SEM committee

Integrated Single Electricity Market

(I-SEM)

Balancing Market Principles Code of Practice

Decision Paper

SEM-17-048

11th July 2017

TABLE OF CONTENTS

ACRONYMS

BCoP: Bidding Code of Practice

BM: Balancing Market

BMPCoP: Balancing Market Principles Code of Practice

BNE: Best New Entrant

CER: Commission for Energy Regulation

COD: Commercial Offer Data

CPM: Capacity Payment Mechanism

CRM: Capacity Remuneration Mechanism

DAM: Day Ahead Market

DBCs: Dispatch Balancing Costs

DS3: Delivering a Secure Sustainable Electricity System

EBNC: Electricity Balancing Network Code

EOH: Equivalent Operating Hours

ETA: Energy Trading Arrangements

ETS: Emissions Trading Scheme

FCO: Forward Contracting Obligation

FTC: Fuel Transportation Cost

GPI: Generator Performance Incentive

GTC: Gas Transportation Capacity

IBP: Irish Balancing Point

IDM: Intra Day Market

IPP: Imbalance Pricing Period

I-SEM: Integrated Single Electricity Market

ISP: Imbalance Settlement Period

NBP: National Balancing Point

NI: Northern Ireland

NIV: Net Imbalance Volume

MWh: Mega Watt hour

PN: Physical Notification

PQ: Price Quantity

RAs: Regulatory Authorities

RO: Reliability Option

SEM: Single Electricity Market

SRMC: Short Run Marginal Cost

T&SC: Trading & Settlement Code

TSO: Transmission System Operator

UK: United Kingdom

VOM: Variable Operating and Maintenance

1 EXECUTIVE SUMMARY

1.1.1 Following the publication of the “Balancing Market Principles Code of Practice Consultation Paper” (SEM-17-026), the “Consultation Paper”, and consideration of responses received, the SEM Committee has prepared this “Balancing Market Principles Code of Practice Decision Paper” (SEM-17-048), the “Decision Paper”.

1.1.2 The primary objective of the Consultation Paper was to provide stakeholders with an opportunity to identify areas within the draft Balancing Market Principles Code of Practice (BMPCoP) document (SEM-17-026a), the “Draft BMPCoP”, which may require further clarity. Additionally, respondents were requested to:

- identify any other related issues that should be considered by the SEM Committee prior to finalising the Draft BMPCoP; and
- consider whether the Draft BMPCoP accurately reflects policy decisions taken in the “Complex Bid Offer Controls in the I-SEM Balancing Market” decision paper (SEM-17-020).

1.1.3 Subsequent to the closure of the consultation window (i.e. 12th May 2017), the SEM Committee received thirteen responses to the Consultation Paper. In general, responses provided both proposed amendments to the Draft BMPCoP and requested further clarity from the SEM Committee.

1.1.4 Such respondents’ comments included adding a statement of aims within the Draft BMPCoP, changing the wording within the Draft BMPCoP to ensure Gas Transportation Capacity (GTC) costs are not double counted and providing a clarification statement on eligible costs relating to the transportation of domestic gas and other fuels.

1.1.5 Additionally, respondents’ requested clarity on issues such as the recovery of eligible cost of start-up fuels in the case of plants that use different fuels for start-up and incremental operation, the relevant time period within which Opportunity Cost is determined and what generating plants will be subject to the finalised BMPCoP.

1.1.6 With reference to respondents’ comments regarding clarity with the Draft BMPCoP, this Decision Paper has determined that many of the specific textual clarifications suggested by respondents are appropriate and will be incorporated in the BMPCoP. However, there are certain comments that the SEM Committee does not agree with, and the SEM Committee has provided its rationale accordingly.

1.1.7 Some respondents also objected to the SEM Committee’s previous policy decisions regarding bid offer controls.

1.1.8 Such comments pertained, inter-alia to the transfer of content from generator/supplier licence conditions to the Draft BMPCoP, changes to the definition of Short Run Marginal Cost (SRMC), level of prescription within the Draft BMPCoP, the change management provisions for the BMPCoP and the treatment of risk and long term GTC costs as a non-eligible SRMC items.

1.1.9 As a matter of course, the SEM Committee does not typically respond to objections or claims on matters on which a consultation has been conducted, including "Offers in the I-SEM Balancing Market" (SEM-16-059) and where a decision has been made (i.e. SEM-17-020).

1.1.10 However, due to the extent that these comments regarding previous policy decisions are raised by a variety of respondents and given the importance of having in place a robust and accepted market power mitigation strategy, the SEM Committee deems it appropriate to respond to the main comments received in order to reiterate its position on such matters and, where appropriate, provide further clarity on policy decisions taken within SEM-17-020 and how they are implemented in the BMPCoP.

1.1.11 Regarding previous policy decisions, the SEM Committee re-affirms its decision to only allow gas generating units to recover SRMC gas transportation costs that vary with output, and its decision to amend the definition of SRMC (while also transferring the definition of SRMC from the generator/supplier licence to the BMPCoP document). Additionally, the SEM Committee rejects claims that the proposed BMPCoP is unduly prescriptive and has moved away from a principles-based approach.

1.1.12 The SEM Committee considers claims that generation owners will be deprived of an opportunity to recover their full costs as a result of market power mitigation are not accurate, and refers respondents to its response to such claims in SEM-17-020 including Section 3.5.

1.1.13 With reference to respondents' concerns regarding future changes to the BMPCoP, the SEM Committee has added detailed change management provisions to the BMPCoP (see Section VI of the revised BMPCoP – SEM-17-049).

1.1.14 The SEM Committee is not revising its policy decision within SEM-17-020 regarding risk, such that generator units will not be able to incorporate risk within its three part bids and offers as a standard Eligible Cost Item. However, the SEM Committee does recognise that some individual generator units may face a residual risk that may not be mitigated by regular maintenance and insurance. Consequently, there may be a basis for including residual risk in a generation unit's start-up costs.

1.1.15 The SEM Committee has determined that a licensee may apply to the Regulatory Authorities (RAs) for approval to include elements of risk in start-up costs that cannot be mitigated by maintenance and insurance and where not reasonably anticipated in the investment decision and are not attributable to energy actions by the same unit in the Day Ahead Market (DAM), Intra Day Market (IDM) or Balancing Market (BM). The RAs shall issue a reasoned decision approving or refusing the inclusion of such costs.

1.1.16 The obligation to comply with this BMPCoP will come into force when both the relevant modifications have come into effect, and when part C of the Trading and Settlement Code (T&SC) comes into effect.

2. INTRODUCTION

2.1.1 The current policy underpinning the market power mitigation strategy in the Single Electricity Market (SEM) is partially based on bidding principles for generators. These bidding principles require generators to bid cost reflectively.

2.1.2 As part of the implementation of the bidding framework, the Regulatory Authorities (RAs) published in 2007 a Bidding Code of Practice (BCoP), (AIP-SEM-07-430), which was subsequently updated by the RAs, with the latest version of the BCoP published in 2014 (SEM-14-019).

