connect to the system. With the level of renewable generation looking for connection to the system far exceeding that required to meet the 2020 RES-E targets grand-fathering of curtailment may provide an efficient entry signal for those in the connection queue.

Furthermore, as noted in section two, from an all-island customer perspective it is acknowledged that pro-rata curtailment is likely to be more expensive as firm wind generators that are curtailed will have access to the market schedule and will receive market price compensation. In contrast, if a firm access hierarchy approach is adopted where non-firm wind generators are dispatched in real time, no market compensation will be paid out when these Generators are curtailed. A grand-fathering approach will result in savings to Dispatch Balancing Costs (DBC) for the all-island customer. It is acknowledged that due to the calculation of Scheduled Demand in each trading period contained in the Trading and Settlement Code[12], this benefit may be somewhat off-set or balanced by possible slight increases in the the level of SMP due to a grand-fathering approach.

The SEMC believes that, on a net basis a grand-fathering/firm access hierarchy approach as identified in section 3.4 above to curtailment in tie-break situations is the most efficient and cost effective for the all-island customer, bearing in mind the delivery of the 2020 renewable targets.

The attainment of 2020 RES-E targets in Ireland and Northern Ireland is of significant importance to SEMC. Inevitably, however, this will be at the expense of other 'later' developers. Therefore, in the interests of fairness for projects which are expected to connect in the medium to long term, the firm access hierarchy approach to curtailment may be reviewed again by the SEMC once the 2020 targets have been reached, i.e. 40% of electricity consumption from renewable sources in both Ireland and Northern Ireland.

The SEM Committee has taken this decision to provide as much certainty as possible to Generators who are closer to connection and more likely to contribute to meeting Ireland and Northern Ireland's renewable targets. While the SEMC accepts non-firm Generators will have to accept greater levels of curtailment in the short to medium term than they would have under a pro-rata approach, the approach is designed to Generators who have made investments, particularly those in the most efficient locations. This approach is consistent with grand-fathering of access rights in the SEM, as favoured by the SEM Committee.

[12] Trading and Settlement Code Appendix N – paragraph 32.

For controllable wind generators within a particular constraint category who have already been constrained down (due to a network constraint), the curtailment should only apply to their availability after being constrained, i.e. the level of controllable MWs left after the constraint has been dealt with. Therefore post application of the principles and hierarchy set out in section 4.4 of SEM-11-062, where both constraint and curtailment occurs, the TSOs should first deal with the constraint and then deal with the curtailment on an all-island basis.

Take for example a situation where after constraints have been relieved wind availability in EirGrid is 1000MW of controllable generation (a mixture of non-firm/partial firm and fully firm) and SONI is 250MW controllable generation (also a mixture of non-firm/partial firm and fully firm) - 500MW is to be dispatched down. EirGrid will dispatch (500)*(1000/1250) = 400MW and will do this by curtailing down all controllable non-firm generation first before moving onto partially firm, before finally moving on to fully firm. Similarly, SONI will dispatch down 100MW by curtailing down all controllable non-firm generation first, before moving onto partially firm, before finally moving on to fully firm. Dispatch will be on pro-rata of availability of the units within each category of firmness (post constraint). So in the above example if 600MWs of the available controllable generation in EirGrid was non-firm all units in this category would be curtailed down by 66%.

The burden sharing process for curtailment between Ireland and Northern Ireland will be based on the ratio of wind availability in each jurisdiction. In the above example the ratio of wind availability in ROI compared to NI is 4:1 (i.e. 1000MWs to 250MWs) and curtailment has taken place based on this relative amount (i.e. 400 MWs to 100MWs). As curtailment is a system wide issue, the burden of resolving curtailment is to be shared across both jurisdictions on the island.

The SEMC are aware that treating curtailment in this manner will involve changes to the EMS wind dispatch tool and the TSOs are now tasked with identifying those EMS/IT changes by end Q1 2012. This arises due to the increased complexity introduced in curtailment, which is now to utilise a mix of firm/ non-firm access, gate order and a pro-rata minimise dispatch down of wind approach as required. Therefore, the SEMC has decided to implement this decision in curtailment in principle subject to the costings of changes to the EMS wind dispatch tool, which are not expected to be significant. In addition, the RAs are aware that the TSOs had intended to examine adaptations and improvements to the functionality of the EMS wind dispatch tool as part of the DS3 review.

