Single Electricity Market Committee

Gas Transportation Capacity Costs

Guidance to market participants on formulation of Commercial Offer Data, Provisional 'Good Cause' Determination & Outline of Next Steps

20 June 2013

SEM-13-039

CONTENTS

1 PURPOSE OF THIS DOCUMENT

1.1 In September 2012, the SEM Committee[1] consulted on the treatment of costs associated with gas transportation capacity ("**GTC**") in generators' commercial offer data ("**COD**", often referred to as 'bids'). The SEM Committee received a large number of responses which argued for various different interpretations and actions. On reviewing those responses the SEM Committee noted some divergences in the descriptions provided by various parties of the arrangements for allocation of, and trading in, GTC. It decided that it should conduct further work to ensure it had a clearer understanding of those arrangements and commissioned an expert report from Pöyry which it is publishing today alongside this document.

1.2 The SEM Committee intends to take steps shortly for the purpose of addressing, on an enduring basis, the treatment of GTC for bidding purposes and expects to communicate with market participants and others on those shortly.

1.3 Meantime, in light of calls from respondents to the consultation and from market participants more generally for clarity on the treatment of GTC costs, this document sets out the SEM Committee's provisional conclusions on the interpretation of generators' Cost-Reflectivity Licence Condition[2] and Bidding Code of Practice ('**BCOP**'). It also makes a provisional 'good cause determination' in relation to valuation principles within the BCOP and sets out the SEM Committee's intentions as regards next steps. In deciding to make that determination and in pursuing the proposed next steps, the Committee is mindful of the terms of the legal duties to which it is subject in each of the two jurisdictions across which the SEM operates. Details of those duties are set out in Annexes D & E.

1.4 The SEM Committee's conclusions and determination are provisional in two respects. First, they reflect its current understanding which will be reviewed in light of any comments received from market participants and others. Second, the process of developing the enduring policy position mentioned above may, in itself, require the SEM Committee to revisit its conclusions.

1.5 Finally, customer groups have highlighted the difficulties they faced in understanding the technical aspects of the September consultation. The SEM Committee hopes that, by issuing this document and taking the proposed next steps, it will assist those groups understand the technical framework and engage in the future with the SEM Committee on this issue.

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[1] The Commission for Energy Regulation ("**CER**") and the Northern Ireland Authority for Utility Regulation ("**NIAUR**") (together, the "**Regulatory Authorities**") have each established a committee (each known as an 'SEM Committee') which is entitled to take decisions as to the exercise of certain of the functions of the relevant Regulatory Authority. The expression 'SEM Committee' is used in this document to refer to both of those committees.

[2] Condition 15 of the generator licence (ROI) and Condition 17 of the generator licence (NI) ('**Condition 15/17**')

2 SUMMARY

2.1 The SEM Committee has consulted on the treatment of GTC costs within electricity generators' COD, has reviewed the various responses received and conducted further work to understand the GTC arrangements which generators may make. It has also received calls from market participants for clarity around the SEM Committee's interpretation of Condition 15/17 and the BCOP as regards GTC. The SEM Committee has therefore decided to provide this guidance which explains the following provisional conclusions, amongst others:

2.1.1 ROI generators should include GTC costs within their COD in circumstances where:

(i) They do not hold GTC in respect of a trading day at the point at which they submit their COD for that trading day and would acquire it were it needed ('Category A')

(ii) At the point at which they submit their COD for a trading day, they hold primary GTC and would sell it were it not needed ('Category B')

2.1.2 NI generators and ROI generators holding secondary GTC should not include GTC costs within their COD.

2.1.3 The BCOP, as currently drafted, does not provide a clear basis on which to value GTC.

2.2 For the reasons set out in this paper, the SEM Committee has also decided to make a provisional 'good cause' determination and to disapply the principles contained in paragraphs *8(i) to 8(iii) of the BCOP as regards GTC.*

2.3 *The* SEM Committee considers that where generators are able to include GTC costs within their COD, they should do so on the valuation bases set out in paragraphs 4.31 – 4.33 below.

1.4 The SEM Committee plans to consult further on enduring modifications to the BCOP. It intends to publish that consultation by 31 July. Meantime, any communications in respect of this provisional guidance and determination should be directed to:

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3 PREVIOUS CONSULTATION & GTC ARRANGEMENTS

PREVIOUS CONSULTATION

3.1 In response to developments in the market and suggestions that it should revisit the July 2007 statement of the Regulatory Authorities (the "**RA**s") on the treatment of GTC costs in generator bids[3], the Committee published a document on 27 September 2012 entitled, "*Single Electricity Market, Treatment of Gas Transportation Capacity Costs, Consultation Paper (SEM-12-089)*".

3.2 That consultation set out some factual background to current GTC arrangements and posed the questions noted in Annex A. By the end of November the SEM Committee had received over 30 different responses, a broad overview of which are also provided in Annex A. Copies of all non-confidential consultation responses are published with this paper].

GTC ARRANGEMENTS

3.3 In the following paragraphs, the Committee sets out its understanding of the arrangements under which generators (or shippers on their behalf) acquire and dispose of gas transportation capacity and the costs which they incur in that context[4].

3.4 Some electricity generating plants in both ROI and NI use gas as a source of fuel. A generator in that position[5] must also make arrangements to ensure that the relevant gas transporter[6] provides sufficient capacity on the gas transportation network to allow all the gas which the plant requires to be delivered (or shipped) to it. In ROI, generators are required to reserve the capacity which they will need separately from their purchase of the gas itself and

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[3] In the document entitled, *"The Bidding Code of Practice – A Response and Decision Paper"* (AIP-SEM-07-430) of 30 July 2007, the Regulatory Authorities stated, "*Without the ability to buy or sell gas transportation capacity for a trading day, as is the case currently in Ireland, payments for capacity on gas transportation networks are best understood as (semi) fixed costs. This means that, to meet licence conditions applying both in Northern Ireland and the Republic of Ireland, such costs should not be reflected in price bids submitted to the Market Operator. This means that the fixed costs of gas transportation would be recovered through either the CPM or the energy market through infra-marginal rents or both. The Regulatory Authorities are conscious that the trading of gas capacity is currently undergoing change, not least due to EC Directive compliance. As gas transportation capacity markets develop, costs which are currently incurred on an annual or monthly basis may become capable to being traded in such a way that allows them to be reflected in bids*".

[4] On 31 May 2013 the CER published a consultation paper entitled, "*Access Tariffs and Financing the Gas Transmission System (CER/13/122)*", which regarding access tariffs and financing of the ROI gas transmission system. Whilst the Committee recognises that certain of the proposals contained in that consultation paper may, if implemented, have an impact on the arrangements for the allocation and transfer of gas transmission capacity in ROI and, thus, on the behaviour of ROI generators as regards the bidding in of GTC costs, it has to concern itself with such arrangements as they currently stand.