2.1.3 In preparation for I-SEM Go-Live (i.e. May 2018), the SEM Committee reviewed current market power arrangements in SEM. As part of this review, the SEM Committee published an "I-SEM Market Power Mitigation Discussion Paper" (SEM-15-031), "Market Power Mitigation Consultation Paper" (SEM-15-094) and a "Market Power Mitigation Decision Paper" (SEM-16-024), which confirmed, inter-alia that the wording of the existing BCoP needed to be revised to take into account changes in the energy market arising out of I-SEM.

2.1.4 Subsequently, the SEM Committee published the "Offers in the I-SEM Balancing Market - Consultation Paper" (SEM-16-059). Following a review of responses, the SEM Committee published the "Complex Bid Offer Controls in the I-SEM Balancing Market - Decision Paper" (SEM-17-020), which detailed the SEM Committee's policy decisions regarding the bid offer controls (hereafter referred to as the Balancing Marketing Principles Code of Practice - BMPCoP).

2.1.5 Within decision paper SEM-17-020, the SEM Committee confirmed that:

i. the definition of SRMC will be based on per MW change in output (nominally determined over 1 MW range). The time period for the calculation of a generation unit's SRMC will be over one Imbalance Settlement Period (ISP). More precisely this is now identified as a 1 MWh change over an ISP in the revised BMPCoP – SEM-17-049.

ii. the recovery of Variable Operating and Maintenance (VOM) costs within the I-SEM Balancing Market (BM) will recognize that some maintenance costs may vary with the level of a generation unit's output on the basis that increased running may bring forward the next maintenance event for a generation unit. Therefore, generating units will be allowed to include their VOM costs when submitting their complex bid offer data in the I-SEM BM.

iii. foregone revenue will be permitted for inclusion in the complex bid offer data of energy limited generation units. However, elements of revenue such as capacity revenue are not permissible for inclusion in any generation unit's complex bid offer data in the I-SEM BM.

iv. in certain circumstances some DS3 products can be considered as forgone revenue. Consequently, in certain circumstances, a generation unit may discount or include DS3 revenue in its complex bid offer data.

v. provision for risk should not be eligible for inclusion in generating units complex bid offer data in the I-SEM BM. The SEM Committee did not consider that risk to plant and equipment, or risk of incurring penalties to be a marginal cost item. With regard to risk of damage to plant and equipment, the SEM Committee was of the view that this is best mitigated through appropriate maintenance and insurance. Additionally, the SEM Committee took the view that penalties should not be permitted for inclusion in generation unit's complex bid offer data in the I-SEM BM, as their inclusion would weaken the incentives for a generation unit to operate efficiently.

vi. the inclusion of long term GTC costs in the complex bid offer data of generation units will not be allowed. However, the commodity element of GTC costs will be permitted for inclusion in complex bid offer data, as will any GTC capacity purchased within day.

vii. the SEM Committee will separately consult upon the details of the new licence condition regarding the cost reflectivity of complex bid offer data. Additionally, a further consultation by the SEM Committee on the text of the Draft BMPCoP document for I-SEM was confirmed, which would also allow respondents an opportunity to comment on any related issues that have not been consulted on by the SEM Committee to date.

2.1.6 On the 13th April 2017, the SEM Committee published a "Balancing Market Principles Code Of Practice Consultation Paper (SEM-17-026), the "Consultation Paper", on the detailed wording of the draft BMPCoP (SEM-17-026a), in conjunction with the "Draft BMPCoP", to provide stakeholders with an opportunity to identify areas within the Draft BMPCoP that require further clarity. Additionally, respondents were requested to:

- identify any other related issues that should be considered by the SEM Committee prior to finalising the BMPCoP; and
- consider whether the Draft BMPCoP accurately reflects decisions made in the "Complex Bid Offer Controls in the I-SEM Balancing Market" decision paper (SEM-17-020).

2.1.7 The SEM Committee has prepared this "Balancing Market Principles Code of Practice Decision Paper", the "Decision Paper", following consideration of responses to the Consultation Paper.

3. RESPONDENTS' COMMENTS

3.1 OVERVIEW OF COMMENTS RECEIVED

3.1.1 This section provides a summary of responses to the Consultation Paper, which was published on 13th April 2017.

3.1.2 The SEM Committee received a total of 13 responses to the Consultation Paper. Of the 13 responses, several have been marked in whole or in part confidential. Table 3.1 below lists respondents who have provided publicly available responses, which can be obtained from the SEM Committee website.

Table 3.1: List of Respondents to Consultation Paper

BG Energy	Gaelectric
Bord Na Mona	Power NI PPB
CEWEP	Rusal Aughinish
Energia	SSE
Enerco	Tynagh
ESB GWM	Vayu

3.1.3 In general, many respondents addressed the specific text of the Draft BMPCoP and made suggested clarifications. Additionally, a significant volume of issues were raised by respondents that had been decided in previous SEM Committee decisions. Many of these comments pertained to decisions that had been published in SEM-17-020.

3.1.4 Section 3.2 of this Decision Paper summaries these comments in further detail.

3.2 SUMMARY OF RESPONDENTS' COMMENTS

Clarity as to the purpose of the BMPCoP

3.2.1 Some participants expressed a concern that the Draft BMPCoP does not clearly state its purpose and that if there are no stated principles applying to the document then the SEM Committee would effectively have a free rein in amending the document without regard to any overarching policy aim or purpose. A contrast was drawn with paragraph 4 in the case of the current BCoP, which sets out the aims of the BCoP.

Clarity as to the plants for which the BMPCoP applies

3.2.2 Clarity was requested by one respondent regarding whether the BMPCoP applies to plants that do not have a Reliability Option (RO), acquired through a Capacity Remuneration Mechanism (CRM) auction.

Fuel cost calculation methodology

3.2.3 Concerns were expressed that paragraph 18 of the Draft BMPCoP is unduly prescriptive regarding the choice of fuel price index, and in particular that there is no available real-time fuel price index that a licensee could use, which would meet the SEM Committee's requirements.

3.2.4 Further comments regarding the fuel cost calculation methodology expressed concerns that paragraph 18 of the Draft BMPCoP could be interpreted as a requirement to notify the RA every time changes are made to a fuel price methodology, and that this is disproportionate and serves no purpose in addressing market power. One respondent stated that this paragraph:

> *"…creates a significant burden for generators and the RAs. Moving from a general ex-ante requirement on offers to a constant reporting model creates the potential for a generator to be in breach of the BMPCOP and potentially its licence, not because its offers were not in line with the requirements but that no notification was made to the RAs when changing part of the fuel price build up. The cause could be as simple as an index not being published on a given day and having to use another…"*

Fuel transportation costs: double-counting, domestic gas, and non-gas fuels

3.2.5 Concerns were expressed regarding potential double-counting of fuel transportation costs, treatment of transportation costs for domestic gas, and regarding transportation costs for non-gas fuels. For example, one respondent expressed a concern with regards to paragraph 20 (incremental gas transportation costs of the Draft BMPCoP) that:

> *"…where a gas price index that is outside the island of Ireland is used in the fuel costs calculation method, then the method may include an element to account for relevant incremental GTC costs. BGE understands that at certain times of the year the GTC for the gas IBP already includes transportation costs. It is critical that provision is made in the BMPCOP to prevent the double-counting of GTC in such instances."*

3.2.6 This respondent suggests that this could be addressed for example by requiring that, GTC should only be included in the fuel costs calculation method where such GTC costs have not already been incorporated in the relevant fuel costs.