This TSO submission by end Q1 will be discussed separately between the RAs and TSOs and may be included as part of the DS3 programme, within which the TSOs are examining control centre tools in a broader context of minimising curtailment whilst maintaining system security and reliability.

Over the coming months, if curtailment situations arise, the TSOs will continue to implement the present pro-rata approach to curtailment, as manual workarounds for grand-fathering of curtailment are not practical without IT changes in place.

3.6 PFloor in an EGE and Temporary Connections

The proposal contained in SEM-11-063 will be adopted. The SEMC considers that it is appropriate to reflect the proposals regarding dispatch of price taking generation in the approach to the detailed implementation of this decision regarding the quantity of price taking generators that is charged PFloor in an EGE. This will also ensure that Generators that are not dispatched in these situations are not charged under the TSC. Only dispatched Generators will pay PFloor in an EGE under the TSC. This is seen as the fairest approach to this issue.

With regard to temporary connections, they will be contained in the 0% FAQ constraint category outlined in section 3.4 above.

4 Summary and next steps

4.1 Summary

After consideration and post review of the responses received to SEM-11-063, the SEMC has made the following decisions in respect of the treatment of price taking generation in dispatch tie breaks in the SEM.

- Dispatch Principles will be as the principles set out in section 4.4 of the SEM Committee's decision paper on dispatch and scheduling (SEM-11-062).

- In all constraint situations outside of a tie-break scenario the TSOs will dispatch down wind generation units in a manner that best relieves the constraint, whilst minimising the dispatching down of wind generation.

- Tie Break Constraints – groups. A maximum of three constraint groups will be modelled on the island and the maximum size of these will be fixed in terms of their geographic size/electrical boundary, i.e. nodes in Year 1. As the network is built out the groups will get geographically smaller, which will subsequently lead to Generators 'falling out' of the constraint groups. When the level of transmission network is sufficient to allow for the minimisation of constraints in a particular group that group will effectively disappear.

- Tie Break Constraints – categories. A modified version of the constraint categories outlined in SEM-11-063 will be adopted. This continues with the 'grand-fathering' approach to constraints based on levels of firmness. These categories will be as follows:

  (i) those controllable wind generation units with a FAQ of 100% (i.e. 'fully-firm') of their MEC;

  (ii) those controllable wind generation units with a FAQ of between 0.1% and 99.9% (inclusive) of their MEC (i.e. partially firm); and

  (iii) those controllable wind generation units with a FAQ of 0% of their MEC (i.e. 'non-firm'). As per the proposal in SEM-11-063 those with temporary connections or those that have not been allocated FAQs will fall into this category for their entire installed capacity up to the MEC that they have applied for in a completed application for connection to the relevant body.

  The three categories of units will be used namely such that for constraints, dispatching down of controllable wind generation units set out above will be carried out such that those falling into (iii) will be dispatched down before those falling into (ii) with those falling into (i) being dispatched down last.

  It is important to note that within (ii) and within (iii), Gate 3 non-firm will be turned down before Gate 2 / other non-firm in Ireland. For Northern Ireland no similar categories will apply in (ii) and (iii) at present. If categories are subsequently required, these will be proposed to the SEMC by SONI.

- Curtailment – the approach proposed in SEM-11-063 (i.e. pro-rata) will not be adopted. Curtailment will now be carried out on the same basis as constraints as identified in section 3.4 of this paper – grand-fathering. This decision is made in principle, subjects to the costing of changes that will need to be made to the EMS Wind Dispatch Tool. Over the coming months, if curtailment situations arise, the TSOs will continue to implement the present pro-rata approach to curtailment.

- PFloor in an EGE - Generators that are not dispatched in the EGE event will not be charged under the TSC. Only dispatched Generators will pay PFloor in an EGE under the TSC.

- Temporary connections and sub 10 MW Generation – temporary connections will be placed in the 0% FAQ constraint category and all controllable windfarms will be treated equally irrespective of level of MEC.

4.2 Next Steps

The TSOs will now undertake modelling to identify the specific areas/boundaries of the constraint groups proposed in the south west of Ireland, the north west of Ireland and the north west of Northern Ireland (if required) and submit to the RAs by end Q1 2012 at the latest. These groups will then subsequently be approved and published by the RAs. The TSOs will also work to identify the required IT changes needed to implement the above decisions, especially with regard to treatment of curtailment. The costings of these IT changes will also be submitted by the TSOs by end Q1 2012 at the latest.

Queries on this decision paper should be submitted to Jamie Burke (jburke@cer.ie) in the CER.