[5] Strictly speaking, a shipper acting on behalf of the generator, although the SEM Committee understands that a number of electricity generators also hold gas shipper licences and 'self-ship'.

[6] 'Gaslink' in ROI, 'Bord Gais Networks' and 'Belfast Gas Transmission' in NI.

do so both with regard to 'entry' capacity (i.e. capacity to bring gas into the network, usually at the point of an interconnector) and 'exit' capacity (i.e. capacity at the particular point (the 'supply point') where the gas leaves the network). In NI, whilst generators are also required to reserve their required gas capacity, the reservation makes no distinction between entry and exit capacity.

3.5 GTC which is reserved in this way by a shipper directly with the relevant transporter is known as 'primary' capacity and there are various primary capacity products offered by transporters across a range of durations, ranging from annual, through monthly to daily products. The price at which primary capacity is sold to shippers is regulated by the relevant Regulatory Authority.

3.6 The minimum time increment for which it is possible to reserve primary capacity in either NI or ROI is one gas day, i.e. a period of 24 hours commencing 06.00 hours and ending 05.59 hours, which corresponds exactly to the SEM trading day.

3.7 In ROI, applications to reserve primary capacity for a single gas day can, in certain cases, be submitted on a 'within day' basis up to 03.00 hours on the gas day concerned[7]. By contrast, in NI, applications to reserve primary capacity for a single gas day have to be submitted no later than 12 business days prior to first day of the month in which the capacity is required[8].

3.8 In ROI it is possible for a shipper to transfer the primary capacity reserved by it in respect of a particular gas day to another shipper by submitting a request to the gas transporter. Such requests may be submitted on a 'within day' basis up to 01.45 hours on the gas day concerned (i.e. four hours and 15 minutes before the end of the gas day)[9].

3.9 Capacity in respect of a particular gas day (or any other period) which has been acquired by a shipper in ROI as a result of a transfer is known as 'secondary' capacity. The SEM Committee understands that it is not generally speaking permitted to transfer secondary capacity[10]. With one exception, the prices at which GTC is transferred are not transparent, but the SEM Committee understands that they are a usually a small fraction of the equivalent daily product. The exception is secondary exit capacity sales by Bord Gáis Energy from the Non-Daily Metered ("**NDM**") sector[11], for which a floor price is set by the CER.

[7] Under the code of operations maintained by Gaslink (part C, section 1.1.40), the "Daily Capacity Booking Window" remains open until 03.00 hours on the gas day in question in relation to certain requests for short term capacity.

[8] Section 1.4 of the transportation code maintained by Premier Transmission Limited on behalf of Belfast Gas Transmission. The code maintained by the other NI gas transporter, Bord Gais Networks, is in substantially identical terms.

[9] See for instance sections 3.1.6, 8.4.2 and 9.1.7 of part C of the Gaslink Code of Operations. It is also the case that a transferor may only request an exit capacity transfer under the code if such a transfer has previously been effected between the same parties in respect of the same category of exit capacity (and where relevant in respect of the same LDM Offtake(s)).

[10] See section 8.2.1 of part C of Gaslink Code of Operations, which relates to exit capacity. The SEM Committee understands that the transfer of secondary entry capacity is similarly prohibited. The Committee understands that, whilst it is possible for a transfer of primary capacity to be 'reversed' (in whole or in part), this is only observed to occur at the instance of the original seller (i.e. in whose favour the primary capacity was originally reserved), rather than at the instance of the original buyer.

[11] This would generally speaking encompass customers, such as domestic customers, consuming smaller volumes of gas, as compared to the daily metered sector which comprises larger customers (including Large Daily Metered ("**LDM**") customers, such as gas fired power stations).

3.10 The SEM Committee understands that a shipper in ROI who transfers primary capacity, including in respect of a single gas day, remains liable to the gas transporter for the capacity charges associated with that tranche of capacity as though the transfer had not taken place[12].

3.11 In NI it is not currently permitted to transfer primary capacity reserved for a particular gas day[13].

3.12 The SEM Committee also understands that both primary and secondary capacity may be 'interrupted' by the transporter for operational reasons but that, for the reasons outlined in the following paragraph, secondary capacity is generally considered by market participants to be more 'interruptible' than primary capacity.

3.13 In ROI, whilst the Gaslink Code does not distinguish between primary and secondary capacity as regards interruption, there is provision for a transfer to be cancelled, or called back (albeit with the consent of the transferee)[14]. The SEM Committee understands that the agreements struck between a transferor and a transferee may impose limits on the circumstances in which a transferee can refuse to provide that consent, which the SEM Committee recognise could have an impact on other commercial terms, including price, of the GTC being transferred.

[12] See for instance section 8.4.8 of part C of the Gaslink Code of Operations which provides that, "*Where a Within-Day Exit Capacity Transfer Request has been accepted, the Transferor Shipper shall remain liable for Capacity Charges in respect of the Primary Exit Capacity as if the Exit Capacity Transfer had not taken place. All other charges shall be payable by the Transferor Shipper or the Transferee Shipper (as the case may be) in accordance with this Code*". Similar provisions are contained in sections 2.4.3, 8.3.10 and 9.1.17. The SEM Committee understands that, whilst the transferor remains liable for the capacity charges and the financial security requirement associated with the supply point capacity that is transferred, all other charges (i.e., the operational use charges, such as the commodity charge, possible overrun charges, scheduling charges, shrinkage charges) are payable by the transferee shipper.

[13] This is prohibited, for instance, by section 1.12.2 and 1.12.3 of the PTL transportation code, which prohibits the transfer of daily products and requires transfers of parts of other products to be in relation to complete months.

[14] See for instance sections 3.2.1 and 3.3.1 of the Gaslink Code of Operations, which require both transporter and transferee consent for any 'call back' of secondary capacity from the transferor to the transferee. The commercial terms agreed between transferor and transferee may limit the circumstances in which such consent can be withheld.

4 PROVISIONAL CONCLUSIONS & GOOD CAUSE DETERMINATION

4.1 In addressing the question of inclusion of GTC costs in generator bids, the SEM Committee must consider, first, whether those costs fall within the concept of Short Run Marginal Cost (or SRMC) as defined by Condition 15/17 and, second, if that is the case what 'opportunity cost' (as defined in the BCOP) ("**Opportunity Cost**") should be attributed to such costs.

4.2 The Committee recognises that these are essentially interpretative, and not decision-making, tasks and so bears in mind the guidance provided by the Irish Supreme Court on the proper interpretation of both of these instruments in the proceedings brought in relation to the carbon revenue levy[15].