3.2.7 Two other respondents expressed a similar concern, with one in particular stating:

> *"…paragraphs 20/21 make no reference to transportation costs for indigenous gas and/or how this is to be reflected in generator's bids/offers. Furthermore, it is unclear why it only references gas transportation costs and does not go on here or elsewhere to describe the treatment of transportation costs for other fuels (e.g. coal or oil). Again, given the purported focus of this document is to provide clarity and detail to licensees, this section is unclear and does not assist licensees in submitting bids/offers."*

Different fuels for start-up and incremental operation

3.2.8 A suggestion was made regarding greater clarity of eligible cost of start-up fuels in the case of plants that use different fuels for start-up versus incremental operation. In particular, with regards to paragraph 25.a (cost of fuel required for start-up) of the Draft BMPCoP, one respondent stated:

> *"Regarding the cost of fuel required for start-up, paragraph 25(a) of the proposed BMPCoP states that this "should use the same calculation method as the incremental fuel costs outlined in paragraphs [16] to [18], including the same price index". This prescriptive drafting fails to recognise that a number of generating units, including those at Moneypoint, use different fuels for start-up and incremental operation. Moreover,*

where multiple start fuels are used, the actual blend deployed will typically vary depending on the conditions at the time."

Clarity regarding the relevant time period within which Opportunity Cost is determined

3.2.9 Some respondents stated that paragraphs 5, 6, and 7 of the Draft BMPCoP refer to eligible costs evaluated over the ISP concerned, whereas paragraph 32.a of the Draft BMPCoP references Opportunity Costs in the context of the prevailing market value or spot price of the cost item for an operating *day*. Clarity was requested regarding the reference to the time period of an ISP in the earlier paragraphs, as compared to the reference to a time period of a day in paragraph 32.a.

3.2.10 Further, it was noted that the Commercial Offer Data (COD) is represented at any time by a single three-part offer curve – not a separate three-part offer curve for each remaining ISP of the operating day. A concern was expressed regarding the issue of what value should exist in the COD, if the value is expected to change over the course of the day.

3.2.11 One respondent described the issue as follows:

> *"A further issue is that the complex bids are not defined for each individual imbalance period but generators must submit a single curve that applies for the remainder of the trading day. We have highlighted above that costs change across the trading day and not just spot prices but also tariffs and an example is gas transportation charges. In this example, the cost of gas transportation for the 1 October trading day will have low capacity costs for the period from 11pm to 5am but which then have a step increase from 5am when the multipliers increase to be the October multipliers. As a result there is no single "value" that covers all periods in the remainder of the day for which the complex bid offer data must cover."*

Objections regarding "three bilateral offers"

3.2.12 With regards to paragraph 32.b ("…three bilateral offers") of the Draft BMPCoP some respondents are of the view that the level of prescription is unworkable. For example, one respondent stated:

> *"For costs such as VOM this isn't possible as generators would generally have little choice as to who to work with and so three offers just wouldn't be possible. Other costs that could come into this category could be peat or biomass or the specificities of DSU offers."*

Definition of Relevant Output Level

3.2.13 Some respondents considered that there is an inconsistency between paragraph 7 and paragraph 46 of the Draft BMPCoP regarding the reference to the Relevant Output Level. For example, one respondent stated that:

> *"The reference to "Relevant Output Level" in paragraph 7 is inconsistent with the definition provided in paragraph 46 of the proposed BMPCoP. One refers to the change from a level and the other to a change to a level. This is unhelpful and unclear, and does not assist licensees in submitting bids/offers."*

3.2.14 Similarly another respondent stated, with regards to paragraph 7 of the Draft BMPCoP, that:

> *"This paragraph requires that the SRMC for bids is to be determined by the cost of increasing (or decreasing) output by 1MWh from the Relevant Output Level (ROL), i.e if the ROL is 100MWh then the cost of increasing output from 100MWh to 101MWh. However this is contradicted by the definition of "Relevant Output Level" which is defined as the level of output that is reached when an offer is accepted (i.e. if the ROL is 100MWh then this is the movement from 99MWh to 100MWh which is different to how it is described in paragraph 7."*

The decision to exclude any costs justified on the basis of "risk"

3.2.15 A number of respondents disagreed with the SEM Committee decision in SEM-17-020 to exclude provisions risk as an Eligible Cost Item, with one respondent stating that with the exception of the exclusion of risk it considers the changes to market power mitigation proposed for the I-SEM as being relatively minor.

3.2.16 Other responses focused primarily on the exclusion of risk from start-up costs, with one submission, providing on a confidential basis, empirical evidence purporting to show that increased start frequency is a clear driver of increased outage rates. This respondent argued that absent an allowance for risk in the start-up cost submission, the dispatch optimisation process will be inefficient as the actual costs of shutting down and starting units will not be recognized in the dispatch optimisation. Another respondent argued that excluding risk from start cost submissions will lead to increased cycling.

3.2.17 A further response claimed that the risk of being dispatched outside of normal operating limits should be able to be reflected in bids and offers as it is of the view that the statement in SEM-17-020 that "*The I-SEM, just like the SEM, does not contain provisions for generators to offer such emergency capacity, and the SEM Committee's expectation is that the TSO will not dispatch generators above their normal operating limit in the BM*" is incorrect.

3.2.18 A number of responses all stated that insurance policies are not available to cover all the risks associated with equipment damage as available policies all have exclusion periods that would not apply to typical outages. One respondent in particular stated that risk is a variable cost as the consequence of risk is occasioned by operation and a legitimate SRMC. This respondent further stated that if risk is excluded as an Eligible Cost Item then risk costs must be included in the Best New Entrant (BNE) cost, and that the rationale for excluding risk is both arbitrary and unjustified.

3.2.19 A number of respondents also took issue with the exclusion of penalty costs. One respondent's primary concern in this area related to Generator Performance Incentives (GPI), where other respondents appear to be concerned with penalties associated with gas overruns and intra-day gas price variations. One respondent argued that the RO obligation risk resulting from TSO scheduling decisions should also be allowed in incremental and decremental bids in complex offers.

Objections that the previous decisions and BMPCoP have moved away from a principles based approach to being unduly prescriptive.