4.3 Nonetheless, there are two respects in which the Committee is entitled to exercise discretion in relation to the matter in hand. First, the BCOP confers discretion on the Committee to dis-apply the principles which the BCOP prescribes for arriving at an Opportunity Cost valuation where the Committee is satisfied that there is good cause for it to do so. Second, Condition 15/17 permits the Committee to modify the BCOP from time to time where it considers it appropriate to do so, subject to prior consultation.

SHORT RUN MARGINAL COST

4.4 The Committee considers the costs associated with GTC to be 'costs' for the purposes of paragraphs 1 to 3 of Condition 15/17. It also considers that paragraph 1 of Condition 15/17 operates such that, in formulating and submitting its COD, a generator is required to form an expectation as to the costs (including those associated with GTC) which its plant would, in fact, incur were it called upon to generate or not. That expectation should be formed on the basis of the information which is available to it at that time[16].

4.5 Paragraph 5 of Condition 15/17 allows for 'principles of good market behaviour' to be incorporated into the BCOP. These principles could be used to set certain standards, e.g. of reasonableness, which a generator must meet in forming its expectations as to costs.

4.6 The Committee considers that the expectations as to GTC costs which different generators may entertain when formulating their COD, will to a large extent depend upon the GTC trading strategies which they may adopt. It is not possible for the Committee to predict with accuracy the nature of any particular trading strategy, but it has identified three broad categories into which such strategies may fall. Clearly, an individual generator's trading strategy may exhibit elements of more than one of these categories, e.g., it might decide to hold some but not all of its GTC requirements at the point it submits its COD.

[15] *Viridian Power Limited & Huntstown Power Company Limited v The Commission for Energy Regulation & the Attorney General,* Supreme Court Case 285/2011

[16] This view is supported by the existence of the obligation in paragraph 9 for a generator to be able to provide its RA with a reasoned explanation and supporting evidence for its COD submission.

4.7 Category A (GTC in respect of relevant trading day not yet held): At the point of submitting its COD, a generator may have elected not to hold the GTC it would require were it called upon to generate on the trading day in question, but would acquire such GTC after submitting its COD were it so called upon.

4.8 The GTC costs of a category A generator would form part of its 'total costs' of generating under paragraph 3(a) of Condition 15/17 but would not form part of its 'total costs' of not generating under paragraph 3(b). The generator's SRMC should therefore properly include the costs of the required GTC. The value which the BCOP would attribute to those costs is considered below.

4.9 Gas-fired generators in ROI could, in principle, adopt a trading strategy which falls to some extent within category A as regards their ability, on a within-day basis, to book primary capacity from the transporter or to acquire it by way of transfer. However, in view of the minimum notice period required for reservations of primary daily capacity in Northern Ireland and the restriction on transfers of capacity in that jurisdiction, it would not be possible for an NI generator to adopt such a strategy.

4.10 Category B (GTC in respect of relevant trading day held but would be sold): At the point of submitting its COD, a generator may have elected to hold the primary GTC it would require were it called upon to generate on the trading day in question, but if it were not so called upon it would dispose of that tranche of GTC on a within-day basis.

4.11 The GTC costs of category B generator would form part of its 'total costs' of generating under paragraph 3(a). As the GTC would have been disposed of in the event of not running, its costs would not form part of the 'total costs' of generating under paragraph 3(b). The generator's SRMC would therefore include the costs of the required GTC.

4.12 As noted in paragraph [3.10] above, a shipper in ROI who transfers primary capacity, including in respect of a single gas day, remains liable to the gas transporter for the capacity charges associated with that tranche of capacity as though the transfer had not taken place. This might be taken to suggest that any such disposal is incomplete and that such a generator properly falls into category C (i.e. has no SRMC to bid in). However, the Committee suspects that any such residual liability is likely to be seen as 'neutralised' by the contractual liabilities assumed by the transferee.

4.13 Gas-fired generators in ROI holding primary (but not, in view of the transfer restriction, secondary)[17] capacity could, in principle, adopt a trading strategy which falls to some extent within category B. By contrast, in view of the restriction on transfers on primary capacity on a daily basis in Northern Ireland, it would not be possible for an NI generator to fall within category B.

[17] The restriction on transfers of secondary capacity is described in footnote [10] above, which also notes the potential for transfers of primary capacity to be 'reversed'. The Committee acknowledges that it may be possible for those arrangements for 'reversal' to evolve so as to permit an ROI generator which has purchased a secondary product to 'send back' that product to the seller but understands that such arrangements do not currently take place and so Category B appears to only apply to primary capacity.

4.14 Category C (GTC in respect of relevant trading day held but would not be sold): At the point of submitting its COD, a generator may hold the GTC it would require were it called upon to generate on the trading day in question, but if it were not so called upon it would not dispose of that tranche of GTC.

4.15 The GTC costs of a category C generator would form part of the 'total costs' of generating under paragraph 3(a) of Condition 15/17 and would also form part of the 'total costs' of not generating under paragraph 3(b). The generator's SRMC would not therefore properly include the costs of the required GTC.

4.16 ROI gas-fired generators holding primary GTC at point of submitting COD would not fall within category C, but (in view of the transfer restriction) those holding secondary GTC would fall within category C. However, given the inability to transfer daily GTC in Northern Ireland, all NI gas-fired generators would appear to fall within category C for bidding purposes. In this regard, the SEM Committee notes the various consultation responses which argued that GTC costs should be included in generators' COD in both ROI and NI. Given the different arrangements which exist in relation to GTC in both countries, the SEM Committee's provisional conclusion is that the current terms of Condition 15/17 and the BCOP mean that, in practice, NI generators will not be able to include GTC costs in their COD whilst, in some circumstances, ROI generators should.

VALUATION

4.17 The BCOP operates so as to attribute an Opportunity Cost value to the cost items included with SRMC in Condition 15/17. On the basis that secondary capacity can be called back; that, as the Committee understands it, the commercial terms on which secondary capacity is sold have generally reinforced such 'interruptibility' and given the differences emphasised in the consultation responses; the SEM Committee considers that primary and secondary capacity should be regarded as distinct products for valuation purposes. The Opportunity Cost valuation of GTC for the purpose of a generator's COD needs therefore to take account of whether the generator holds, or expects to acquire, primary or secondary capacity for the purposes of generation.

4.18 According to paragraph 7 of the BCOP, the Opportunity Cost of any cost-item comprises the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.

4.19 Paragraph 8 of the BCOP provides that, in calculating the value of the benefit foregone in employing a cost-item for the purposes of electricity generation, the following principles are to be applied, unless it can be demonstrated to the satisfaction of the relevant RA that there is good cause not to:

4.19.1 Where there exists a recognised and generally accessible trading market ("**RAGATM**") in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item (paragraph 8(i)).

4.19.2 Where no RAGATM exists in the relevant cost-item the Opportunity Cost of that item should reflect the costs which would be incurred by the relevant generator in replacing that cost-item (paragraph 8(ii).

4.20 The Committee doubts that the arrangements under which ROI primary or secondary capacity are acquired can properly be characterised as a RAGATM for the purposes of paragraph 8(i) of the BCOP[18]. In relation to primary products, reservation of capacity takes place in a regulated environment where only Gaslink can sell capacity and where it is not traded. In relation to secondary products, it is unclear to the Committee whether the arrangements for the purchase and sale between shippers are capable of constituting a RAGATM in view in particular of the following factors highlighted in the Poyry Report: (a) the low volume of trades relative to the (volumetric) size of the market; (b) the absence of reporting of prices of individual transactions either individually or on average over a given period; (c) the absence of a facilitated trading platform such as a bulletin board or an anonymous, cleared trading system; (d) the restrictions on resale of secondary capacity; and (e) the perceptions of many of the market participants who responded to the consultation.

4.21 Turning to replacement cost under paragraph 8(ii) of the BCOP, it does not appear to the Committee that it would be feasible, in view of the differing characteristics of ROI primary and secondary capacity products and the variety of trading strategies which ROI generators may choose to adopt, to identify one such cost which would be appropriate across all such generators in all circumstances.

4.22 Thus, to the extent that a generator's trading strategy falls within category A (i.e., it elects to not hold GTC in respect of relevant trading day at the point of submitting COD), the identification of a replacement value (for the purpose of identifying the benefit foregone were the unit in question called upon to run) would appear to depend on whether the generator would expect to make up any shortfall in GTC from within-day primary or secondary capacity.

4.23 To the extent the generator's trading strategy falls within category B (i.e., it holds primary GTC in respect of relevant trading day at the point of submitting COD, but is entitled to sell it if does not run), the result of applying the replacement cost principle in paragraph 8(ii) of the BCOP appears problematic. Paragraph 7 of the BCOP provides that the benefit foregone by the generator in such circumstances (i.e. the benefit achieved by selling unneeded primary capacity) is to be assessed, "*by reference to the most valuable realisable alternative use of* [the relevant] *cost-item*". In a category B scenario a generator is likely to face difficulties in realising any significant value by selling the primary capacity it holds in respect of a trading day into the secondary market given that that market is, as the Committee understands it, generally over-supplied and that such capacity can only be used on the trading day in question.

[18] This is despite the reference to both 'selling' and 'acquiring' items in paragraph 8(i)(a) of the BCOP, which the SEM Committee considers to recognise the possibility that a generator may either sell or buy within a RGATM and not to change the requirement for at least 'trades' to take place within a RAGTM.

4.24 Given that ROI gas-fired generators may in fact adopt trading strategies with features of both category A and category B and which employ differing combinations of primary and secondary GTC, the Committee is concerned that the ability of such generators to formulate COD which accurately reflects their SRMC (and the RAs' ability to monitor compliance with that requirement) may be compromised. As a corollary, the Committee anticipates that the scope and incentive for such generators to formulate misleading COD may be enhanced.

4.25 The Committee is also concerned that the replacement value for primary or secondary GTC suggested above in both the category A and category B scenarios may not adequately recognise that the scope to realise value from the sale of GTC within-day may diminish as the trading day progresses.

4.26 Further, in the absence of a RAGATM in GTC, the Committee is concerned that the identification of a replacement cost for such products risks being highly subjective and, thus, prone to manipulation or misstatement.

PROVISIONAL GOOD CAUSE DETERMINATION

4.27 Having reached provisional conclusions on the interpretation of Condition 15/17 and the BCOP, the SEM Committee must decide whether to take any action. In considering whether, and if so, what, action to take the SEM Committee is mindful of its various statutory objectives, duties and functions, which are set out in Annexes D and E. In particular, the SEM Committee has regard to the need to ensure transparent pricing in the SEM.

4.28 Therefore, in the Committee's view, the concerns noted above should be addressed by adopting an approach to valuing the Opportunity Cost of GTC other than that currently prescribed by the BCOP. The Committee is particularly mindful of (a) the extent of dubiety around whether either primary or secondary capacity arrangements can properly be characterised as RAGATM, (b) the lack of substitutability, for replacement purposes, between primary and secondary capacity and the complexity and uncertainty which that creates and (c) the problems associated with applying the replacement cost principle in paragraph 8(ii) of the BCOP. In that context, the Committee is satisfied in light of the matters discussed above that it has been demonstrated that there is good cause not to apply the principles laid down in paragraphs 8(i) to 8(iii) of the BCOP in arriving at an Opportunity Cost value for GTC costs.

4.29 The Committee also considers that, in view of the calls which it has received for clarity on the question of the bidding of GTC costs and the need to ensure transparent pricing in the SEM, it would be appropriate to provide guidance to the market on its views on the Opportunity Cost of GTC without further delay.

4.30 On this basis the Committee has concluded on a provisional basis that there is good cause why, in calculating the value of the benefit foregone in employing GTC for the purposes of electricity generation in the category A and B scenarios described above, the principles laid down in paragraphs 8(i) to 8(iii) of the BCOP should not apply. In the absence of those principles, the Committee considers that each relevant ROI generator should adopt the approach set out below in calculating the Opportunity Cost in relation to its GTC costs.

4.31 First, to the extent that the generator's trading strategy falls within the category A (GTC in respect of relevant trading day not yet held) scenario, the benefit foregone should correspond to the amount which the generator would expect to pay to purchase sufficient additional GTC on a within-day basis on the trading day in question.

4.32 That amount will depend on whether the generator is purchasing primary or secondary GTC. The Committee notes that a generator's choices in that respect will depend upon the commercial strategy which it pursues, the expected availability of each product and the degree of GTC 'interruptibility' which would be consistent with such strategy. Accounting for these considerations it is the Committee's expectation that in the majority of occasions a generator which falls into Category A would choose to purchase secondary within-day capacity.

4.33 Second, to the extent that a generator's trading strategy falls within the category B scenario (GTC in respect of relevant trading day held but may be sold), the benefit foregone should correspond to the amount which the generator would expect to realise by disposing of the unused GTC in the secondary within-day market on the trading day in question. In calculating such a benefit a generator should take account of the likelihood of being able sell such a product. The Committee notes that on many trading days there are no secondary trades and that, at the time of submitting COD, the expectation of being able to sell such capacity within day is likely to be low. Hence the Committee expects that the Opportunity Cost on the majority of trading days would be negligible.

4.34 The Committee will review these provisional conclusions in light of any comments received from market participants and others. It will also consider whether to take the further step of inserting a new valuation rule in relation to GTC costs into the BCOP for the purpose identified in paragraph 5(b) of Condition 15/17.