3.2.20 Many respondents stated that the I-SEM market power mitigation strategy is a move away from a principles-based approach to a more prescriptive approach. For example, one respondent stated that "*in contrast with the I-SEM proposals, the successful approach in SEM can be characterised broadly as a principles based approach that deliberately avoids a prescriptive approach, favouring flexibility for licensees to comply within a general rubric promoting competition and providing the appropriate opportunities for cost-recovery*."

3.2.21 This view was shared in a number of respondents who expressed the view that the proposed strategy is a move away from a principles based approach. Their concerns were expressed in two general ways. First there is a concern that some of the specific proposals are overly prescriptive. Second, there is a more general concern that as the Draft BMPCoP does not explicitly re-iterate the principles that are currently in the license, there is a lack of guidance as to the intent of the BMPCoP and how it may evolve in the future.

Objections to the definition of the SRMC as being the change in cost associated with producing an added MWh over the ISP.

3.2.22 Some respondents have objected to the definition of SRMC in the context of the reference to a 1 MWh change in output (paragraph 7 of the Draft BMPCoP). For example, one respondent stated that their primary concern with the Draft BMPCoP language related to the cost metric used to define the incremental cost of increasing or decreasing output. This respondent stated that requiring costs to reflect the change in total eligible costs for a 1MW change in output could have unintended consequences and influence market participant behaviour such that costs are applied in a way that could drastically increase Dispatch Balancing Costs ("DBCs"), and that this could have knock-on negative impacts for consumers.

3.2.23 Paragraph 7 of the Draft BMPCoP sets out that the SRMC (at a Relevant Output Level) shall be calculated as the change in total eligible costs for a 1 MWh change in output relative to that Relevant Output Level. The same respondent stated that:

> *"…the proposed drafting would not result in cost-reflectivity and suggested that the cost metric used to define appropriate incremental costs should instead be defined in terms of the incremental cost associated with altering output as specified in the relevant offer. In the case of energy offers, this would imply the incremental costs of increasing or decreasing output by the specified volume for the specified Imbalance Settlement Period."*

3.2.24 Two respondents believed there is an inconsistency between the SEM Committee's requirement for price-quantity pairs to be cost-reflective (paragraph 5 of the Draft BMPCOP) and for them to be monotonically increasing (paragraph 9 of the Draft BMPCOP).

Objections to the decision to not allow longer term non-variable GTC costs as an Eligible Cost Item.

3.2.25 One respondent objected to the SEM Committee's decision to not allow long term gas costs to be reflected in bids. It stated that this will place Northern Ireland (NI) generators and customers at a disadvantage as some gas transportation costs for NI generators are only available on an annual basis. This respondent appeared to argue that if these costs must be recovered through the CRM for units in NI, it will disadvantage units in NI in that market and potentially lead to reduced security of supply.

Claims that the mitigation measures while directed at only non-energy actions will apply more broadly as complex bids will be used to optimize the dispatch.

3.2.26 Decision Paper SEM-17-020 is clear that ex ante bid controls are intended to apply primarily only to non-energy actions as the Day Ahead Market (DAM), Intraday Market (IDM) and Balancing Market (BM) for energy actions are expected to be competitive given factors such as the continuation of Directed Contracts and REMIT. Some respondents take the position that despite this intention, the BMPCoP applied to complex offers will more broadly affect markets.

3.2.27 One respondent stated that they remain "*steadfast of the view that the bidding controls applied to three part offers will impact right across the energy market. This will occur through the TSOs' scheduling software which will optimise the system based on three part offers rather than simple offers until 30 minutes before real time. This will also occur as a result of NIV Tagging and SEM Committee imposed settlement rule which result in dampened prices and NIV tagged actions, which are not actually subject to an operational constraint being settled based on three part offers*."

3.2.28 Another respondent takes a similar view, quoting from Section F, of the Trading & Settlement Code (T&SC), on the conditions on which simple and complex bid offer data will be applied. This respondent argued that these rules in conjunction with a five-minute settlement period will result in a large volume of NIV tagged energy to which complex bids are applied. Another respondent took a similar but more narrowly expressed view, arguing that NIV tagged actions are energy actions and should not have complex bids applied.

Claims that the mitigation process will result in units that are required to reliably serve load not being provided an opportunity to recover their full costs.

3.2.29 Some respondents expressed concerns with the Draft BMPCoP, the broader concept of ex ante bid control and the design of the I-SEM, arguing that these elements could render them unable to recover their costs. One respondent stated that units providing needed flexibility that are not in constrained areas may have inadequate revenue opportunities. One response expressed the view that the guiding principle of generator cost recovery under the right competitive environment contained in the SEM BCoP should be retained in the BMPCoP. Another respondent argued that:

i. There is no uniquely defined "*competitive market price*" for imperfectly competitive markets that are characterized by significant constraints and a lumpy, long-term investment cycle; and

ii. The SEM Committee appears to assume that the market exhibits a surplus of generation capacity and hence is oversupplied, and that SRMC is therefore the appropriate benchmark. However, this is often and manifestly not the case in the some areas of the I-SEM.

3.2.30 In the same vein, the same respondent argued that the "…*SEM Committee's interference in markets to bring about a specific outcome (i.e. wholesale prices lower than in SEM) instead of* *promoting effective competition to the benefit of customers and allowing all generators the opportunities to finance their licenced activities; i.e. recover their total costs*", will lead to units being denied legitimate compensation opportunities.

3.2.31 Finally, in relation to markets providing inadequate revenue opportunities, one respondent stated that "*The reference in SEM/17/020 to the possible need for a mechanism to make additional payments to generators to address local system service requirements or local security of supply concerns, highlights a clear failure in the I-SEM market design. It is the market design that is giving rise to this risk of market failure; a proper market design should seek to alleviate such market failures*."

Objections related to the nature of change management provisions

3.2.32 Some respondents have stated that they are not in favour of the governance arrangements proposed, in particular moving content from the licence to a subsidiary document. Responses to the Consultation Paper have also raised concerns with the proposed change management process in the Draft BMPCoP. For example, one respondent stated their belief that:

> *"…a mechanism should be introduced whereby licensees can call upon the SEM Committee to hold a timely consolation (sic) on a the treatment of a particular cost-item or items that may or may not be already included in the list of Eligible Costs."*

3.2.33 Other respondents expressed concerns regarding who would be involved in the process of change. One respondent stated that the existing provision for change management:

> *"…only makes reference to consultation with holders of generation licences when there are other participants such as PPB who participate as Intermediaries and are obligated to comply with the code in accordance with their licence. All parties who have an obligation to comply with the code should be consulted."*

4. SEM COMMITTEE RESPONSE

The SEMC's statutory duties and approach to decision making

4.1.1 The SEM Committee notes that a number of the points made in response to the Consultation Paper, essentially, restated arguments made previously that the SEM Committee's approach to the BMPCoP was not in line with statutory and / or wider legal duties.

4.1.2 In SEM-17-20 (in particular, see section 3, section 10.3 and Annex B), the SEM Committee explained at length the applicable statutory duties and outlined the SEM Committee's aims and approach in developing its policy on complex bid offer controls for I-SEM within the context of that statutory framework (as well as a number of wider legal obligations that had been raised by market participants, e.g. competition law and property rights).

4.1.3 Consequently, the SEM Committee does not intend to restate in general terms the statutory and wider legal framework which applies, or respond to repetitive comments on its statutory legal requirements, as this has already been done (as outlined above, notably in SEM-17-20).

Clarity as to the purpose of the BMPCoP

4.1.4 The SEM Committee agrees that it is appropriate for the BMPCoP to have a statement as to its aims, and a new paragraph (i.e. paragraph 2) has been added to the revised BMPCoP (SEM-17-049) to reflect this.

4.1.5 However, in contrast with the existing BCoP, the SEM Committee believes that the aim should simply be stated as one of securing that complex bid offer data reasonably reflect SRMC and, thus, helping to ensure that generators cannot exercise market power. References to appropriate compensation in conjunction with the CRM are no longer necessary due to the reduced scope of the BMPCoP in the I-SEM (as compared to the BCoP in the SEM), due to the market clearing-based nature of the CRM (as compared to the CPM in the SEM) and due to the fact that ensuring compensation for efficiently incurred costs is incumbent on the RAs and need not be specifically stated in the BMPCoP.

Clarity as to the plants for which the BMPCoP applies

4.1.6 The BMPCoP applies to all generating sets and units operating in the I-SEM, whether they hold an RO or not. The BMPCoP is an instrument of market power mitigation, and the RO status of a generating set or unit does not have an impact on whether or not a generating set can exercise market power in non-energy actions. Paragraph 2 of the Draft BMPCoP sets out that a licensee's offers to the market must be made in accordance with the BMPCoP, so no further elaboration is required. Paragraph 2 of the Draft BMPCoP is not conditional on the RO status of a generating set or unit.

Fuel cost calculation methodology

4.1.7 The SEM Committee does not share the view that the BMPCoP is unduly prescriptive regarding the choice of fuel price index. The BMPCoP is clear that the Licensee shall determine its own fuel cost calculation method, including its chosen fuel price index. The BMPCoP does not place restrictions on how the Licensee calculates its fuel cost or the price index it uses, except of course, that it should be cost reflective.[1] The result should represent the Licensee's best indicator of its expected eligible fuel costs. Given that the COD can be updated close to real time in the BM, it is not expected that significant systematic and directionally-biased differences would or should exist between actual fuel prices incurred by the Licensee, and the fuel price measure it chooses to use for indexation purposes.

4.1.8 The SEM Committee does not share the view that the proposed wording of paragraph 18 of the Draft BMPCoP would create the significant burden in the form of a "*constant reporting model*" as one respondent suggested. For example, to address the potential issue presented of an index not being published on a given day, the fuel price methodology could specify in advance the process that would be followed on any day in which the usual data is not available.

Fuel transportation costs: double-counting, domestic gas, and non-gas fuels

4.1.9 The SEM Committee agrees that gas transportation costs should not be double-counted and believes that the current wording of paragraph 20 of the Draft BMPCoP (paragraph 21 of the revised BMPCoP) does not allow such double-counting to occur. Paragraph 20 of the Draft BMPCoP states that when a gas price index outside the all-island market is used (e.g. an NBP price index), the incremental gas transportation cost related to bringing the gas to the relevant wholesale pricing point in the all-island market should be added. If the gas price index used refers to a pricing point which is already within the all-island market (i.e. IBP) then this additional transportation cost (i.e. from NBP to IBP) is not needed (exit gas transportation costs related to delivering the gas from the all-island wholesale pricing point to the point of consumption can still be included as mentioned in paragraph 21 of the Draft BMPCoP – paragraph 22 of the revised BMPCoP).

4.1.10 In relation to the application of transportation costs to domestic gas, the SEM Committee notes that the gas used for electricity generation should be valued based on its Opportunity Cost in accordance with paragraphs 30-33 of the Draft BMPCoP (paragraph 34-37 of the revised BMPCoP).

4.1.11 The SEM Committee does agree that greater clarity and detail should be achieved with reference to eligible costs relating to the transportation of other fuels. Accordingly, a new paragraph (i.e. paragraph 23) has been inserted to the revised BMPCoP regarding the use of non-gas fuels and other modifications have been made to accommodate non gas fuels. Subsequent references to gas and GTC have been updated to refer to fuel and Fuel Transportation Cost (FTC).

Different fuels for start-up and incremental operation

4.1.12 The SEM Committee agrees that greater clarity should exist for the case of the eligible cost of start-up fuels in the case of plants that use different fuels for start-up versus incremental operation. Accordingly, the wording of paragraph 25.a of the Draft BMPCoP (paragraph 27.a of the revised BMPCoP) has been modified to reflect the possibility that the start-up fuel might be different than the fuel used for incremental operation, and that it might be a blend of fuels.

[1] As set out in Section III of the BMPCoP.

Clarity regarding the relevant time period within which Opportunity Cost is determined

4.1.13 The SEM Committee agrees that better consistency should exist between the Draft BMPCoP paragraphs 5-7 and paragraph 32 of the Draft BMPCoP, regarding the relevant time period over which Opportunity Cost is determined. Accordingly, the wording of both paragraphs 6 and 36.a in the revised BMPCoP have been updated to avoid the appearance of inconsistency in this respect.

4.1.14 Regarding the point that was made that complex bids are not defined for each individual ISP but rather generators must submit a single curve that applies for the remainder of the trading day, the SEM Committee notes the following:

i. The curve can be updated at any time up to the opening of the BM, 1 hour before each trading period. This provision allows the curve to be updated as any eligible costs change throughout a day.

ii. Notwithstanding the preceding point, it is accepted that the detailed market rules do not make provision for a separate set of COD for each trading period in the remainder of an operating day. To the extent that: a) the TSOs might look ahead more than 1 hour in the evaluation of some COD; *and* b) some eligible costs might be expected to change over the course of the remainder of the trading day, then it will not be possible to exactly align the cost information presented to the TSOs (via the COD) with the true underlying expectation of eligible cost of the generating set or unit. This is inherent in the detailed market rule and IT design, and is not a point the BMPCoP can or should address. The BMPCoP does allow flexibility, so that the participant shall determine the appropriate and relevant time period concerned over which to calculate Opportunity Cost within a trading day, and thus the participant shall determine the most representative cost information to be presented to the TSOs via the COD in the event that Opportunity Costs are expected to change during the day. However, paragraph 36.a of the revised BMPCoP has been edited to make this clearer.

Objections regarding "three bilateral offers".