BIDDING BEHAVIOUR

4.35 The RAs (acting via the Committee) are entitled, for the purpose of paragraph 5(c) of Condition 15/17, to incorporate into the BCOP such principles of good market behaviour as, in the opinion of the relevant RA, should be observed by licensed generators in formulating their COD.

4.36 As discussed earlier, the ability of ROI generators with trading strategies falling within categories A or B to include GTC costs within their COD is subject to them first forming an expectation as to their ability to acquire GTC and/or dispose of unneeded GTC. In that context, the Committee considers that principles of good market behaviour could be established, using the powers mentioned above, to guide generators as to the circumstances in which they might or might not reasonably be in a position to form such expectations and, thus, to reflect those expectations in their COD submissions.

4.37 Such principles might, for instance, address the circumstances in which a generator might reasonably expect to locate a willing buyer (or seller) of capacity at different points in the trading day or more generally, e.g., in light of the availability of capacity products in the market.

4.38 In this context, for instance, the Committee notes Pöyry's suggestion, in section 6.2.1 of their report, that a generator which holds at gate closure some (but not all of) the GTC it ought to reflect in its COD an expectation that it will act to minimise any potential deviation between 'Schedule Production Cost' (as defined in Condition 15/17) and its SRMC[19]. Pöyry also point out, at section [5.3] of their report that they "*do not consider that it would be good market behaviour for generators to submit COD that would systematically lead them to incur* [… (a)] *overrun* [in ROI, unauthorised flow in NI] *charges* [… i.e. predicated] *on the possibility of removing gas from the ROI* [or NI] *system without capacity, thus incurring gas capacity overrun* [or unauthorised flow] *charges;* [… or (b)] *Uninstructed Imbalance charges (SEM)* [… i.e. predicated] *on the possibility of not complying with an electricity dispatch instruction and incur an Uninstructed Imbalance charge within the SEM*".

CAPACITY MECHANISM

4.39 Within the consultation paper, the Committee considered the possibility of recalculating the Best New Entrant ("**BNE**") element of the Capacity Payment Mechanism if the cost of short-term gas transportation capacity was required to be included within COD. The Committee does not currently propose to recalculate the BNE.

4.40 However, the Committee is mindful of its obligations to protect the interests of consumers. It will continue to monitor the bidding behaviour of market participants along with the effect of market outcomes on consumers.

[19] Pöyry also recommend that, "*for the purposes of the calculation of opportunity cost associated with gas capacity, generators should assign their gas entry capacity holding across their portfolio in a manner which would mimic behaviour in a fully competitive market*" for the reasons set out at paragraph 6.2.3 of their report.

5 NEXT STEPS

5.1 The Committee intends to take steps shortly for the purpose of addressing on an enduring basis the treatment of GTC for bidding purposes. It anticipates (subject to any comments received in response to this paper) that in addition to reviewing its provisional 'good cause' decision as to the disapplication of the valuation principles in paragraphs 8(i) and 8(ii) of the BCOP in relation to GTC costs, such steps may involve one or both of the following:

5.1.1 a proposal under paragraph 5 of Condition 15/17 to modify the BCOP so as to make provision, in respect of the calculation of the Opportunity Cost associated with GTC, for the treatment of the costs associated with that cost-item;

5.1.2 a proposal under that paragraph to modify the BCOP so as to include one or more principles of good market behaviour which should be observed in relation to the bidding of GTC costs.

5.2 Any discretionary decision concerning the treatment of GTC costs which the SEM Committee may take in due course will be taken in the light of, and in compliance with, the legal objectives, duties and functions to which it is subject in each of the two jurisdictions across which the SEM operates. Details of those duties are set out in Annexes D and E to this document.

5.3 The SEM Committee expects to publish a consultation paper setting out those next steps by the 31 July and to allow around 6 weeks for any further comments to be received. In the meantime, any communications concerning this document should be addressed in the first instance to:

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ANNEX A - SUMMARY CONSULTATION RESPONSES

This annex reproduces the questions posed in the September Consultation and provides a general summary of the responses which were received to them. Complete copies of all non-confidential consultation responses are published with this paper

1. *Has there been sufficient development in the trading of gas transportation capacity since the publication of the Bidding Code of Practice to allow the cost of such to be included within Commercial Offer Data? If so, why? Is this situation different between Northern Ireland and ROI?*

   A number of responses pointed to the existence of daily products in both ROI and NI and suggested that because of their availability, GTC costs should be included within generators' COD. The point was made that gas fired generators must be able to back their bids with a firm gas capacity product; a generator relying on secondary capacity cannot fully commit to being available for dispatch due to the interruptible nature of that capacity.

   Other responses highlighted the existence of the secondary market for GTC and suggested that this development was the basis for inclusion of GTC costs in generators' COD. Some other respondents highlighted the lack of liquidity, transparency and reliability in the secondary GTC market and also suggested that difficulties in valuing the opportunity cost of GTC under the BCOP meant that it could not be included within generators' COD.

   Nearly all respondents suggested that differences in generator COD between NI and ROI would be undesirable, with one respondent suggesting it could be contrary to EU law. Some responses suggested that if such differences existed, the SEM Committee should take action to remove them. Responses also noted the lack of secondary trading in NI.

   It was also suggested that the BCOP should be clarified to deal with this specific issue.

2. *Should the cost of gas transportation capacity be included in the Commercial Offer Data of units in Northern Ireland?*

   A number of responses answered 'yes' to this question on the basis that GTC can be bought for a single day in both NI and ROI and so long as a price component relates to a Trading Day, then it can be included in Commercial Offer Data, irrespective of when it was purchased. Some responses also suggested that the price to be included should be the regulated price and that if any decision is made to allow these costs, then both NI and ROI units should include them in order to provide equal treatment and prevent distortions in the market.

   Other responses suggested that because of the requirement to purchase short term gas capacity products 12 days in advance the opportunity cost of GTC in Northern Ireland could not currently be valued under the BCOP and so it was not possible for it to be included within generators' COD. Responses also suggested that, until the gas market for short term capacity products in NI had developed sufficiently to allow NI generators to include such costs in their

COD, there exist concerns in relation to the inclusion of short term gas capacity costs in one jurisdiction only.

3. *Should the cost of gas transportation capacity be included in the Commercial Offer Data of units in the Republic of Ireland? Is there any good cause why the principles within paragraphs 8(i) and 8(ii) of the Bidding Code of Practice should not be applied?*

   Some respondents saw no good cause not to apply to principles within paragraph 8(i) and 8(ii) of the BCOP.

   Responses generally highlighted the difference between primary and secondary capacity, illustrating why one cannot be seen as a replacement for the other. A number of responses suggested that the lack of price transparency in the secondary market meant that it could not be considered to be a 'recognised and generally accessible trading market'.

   In relation to primary capacity, it was suggested that the fact the BCOP referred to either buying or selling meant that the arrangements for acquiring primary capacity amounted to a 'recognised and generally accessible trading market'. A number of respondents pointed to replacement cost as the basis for valuing primary capacity. Such responses suggested that, as there are regulated short term gas capacity prices published in both NI and ROI, these prices were a fair, transparent source of pricing for SEM generators to use when costing their SRMC.

   Some respondents did not accept that there would be a perverse incentive to purchase primary daily capacity simply because of its ability to be included in bids. Some respondents suggested it was considered inappropriate for the RAs to put forward its subjective and speculative views as to what commercial decisions generators in the SEM might make with regard to gas capacity purchases.

   Other respondents stated that the there was a good cause not to apply the principles within paragraph 8 as the valuation was not clear and the requirement for a recognised and generally accessible trading market had not been met. It was also stated that the costs were already included within the cost of the BNE and hence the CPM; with some suggested that if the cost of capacity was included in commercial offers it could be argued that generators would recover transmission capacity costs twice.

4. *If the cost of gas transportation capacity is to be included in the Commercial Offer Data (of units in the Republic of Ireland) is there a recognised and generally accessible trading market in short term gas transportation capacity? Is this recognised and generally accessible trading market in secondary capacity or regulated daily capacity?*

   Responses generally noted that, as short term capacity products can only be sold by Gaslink, it was not believed that this constituted a recognised and generally accessible trading market.

In general, it was felt that there was no transparent and therefore generally accessible market in secondary capacity; and this market did not exhibit sufficient liquidity. It was suggested that the use of a non-firm capacity product was an inappropriate benchmark; once made, generators' commercial offers were firm. However, one respondent felt that there was a reasonably high level of secondary capacity trades and that this market was a recognised and generally accessible market.

5. *If the cost of gas transportation capacity is to be included in the Commercial Offer Data (of units in the Republic of Ireland) and there is no recognised and generally accessible trading market in short-term gas transportation capacity, what is the replacement cost?*

Some respondents pointed out that if a generator declared its availability to generate, then it should have firm capacity available for that period. One respondent did not see how anything other than the annual cost of firm capacity (for high load factor plant) and the cost of daily short term capacity (for low factor peaking plant) could be used to establish the replacement cost.

Another respondent stated that whether a RGATM existed or not, the relevant price for primary capacity was the daily regulated price of capacity. Secondary capacity could not be used as a substitute for primary capacity given that it was interruptible. It was suggested that using the price of secondary capacity within bids would make it difficult for the MMU to assess bids for compliance.

6. *If the cost of gas transportation capacity is included in the Commercial Offer Data (of units in the Republic of Ireland), should the price of BNE be recalculated?*

Some respondents were in favour of such a recalculation; arguing that generators should not receive a payment for gas capacity via the CPM and via the SMP. But there was concern that, if the CPM was recalculated, NI based generators could see a recalculation / reduction in capacity payments, but be unable to include these GTC costs in their COD.

Others stated that even if gas capacity costs were excluded from the BNE, the preferred technology would not change and there was no double compensation. It was also stated that because the BNE was distillate fired, no double payment would take place. Another respondent believed that the booking of annual capacity provided the most economical solution, in which case the cost was already included in the CPM.

It was suggested that the BNE was fixed for three years to provide a level of certainty to generators and to make an adjustment now would undermine confidence in the capacity mechanism.

7. *Which of the methods outlined in section 3 is the most appropriate for accounting for the cost of short term gas transportation capacity?*

A number of respondents stated that all gas generators should include the regulated market price for gas daily capacity in their COD.

One respondent deemed none of the methods suitable. A consistent and transparent approach that was reflective of the costs that generators would incur was called for.

8. *Are there any other methods for valuing gas transportation capacity which have not been included in Section 3?*

No alternative methods were put forward. It was stated that any method would be temporary since implementation of the EU 3rd Energy Package would bring about significant market changes. It was also suggested that the RAs should remain conscious of wider market developments at EU level and that the structures must be future proofed and in line with the target model.

One respondent said that if there was to be a fundamental shift in the pricing of short term gas capacity in the future, the inclusion of gas capacity costs in Commercial Offer Data might make sense.

Other comments

A number of large energy users expressed their views that they could not agree with any proposal that would result in an increase in electricity costs.

The point was made that where a portfolio of gas plant existed, the plant operator would purchase annual capacity based on the forecast requirement of the portfolio, and transfer between sites as needed. It was suggested that, on that basis and considering running levels in the last year, all CCGT plant in ROI would have purchased annual firm capacity. The response suggested that the remaining gas units were either “must run” or part of a larger portfolio and would have purchased all or a portion of their capacity as an annual firm product. The response also suggested that if a generator purchased annual firm capacity but is able to bid in daily firm prices, the result could be a windfall profit for the generator at the expense of the consumer.

Concerns were raised about the technical nature of the consultation. It was suggested that more should be done to ensure the consultation was fully understood by all those who have the potential to be affected and that modelling should be done to fully understand the cost implications for users.

ANNEX B - GENERIC TEXT OF GENERATION LICENCE CONDITION 15/17: COST REFLECTIVE BIDDING IN THE SINGLE ELECTRICITY MARKET[20]

1. *The Licensee shall ensure that the price components of all Commercial Offer Data submitted to the Single Market Operation Business under the Single Electricity Market Trading and Settlement Code, whether by the Licensee itself or by any person acting on its behalf in relation to a generation [unit/set] for which the Licensee is the licensed generator, are cost-reflective.*

2. *For the purposes of this Condition, the price component of any Commercial Offer Data shall be treated as cost-reflective only if, in relation to each relevant generation [unit/set], the Schedule Production Cost related to that generation [unit/set] in respect of the Trading Day to which the Commercial Offer Data submitted by or on behalf of the Licensee apply is equal to the Short Run Marginal Cost related to that generation [unit/set] in respect of that Trading Day.*

3. *For the purposes of paragraph 2, the Short Run Marginal Cost related to a generation [unit/set] in respect of a Trading Day is to be calculated as:*

   (a) the total costs that would be attributable to the ownership, operation and maintenance of that generation [unit/set] during that Trading Day if the generation [unit/set] were operating to generate electricity during that day;

   minus

   (b) the total costs that would be attributable to the ownership, operation and maintenance of that generation [unit/set] during that Trading Day if the generation [unit/set] was not operating to generate electricity during that day,

   the result of which calculation may be either a negative or a positive number

4. *For the purposes of paragraph 3, the costs attributable to the ownership, operation and maintenance of a generation [unit/set] shall be deemed, in respect of each relevant cost-item, to be the Opportunity Cost of that cost-item in relation to the relevant Trading Day.*

5. *The [Commission/Authority] may publish and, following consultation with [the holders of Generation Licences/generators] and such other persons as the [Commission/Authority] considers appropriate, from time to time by direction amend, a document to be known as the Bidding Code of Practice, which shall have the purposes of:*

[20] Text shown in square brackets appears in some licences but not all generation licences in the SEM

(a) defining the term Opportunity Cost;

(b) making provision, in respect of the calculation by the Licensee and other generators of the Opportunity Cost of specified cost-items, for the treatment of:

(i) the costs of fuel used by generators in the generation of electricity

(ii) the value to be attributed to credits issued under the Emissions Trading Scheme established by the European Commission;

(iii) variable operational and maintenance costs;

(iv) start-up and no load costs; and

(v) any other costs attributable to the generation of electricity; and

(c) setting out such other principles of good market behaviour as, in the opinion of the [Commission/Authority], should be observed by the Licensee and other generators in carrying out the activity to which paragraph 1 refers.