4.1.15 Paragraph 32.b of the Draft BMPCoP relates to the determination of Opportunity Cost in a situation where no recognised and generally accessible trading market exists. The SEM Committee accepts that there might be some situations in which it is impossible to obtain three bilateral offers, but the SEM Committee emphasizes that paragraph 32.b of the Draft BMPCoP is merely a backstop provision for paragraph 32.a, and it is envisaged that in most or all situations the Opportunity Cost will be established via a trading market. The concept of Opportunity Cost applies in this context when operation and maintenance costs will be incurred as a direct function of MWh output (i.e. VOM). Generally accessible trading market prices should be applicable for most or all VOM cost categories such as labour, parts, consumables, and others. In any event the body of paragraph 36 of the revised BMPCoP allows for alternative approaches to apply where there is good cause not to apply the approaches of paragraph 36.a or paragraph 36.b.

4.1.16 Accordingly, paragraph 36.b of the revised BMPCoP has not been modified.

Definition of Relevant Output Level

4.1.17 The SEM Committee does not agree that the definition of Relevant Output Level in paragraph 46 of the Draft BMPCoP is inconsistent with its use in paragraph 7. Paragraph 7 of the Draft BMPCoP refers to changes relative to a Relevant Output Level which are either positive or negative. Paragraph 46 of the Draft BMPCoP states that a Relevant Output Level represents the level of output that a generation set or unit or Demand Side Unit reaches when its corresponding incremental offer or decremental bid is accepted.

4.1.18 Accordingly, the definition of Relevant Output Level has not been modified in the revised BMPCoP.

The decision to exclude any costs justified on the basis of "risk"

4.1.19 In SEM-17-020, the SEM Committee outlined its rationale for the exclusion of costs related to increased risk of plant and equipment failure as a result of the generation unit's running regime within the BMPCoP's list of Eligible Cost Items.

4.1.20 Such rationale included, inter-alia:

i. the ability of generators to recover maintenance costs (fixed maintenance costs as an eligible cost category in the CRM and the inclusion of variable maintenance as an Eligible Cost Item in the BMPCoP) which can be used to minimise the risk of plant and equipment failure as a result of its running regime;

ii. the use of insurance to mitigate the general risk of plant and equipment failure, which a prudent generator would be expected to take out to cover such events. This fixed maintenance costs is an eligible cost category in the CRM; and

iii. the allowance for risk of outages that was priced into the investment decision and in the rate of return from the generation unit.

4.1.21 Notwithstanding the above, a number of responses have stated that a generation unit may face a "residual risk" as a result of cycling that would not be mitigated by regular maintenance and insurance cover or attributable to energy actions by the same unit in the DAM, IDM or the BM. The SEM Committee acknowledge that damage to plant and equipment can be a significant cost that is occasioned by an operational action (a start-up or a subset of start-up categories, i.e. cold warm or hot start ups) and that this residual risk could be considered a SRMC associated with that action.

4.1.22 However, the SEM Committee remain concerned that the costs associated with this residual risk are ambiguous, are difficult to verify and are potentially subject to overstatement by generation units that know they will likely be frequently called on to start out of merit. The SEM Committee indicated that in developing the BMPCoP it will build on experience gained in the SEM and one element of that experience is that adjudicating a reasonable level for a cost justified based on risk is difficult.

4.1.23 However, in finalising the BMPCoP, the SEM Committee will allow that costs associated with the residual risk of potential damage to plant and equipment as a result of starts, or a sub set of starts, may be reflected in that category of start-up component of complex offers to the extent that they cannot be mitigated by maintenance and/or insurance, were not (and could not reasonably have been) anticipated in the investment decision or are not attributable to energy actions by the same unit in the DAM, IDM or the BM. However, in light of concerns with respect to potential abuse, a process has been developed for the ex-ante RA approval of such costs. See paragraph 28 of the revised BMPCOP.

4.1.24 The RAs do not agree with responses asserting that residual risk costs should be allowed for operation outside of normal operating limits as the RAs do not believe that the I-SEM (like the SEM) contains any provisions for mandatory emergency operation, other than system service agreements with the TSOs or grid code requirements.

4.1.25 Further, with the introduction of administrated scarcity pricing, emergency situations are likely to coincide with requests for emergency operation and units that operate at levels above those bid in the Price Quantity (PQ) pairs in response to a TSO request will likely receive scarcity payments for such operation.

4.1.26 With respect to excluding fuel price risk from daily volatility or penalties the SEM Committee believes that the proposed BMPCoP is appropriate. Respondents have not offered further evidence that would change our view expressed in SEM-17-020 that intra-day fuel price risk is symmetrical nor that penalties should be an Eligible Cost Item.

4.1.27 Finally, although not included in the discussion of risk related costs, one respondent argues that "*Given a scheduling decision by the TSO can expose a generator to the large costs associated with not meeting its RO obligation, it is necessary that such costs (or a risk-based proportion thereof) are included in the generator's incremental /decremental complex bids/offers, if the bids/offers are to be cost-reflective.*" No explanation is provided of how this could be done or how it would apply. Units directed to start or increase generation for a non-energy reason, would have a reduced RO exposure and not an increased RO exposure. Additionally it is likely that in a scarcity event all generation will likely be needed to meet expected demand.

Objections that the previous decisions and BMPCoP has moved away from a principles approach to being unduly prescriptive

4.1.28 The SEM Committee does not agree with the objections raised regarding a move away from a principles based approach. The SEM Committee also notes that some respondents recognize this, with one respondent stating that while the I-SEM market power mitigation strategy is a move away from the "successful" SEM approach, it does acknowledge that "*it is possible (with the exception of the exclusion of Risk) to characterise these decisions as being relatively minor in the overall context of the changes proposed in the market under I-SEM*".

4.1.29 The SEM Committee does not view the additional detail provided in the BMPCoP as a move away from principles. The details in the BMPCoP are intended to clarify and make uniform how a select list of cost items are expected to be treated and to provide clarity and direction to generators with respect to those items. Generators will still maintain flexibility when calculating their COD, such as the determination of their fuel cost calculation method i.e. paragraph 18 of the Draft BMPCoP (paragraph 19 of the revised BMPCoP).

4.1.30 The SEM Committee have previously stated that there are issues with the existing arrangements, for example in relation to the transparency of which costs are appropriate to be included and which are not, and these issues would be expected to continue. The SEM Committee is of the view that added clarity would be beneficial and is not inconsistent with a principles-based approach.

4.1.31 The SEM Committee notes that no respondent provided any specific example of a marginal cost that is inappropriately missing from the eligible cost category (with the exception of residual risk). Furthermore one respondent, despite protesting what it calls an exhaustive list of eligible costs items acknowledges that except for the cost of risk exclusion, changes are minor.

4.1.32 Additionally, the SEM Committee notes that principles can be expressed in the form of a specified list of eligible costs and doing so will enhance clarity over what reasonably constitutes an SRMC and reduce the potential for abuse by generators in a position to exercise market power. If that list needs to be expanded, due to changed circumstances, a new valid component of SRMC can be added to the list of eligible costs components, following consultation of the BMPCoP.