6. The Licensee shall, in carrying out the activity to which paragraph 1 refers, act so as to ensure its compliance with the requirements of the Bidding Code of Practice.

7. The [Commission/Authority] may issue directions to the Licensee for the purposes of securing that the Licensee, in carrying out the activity to which paragraph 1 refers, complies with [this licence/ the requirements of this Condition] and with the Bidding Code of Practice, and the Licensee shall comply with such directions.

8. The Licensee shall retain each set of Commercial Offer Data, and all of its supporting data relevant to the calculation of the price component of that Commercial Offer Data, for a period of at least four years commencing on the date on which the Commercial Offer Data is submitted to the Single Market Operation Business.

9. The Licensee shall, if required to do so by the [Commission/Authority], provide the [Commission/Authority] with:

(a) a reasoned explanation of its calculations in relation to any Commercial Offer Data; and

(b) supporting evidence sufficient to establish the consistency of that data with the obligations of the Licensee under this Condition.

10. In any case in which Commercial Offer Data are submitted to the Single Market Operation Business which are not consistent with the Licensee's obligation under paragraph 1 of this Condition, the Licensee shall immediately inform the

[Commission/Authority] and provide to the omission a statement of its reasons for the Commercial Offer Data submitted.

11. *[The Licensee shall by 1 June in each year submit to the Authority a certificate, signed by at least one director on behalf of the board of directors of the Licensee, to confirm that during the period of twelve months ending on the preceding 31 March:*

    (a) *It has acted independently in relation to all submissions of Commercial Offer Data that have been made, by it or on its behalf, under the Single Electricity Market Trading and Settlement Code; and*

    (b) *no such submissions made by it or on its behalf have been co-ordinated with any other submissions made by or on behalf of any other party to the Code.]*

12. *In this Condition:*

"Bidding Code of Practice"	*means the document of that title published by the [Commission/Authority] in accordance with paragraph 5, as it may be amended from time to time;*
"Commercial Offer Data"	*has the meaning given to it in the Single Electricity Market Trading and Settlement Code [as it may be amended from time to time];*
"Opportunity Cost"	*shall have the meaning set out in, and the value calculated in accordance with, the terms of the Bidding Code of Practice;*
"Schedule Production Cost"	*has the meaning given to it in the Single Electricity Market Trading and Settlement Code [as may be amended from time to time];*
"Short Run Marginal Cost"	*means certain costs attributable to the ownership, operation and maintenance of a generation [unit/set], as calculated in accordance with paragraph 3 of this Condition;*
"Single Market Operation Business"	*has the meaning given to it in the [licence granted pursuant to section 14(1)(j) of the Act / market operator licence for Northern*

Ireland]; and

"Trading Day"	*has the meaning given to it in the Single Electricity Market Trading and Settlement Code [as it may be amended from time to time]."*

ANNEX C - EXTRACT BIDDING CODE OF PRACTICE (PARAGRAPHS 6-9)

DEFINITION OF OPPORTUNITY COST

General Principles

6. *When calculating the Short Run Marginal Cost of a generation set or unit in respect of a Trading Day, constituent cost-items are to be valued at their Opportunity Cost, and so that a reasoned explanation of the calculation of that Opportunity Cost is capable of being given to the Authority or the Commission (as appropriate) on request.*

7. *The Opportunity Cost of any cost-item shall comprise the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.*

8. *In calculating the value of the benefit foregone in employing a cost-item for the purposes of electricity generation, the following principles shall, unless it can be demonstrated to the satisfaction of the Authority or the Commission (as appropriate) that there is good cause not to, be applied:*

   (i) *where there exists a recognised and generally accessible trading market in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item, which may be for immediate or future delivery or use as appropriate to the circumstances of the relevant generator, having regard to:*

(a) costs the relevant generator would incur in offering that cost-item for sale, or acquiring that cost-item, on a recognised and generally accessible trading market;

(b) reasonable provision for the variability of the prevailing price of a cost-item on a recognised and generally accessible trading market;

(ii) where no recognised and generally accessible trading market exists in the relevant cost-item the Opportunity Cost of that item should reflect the costs which would be incurred by the relevant generator in replacing that cost-item; and

(iii) reasonable provision for increased risks to plant and equipment as a result of the operation of a generation set or unit may be included.

1. *Subject to paragraph 12, all Commercial Offer Data submitted in respect of a generation set or unit are to reflect the costs relating to that generation set or unit when considered on a stand-alone basis."*

ANNEX D - PRINCIPLE OBJECTIVE AND FUNCTIONS OF THE COMMISSION FOR ENERGY REGULATION

Energy Regulation Act 1999 - Sections 9BC & 9BD

Principal objective and functions of Minister, the Commission and SEM Committee in carrying out their functions in relation to the Single Electricity Market

9BC.—(1) The principal objective of—

(*a*) the Minister in carrying out his or her electricity functions in relation to matters which the Minister considers materially affect, or are likely materially to affect, the Single Electricity Market,

(*b*) the Commission in giving effect to any decision of the SEM Committee, and

(*c*) the SEM Committee in carrying out its functions under section 8A(4), is to protect the interests of consumers of electricity in the State and Northern Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the Single Electricity Market.

(2) The Minister, the Commission and the SEM Committee shall carry out their respective functions referred to in subsection (1) in the manner which each considers is best calculated to further the principal objective, having regard to—

(*a*) the need to secure that all reasonable demands for electricity in the State and Northern Ireland are met,

(*b*) the need to secure that authorised persons are able to finance the activities which are the subject of conditions or obligations imposed by or under this Act or the Internal Market Regulations or any corresponding provision of the law of Northern Ireland,

(*c*) the need to secure that the functions of the Minister, the Commission, the Authority, and the Department in relation to the Single Electricity Market are exercised in a coordinated manner,

(*d*) the need to ensure transparent pricing in the Single Electricity Market, and

(*e*) the need to avoid unfair discrimination between consumers in the State and consumers in Northern Ireland.

(3) The Minister, the Commission and the SEM Committee may, in carrying out any of the functions mentioned in subsection (1), have regard to the interests of consumers in the State and Northern Ireland in relation to gas.

(4) Subject to subsection (2), the Minister, the Commission and the SEM Committee shall carry out the functions mentioned in subsection (1) in the manner which each of them consider is best calculated—

(*a*) to promote efficiency and economy on the part of authorised persons,

(*b*) to secure a diverse, viable and environmentally sustainable long-term energy supply in the State and Northern Ireland,

(*c*) to promote research into, and the development and use of—

(i) new techniques by or on behalf of authorised persons, and

(ii) methods of increasing efficiency in the use and generation of electricity.

(5) Subject to subsection (2), in carrying out any of the functions mentioned in subsection (1) the Minister, the Commission and the SEM Committee shall have regard to—

(*a*) the effect on the environment in the State and Northern Ireland of the activities of authorised persons, and

(*b*) the need, where appropriate, to promote the use of energy from renewable energy sources.

(6) In carrying out any of the functions mentioned in subsection (1) the Minister, the Commission and the SEM Committee shall not discriminate unfairly as regards terms and conditions—

(*a*) between authorised persons, or

(*b*) between persons who are applying to become authorised persons.

(7) In this section—

'authorised person' means the holder of a licence or exemption under a provision of this Act relating to electricity or under any corresponding provision of the law of Northern Ireland;

'electricity functions' means—

(*a*) functions under this Act, and

(*b*) functions under the Internal Market Regulations, relating to electricity;

‘environmentally sustainable’ includes the need to guard against climate change;

‘renewable energy sources’ has the same meaning as in Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC1.

Performance of functions relating to Single Electricity Market

9BD.—The Minister, the Commission and the SEM Committee shall have regard to the objective that the performance of any of their respective functions in relation to the Single Electricity Market should, to the extent that the person exercising the function believes is practical in the circumstances, be transparent, accountable, proportionate, consistent and targeted only at cases where action is needed.

ANNEX E - PRINCIPLE OBJECTIVE AND FUNCTIONS OF THE UTILITY REGULATOR SEM COMMITTEE

The Electricity (Single Wholesale Market (Northern Ireland) Order 2007
Articles 9 & 10

Principal objective and duties of Department, the Authority and SEM Committee in relation to SEM

9.

(1) The principal objective of—

(a) the Department in carrying out its electricity functions in relation to matters which it considers materially affect, or are likely materially to affect, the SEM;

(b) the Authority in carrying out its functions under Article 3 (b) the Authority in giving effect to any decision of the SEM Committee;

(c) the SEM Committee in carrying out its functions under Article 6(2),

is to protect the interests of consumers of electricity in Northern Ireland and Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the SEM.

(2) The Department, the Authority and the SEM Committee shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard to—

(a) the need to secure that all reasonable demands for electricity in Northern Ireland and Ireland are met; and

(b) the need to secure that authorised persons are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or the Energy Order or any corresponding provision of the law of Ireland; and

(c) the need to secure that the functions of the Department, the Authority, the Irish Minister and CER in relation to the SEM are exercised in a co-ordinated manner,

(d) the need to ensure transparent pricing in the SEM;

(e) the need to avoid unfair discrimination between consumers in Northern Ireland and consumers in Ireland.

(3) The Department, the Authority and the SEM Committee may, in carrying out any of the functions mentioned in paragraph (1), have regard to the interests of consumers in Northern Ireland and Ireland in relation to gas.

(4) Subject to paragraph (2), the Department, the Authority and the SEM Committee shall carry out the functions mentioned in paragraph (1) in the manner which it considers is best calculated—

(a) to promote efficiency and economy on the part of authorised persons;

(b) to secure a diverse, viable and environmentally sustainable long-term energy supply in Northern Ireland and Ireland; and

(c) to promote research into, and the development and use of—

(i) new techniques by or on behalf of authorised persons;
(ii) methods of increasing efficiency in the use and generation of electricity.

(5) Subject to paragraph (2), in carrying out any of the functions mentioned in paragraph (1) the Department, the Authority and the SEM Committee shall have regard to—

(a) the effect on the environment in Northern Ireland and Ireland of the activities of authorised persons, and

(b) the need, where appropriate, to promote the use of energy from renewable energy sources.

(6) In carrying out any of the functions mentioned in paragraph (1) the Department, the Authority and the SEM Committee shall not discriminate unfairly—

(a) between authorised persons; or

(b) between persons who are applying to become authorised persons.

(7) In carrying out any of the functions mentioned in paragraph (1) in accordance with the preceding provisions of this Article, the Department, the Authority and the SEM Committee shall have regard to—

(a) the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed;

(b) any other principles appearing to it to represent the best regulatory practice.

(8) In this Article—

"authorised person" means the holder of a licence or exemption granted under Part II of the Electricity Order or any corresponding provision of the law of Ireland;

"electricity functions" means —

(a) functions under Part II of the Electricity Order;
(b) functions under the Energy Order relating to electricity;
(c) functions under Part IV of the Electricity Order 1992 (Amendment) Regulations (Northern Ireland) 2005 (SR 2005/ 335); and
(d) functions under this Order;

"environmental sustainability" includes the need to guard against climate change; and

"renewable energy sources" has the same meaning as in the Directive.

(9) In relation to any time after the coming into operation of Article 3 but before the establishment of the SEM Committee, this Article has effect as if for paragraph (1)(b) there were substituted—

" (b) the Authority in carrying out its functions under Article 3;"

Exemptions from the general duties

10

(1) Article 9 does not apply in relation to the functions of the Department under

(a) Article 39, 40, 58, 59 or 60 of the Electricity Order; or
(b) Article 61 of the Energy Order

(2) Article 9 does not apply in relation to anything done by the SEM Committee in talking a decision as to the exercise of any function of the Authority-

(a) which relates to the determination of disputes;

(b) under Article 46(3) of the Electricity Order [NOTE: *Functions with respect to competition*]; or

(c) under Article 8 of the Energy Order [NOTE: *Powers of Authority in relation to external matters*];

or to anything done by the Authority in giving effect to that decision.

(3) The SEM Committee may nevertheless, when taking a decision as to the exercise of any function of the Authority under Article 46(3) of the Electricity Order, have regard to any matter in respect of which a duty is imposed by Article 9 if it is a matter to which the Office of Fair Trading could have regard when exercising that function.

(4) The duties imposed by Article 9 do not affect the obligation of the Authority or the Department to perform or comply with any other duty or requirement (whether arising under this Order or another statutory provision, by virtue of any Community obligation or otherwise).