4.1.33 Speculative concerns that the SEM Committee will not act reasonably and promptly to recognize needed changes to eligible costs is not a reason to forgo the benefits of clarity that such a list provides. Similarly, claims that the RAs are unsuited to and incapable of anticipating changes in technology and business practices that may evolve and for that reason elaboration of eligible costs will harm generators as the list of such costs will lag the market reality are unfounded. This fails to recognize that the RAs are not the sole party initiating changes that may be needed to the list of eligible costs. As technology and business practice evolve, the SEM Committee expects that generators would propose necessary changes and the SEM Committee would review and decide upon those changes.

Objections to the definition of the SRMC as being the change in cost associated with producing an added MWh over the Imbalance Settlement Period

4.1.34 The SEM Committee has considered again the concerns expressed by respondents with regards to the reference to 1 MWh in the definition of SRMC, and the relationship between SRMC and the COD. The SEM Committee believes that these concerns, relating to paragraph 7 of the Draft BMPCoP, are adequately addressed in the context of the existing wording of paragraphs 6, 8 and 9 in the Draft BMPCoP (paragraphs 7, 9, and 10 of the revised BMPCoP).

4.1.35 To clarify, it is the COD that is utilized by the TSOs for system operations purposes and, within the constraints imposed by the monotonically-increasing format required, the COD should be that which best represents the rate of incremental eligible costs over the relevant range of generation set or unit capacity. Rather than being free to choose any spacing between PQ pairs they submit in the BM, participants are required to establish SRMC at representative intervals, and then fit the COD function which is the best representation of SRMC curve. The SEM Committee is of the view that these requirements are adequate in order to require that the COD adequately reflects incremental eligible costs.

4.1.36 Accordingly, paragraph 7 of the Draft BMPCoP has not been modified.

4.1.37 Regarding one respondent's comment that paragraph 9 of the Draft BMPCoP suggests that costs should be transferrable (between the price-quantity component and the start-up/ no load components) "*since that is the only way to achieve a best fit*", this is not the case. Eligible start-up costs and price-quantity components shall be calculated such as to ensure that the COD equates to the best representation of the SRMC, while meeting the monotonically increasing requirement. This does not represent a licence to freely transfer costs between bid/offer components be transferred into the price-quantity component, or vice versa.

Objections to the decision to not allow longer term non-variable gas transport costs as an Eligible Cost Item

4.1.38 The SEM Committee's decision paper (SEM-17-020) confirmed that gas transportation products purchased ahead of the trading day are not a short-run cost, but rather a fixed cost for a generating unit. Respondents' comments do not challenge this decision but relate to potential impacts on the CRM and security of supply in NI. These issues are outside the scope of the BMPCoP. Additionally, the SEM Committee notes that one respondent stated that it would prefer that the text not say that these short run gas transportation costs "may" or "can" be included in bids but rather should say that such costs are required to be included in bids to avoid the potential for predatory pricing. Given the speculative nature of concerns over predatory pricing, the SEM Committee does not see any compelling need to change "may" and "can" to a requirement, but has in some instances changed may to shall in BMPCoP where it was clearly anticipated that such a cost would be applicable.

Claims that the mitigation measures while directed at only non-energy actions will apply more broadly as complex bids will be used to optimize the dispatch

4.1.39 The SEM Committee has a two-part clarification to the responses on this topic. Both parts of the response were set forth in decision paper SEM-17-020, but will be re-iterated herein.

4.1.40 Firstly, with respect to the claim that complex offers will impact energy markets more broadly, the RAs repeat that "*The proposed BMPCoP for I-SEM bids and offers will not be applied across all the I-SEM markets, but rather primarily non-energy actions in the balancing market, where units have been tagged and flagged by the TSOs for system reasons. Any unit that has been tagged and flagged will not be able to set the BM price and will be settled at the higher of its complex bid offer data and the BM price. The only instance where the SEM Committee can see that the complex bid offer data affect price formation is if units do not submit any simple bids and offers. In this instance units would be taken on their complex bids and offers*."

4.1.41 The SEM Committee notes that even if the actual market dispatch is optimised as has been argued it will be based on complex bids and offers and volumes traded up until 30 minutes prior to the ISP, the DAM and IDM prices will have already been settled and not adjusted to reflect the optimisation. Moreover, energy balancing prices will remain based on simple bids unless tagged as non-energy actions, NIV or early energy actions. Hence, while it may well be correct that the actual dispatch will in part reflect the complex bids and offers, the pricing impact of those offers will be limited to specifically tagged actions and in all such cases units will be remunerated at the higher of the BM price or a value based on their complex offer.

4.1.42 Secondly, with respect to any indirect impact that the complex offers may have on energy markets or any impact on NIV tagged dispatch instructions, there is no harm. As explained in decision paper SEM-17-020, “*The purpose of the bids and offer principles, as laid out in the BMPCoP, is to allow replication of the type of offers that would be expected from generators that operate in a competitive market. The SEM Committee has deemed the DAM and IDM to be competitive, therefore we do not believe the three-part bids and offers price to be lower than that what would be expected in the DAM and IDM*.”

Claims that the mitigation process will result in units that are required to reliably serve load not being provided an opportunity to recover their full costs

4.1.43 The principal I-SEM energy markets are the DAM, IDM and BM. There are no ex-ante bidding controls in these markets. Bidding controls will apply primarily to non-energy actions such as out of merit dispatch to resolve locational or system constraints. It is the SEM Committee’s view the ex-ante bidding controls are far less pervasive in the I-SEM than in the SEM. Additionally, in the BM, generation units are paid the higher of market or their own marginal cost. In both the SEM and the I-SEM, generating units that are constrained on for non-energy reasons (operated out of merit) are paid their own marginal costs.

4.1.44 The SEM Committee notes that one respondent indicated that units required for local security of supply reasons are entitled to face a revenue opportunity that is based on something other than the higher of the market clearing prices for energy and capacity applicable to the all-Island market or their own going forward costs -- that is a revenue opportunity to recover their own total cost. However, no rationale is provided as to why the higher of the market clearing prices for energy and capacity applicable to the all-Island market or their own going forward cost is not appropriate compensation.[2]

4.1.45 The SEM and the I-SEM have not been designed to provide localised market prices. With respect to local system service requirements, in decision paper SEM-17-020, the SEM Committee noted in paragraph 3.5.10 “*that there is a possibility that a generator which is critical to meet local system service requirements but not local capacity requirements does not get awarded a RO. This could happen if it has high net going forward costs, and reflects those costs in its CRM auction offer. The CRM auction constraints do not reflect local system service requirements, and if the bidder is out-of-merit in the unconstrained CRM merit order, and not required for local capacity reasons, it will not receive a RO. After the auction, the TSOs will need to identify whether there are any local system service requirements that are not met by generation plants that are expected to remain available for the following capacity year, and identify economic and efficient solution to those issues*.”

4.1.46 In paragraph 3.5.11, the SEM Committee stated that “*Additionally, consistent with the SEM Committee decision set out in the Locational Issues decision (SEM-16-081), a locational need capacity requirement would only be included in the CRM mechanism where the need is “clear and significant*”. There remains the possibility that following the auction, the TSOs identify an unexpected localised security of supply issue - one that did not meet the definition of “clear and significant” before the CRM auction, but which the TSOs judge, following the results of the auction, may be a material risk to local security of supply. Whilst this is not expected, there

[2] Actually a unit awarded an RO in the CRM that is needed for local capacity purposes will receive the higher of the all Island capacity clearing price, their own going forward costs or the Existing Capacity Price Cap. The all Island capacity clearing price and the Existing Capacity Price Cap may both be higher than a unit’s total cost.

remains the possibility that a targeted contracting mechanism may need to be put in place by the TSOs to address such an eventuality."

Objections related to the nature of change management provisions

4.1.47 The SEM Committee reaffirms its decision and rationale provided in SEM-17-020 to establish a generic generator and supplier licence condition, which would require, inter-alia, generators and suppliers to comply with the I-SEM BMPCoP document.

4.1.48 The SEM Committee agrees that elaboration of the draft change management provisions of the BMPCoP document is appropriate. Consequently, section VI of the revised BMPCoP has been elaborated accordingly.

5. SEM COMMITTEE DECISIONS

5.1.1 The following is a summary of specific wording changes that will be made to the Draft BMPCoP and incorporated into the revised BMPCoP. SEM Committee decisions that result in no changes to the Draft BMPCoP document are not listed below. Other minor edits such as typos are also not listed below.[3]

5.1.2 The SEM Committee has decided that the costs of risk to plant and plant equipment from start-up will require regulatory approval. The following requirements will also apply to a generator claiming such costs:

a. a statistical or actuarial study validating the level of cost sought to be included; and

b. a certificate from an officer of the applicant that such costs:

i. are included in a similar manner for all similar units operated by the Licensee and any of its affiliated companies;

ii. cannot be mitigated by maintenance and/or insurance;

iii. were not, and could not reasonably have been, anticipated in the investment decision for the relevant generation set or unit; and

iv. are not attributable to energy actions by the same set or unit in the Day Ahead Market, Intra Day Market or the Balancing Market.

[3] For example:

- One respondent noted that paragraph 6 of the Draft BMPCoP refers to SRMC being measured in '€ or £/MWh' and believed that this should be '€/MWh or £/MWh'. This suggested edit has been accepted, in paragraph 7 and elsewhere of the revised BMPCoP.

- One respondent noted with regards to paragraph 13 of the Draft BMPCoP that: "The drafting states that the No Load cost 'shall reflect the fuel cost…'. The SEM Committee notes that there are additional costs in addition to fuel, including for example, other costs identified as Eligible Cost Items including fuel transportation and emissions costs and other consumables, and had amended the Draft BMPCoP accordingly.

- One respondent noted that paragraph 16 of the Draft BMPCoP refers to fuel costs that are "incurred" and highlighted that these costs can only be predictions of the costs that will be incurred since the actual cost will only be known after the event. The SEM Committee acknowledges this, and has amended the Draft BMPCOP accordingly.

5.1.3 The RA shall issue a reasoned decision approving or refusing the inclusion of such costs. A Licensee holding such an approval may request the RA to revise the level of costs approved for inclusion and the provisions of sub-paragraphs (28a) and (28b) shall apply to any such request.

5.1.4 Regarding the over-arching purpose of the BMPCoP, a new paragraph (i.e. paragraph 2 of the revised BMPCoP) has been added which states: "*This Code makes provision for the purpose of securing that complex bid offer data reasonably reflect the short run marginal cost of operating the generation set or unit to which they relate, thereby facilitating the efficient operation of the I-SEM Balancing Market by helping to ensure that generators cannot exercise market power in the generation of electricity on the island of Ireland or any part thereof.*"

5.1.5 Regarding the fuel cost calculation methodology, the last sentence of paragraph 19 of the revised BMPCoP has been modified to clarify that: "*The Licensee may change its chosen fuel cost calculation method from time to time and shall inform the Regulatory Authority of its decision in advance including the motivation for any change*."

5.1.6 Regarding non-gas fuels, references to gas and GTC have been updated to refer to fuel and FTC.

5.1.7 Regarding non-gas fuels, paragraph 23 has been inserted into the revised BMPCoP, clarifying that *"the fuel cost calculation for fuels other than gas may include the cost for the delivery of fuel to the plant and the fuel handling costs incurred within the plant".*

5.1.8 Regarding the use of different fuels for start-up versus incremental operation, paragraph 27.a of the revised BMPCoP has been updated and elaborated so as to clarify: *"The fuel cost element of the start-up costs component shall cover the units of fuel required to start-up the set or unit at the request of the Transmission System Operator. It should use the same calculation method as the incremental fuel costs outlined in paragraph 19, including (if applicable), the same price index, if the start-up fuel is the same fuel type as that used for incremental production. In the event the start-up fuel, or blend of start-up fuels, is different than the fuel(s) used for incremental production then the provisions of paragraph 19 shall apply separately to the fuel or fuel blend concerned".*

5.1.9 Regarding the relevant time period within which Opportunity Cost is determined, paragraph 6 of the revised BMPCoP has been updated to make it clearer that the SRMC curve and COD is applicable to an ISP. The reference to the "operating day" has been removed from paragraph 36.a of the revised BMPCoP, and replaced with "the relevant time period concerned" thus allowing the participant flexibility to determine the appropriate ISP(s) for which the cost data submitted shall apply. Following this clarification, paragraph 36.a of the revised BMPCoP states: "*where there exists a recognised and generally accessible trading market in the relevant cost item, the OC of that item should reflect the prevailing market value or spot price of the cost item for the relevant time period concerned, which may be for immediate or future delivery or use as appropriate to the circumstances of the Licensee, having regard to costs the Licensee would incur in offering that cost item for sale, or acquiring that cost item, on a recognised and generally accessible trading market."*

5.1.10 Regarding change management provisions, paragraph 44 of the Draft BMPCoP has been elaborated significantly in the revised BMPCoP (see Section VI. Change Management).

6. NEXT STEPS

6.1.1 The RAs are presently reviewing responses to the consultation on electricity generation and supply licence conditions (consultation closed on the 4^{th} of July 2017), which inter-alia govern the compliance with the BMPCoP.[4]

6.1.2 The obligation to comply with this BMPCoP will come into force when both the relevant modifications have come into effect, and when part C of the T&SC comes into effect.

[4] On the 2nd June 2017, the Utility Regulator of Northern Ireland (UREGNI) published a “Statutory Consultation on Modifications to NI electricity generation and NI electricity supply Licences, necessitated to implement the Integrated Single Electricity Market I-SEM”. On the 2 June 2017, the CER also published an “Information Paper on proposed modifications to existing Generation and Supply licences, necessitated to implement the Integrated Single Electricity Market (I-SEM)” CER/17/111.