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Consultation Paper SEM-16-059: Offers in the I-SEM Balancing Market

A Report for Viridian

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Project Team

Graham Shuttleworth
George Anstey

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

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1. Overview and Conclusions

This report sets out our comments on I-SEM Consultation Paper SEM-16-059, Offers in the I-SEM Balancing Market, dated 7 October 2016 (the "Consultation Paper"). The Consultation Paper sets out the SEM Committee's proposals for a new bidding code of practice for the I-SEM.

1.1. Appraisal Criteria

In compiling our views on the Consultation Paper, we have tried to apply the same appraisal criteria as the SEM Committee set out in earlier stages of the workstream. For instance, section 8 of the initial Consultation Paper (SEM-15-094) appraises possible measures by assessing the extent which they are: effective (in achieving their aims); targeted (on specific hindrances to competition and efficiency); and also flexible, practical, and transparent.

Like the SEM Committee, we are conscious of the trade-offs between these criteria. e.g.: between flexibility and transparency (if flexibility leads to the rules being unclear); between flexibility and effectiveness (if rules must be stable to be effective); between effectiveness and practicality (if the optimal rule cannot be applied with the information available); etc. We take it for granted that the SEM Committee wishes to support competition and efficiency, both in the pursuit of its statutory duties and as a component of ensuring that controls are suitably targeted.

1.2. Economic Constraints

The proposed bid limits on generators in I-SEM form part of wider market power controls on generators, including proposed limits on offers in the Capacity Remuneration Mechanism (CRM). The proposal to introduce auctions for DS3 ancillary services may also include formal offer controls. To promote economic efficiency, the bid limits for each mechanism must observe two economic constraints:

- Firstly, they must allow generators to signal and to recoup the cost of providing the relevant services. In particular, economic efficiency will be reduced and competition distorted if bid limits do not allow generators to bid the full Short Run Marginal Cost (SRMC) of their generation. If bid limits impose prices below the SRMC of any generator required for system stability, that generator will have an incentive to withdraw its capacity from the market and the demand side will not receive the efficient economic signal for deciding its consumption.

- Secondly, taking together all the bid limits placed on each of the revenue streams available to generators, they must allow total generator revenues to rise above SRMC in each mechanism at each moment in time, to the point where generators can at least recover the Long Run Marginal Cost (LRMC) of generation. If prices cannot rise above SRMC in each mechanism, generators will be unable to recover their fixed costs and market participants will have no incentive to invest in building new capacity or maintaining existing capacity.

These economic constraints limit the ability of the regulatory authorities (RAs) to restrict any individual offer price or to deny the recovery of any individual cost item.

The regulation of offer prices, as defined in the current Bidding Code of Practice (BCOP) and in the current Consultation Paper, may take any of the following formats:

a) guiding principles that market participants must apply in all their bidding;
b) lists of specific cost items which may be included in bids and the approach to quantifying those items;
c) formulaic prescriptions of maximum and minimum prices that may be offered.

The SEM Committee's Option 1 lists cost items and how to calculate them (i.e. format (b)) and Option 2 describes the SEM Committee's approach to defining a formula (i.e. format (c)). However, guiding principles (format (a)) are missing from the current set of proposals. This omission is a major flaw in these proposals, because the I-SEM would in any case need a set of principles to clarify definitions, and also because setting principles offers advantages over prescribing formulae. Indeed, relying on a set of guiding principles like those in the current BCOP offers a better alternative to any set of detailed rules. Compared with detailed rules referring to specific costs, guiding principles based on sound economics are: (1) are less likely to become outdated; (2) likely to remain more stable over the long run; and (3) therefore more conducive to efficient decision-making and competitive behaviour by market participants. Defining offer price limits as guiding principles has worked well under the current BCOP (as acknowledged in the Consultation Paper), as they provide flexibility in changing situations. They also minimise the risk of fixed rules denying cost recovery, with all the associated adverse consequences for incentives and efficiency.

We conclude that the SEM Committee would be best advised to amend the BCOP so that it fits the I-SEM, rather than trying to draft a new set of prescriptive rules intended to define precisely what costs may be included in offer prices. Should the SEM Committee decide (unwisely in our view) to set prescriptive rules, we conclude they should also set down the economic definitions of basic concepts and the principles needed to guide future revisions to the rules, which changing circumstances are bound to make necessary. Otherwise the system will lack any long term stability, transparency or credibility, and will hinder efficiency and competition.

To enhance the credibility of these basic concepts and guiding principles, they need to be placed in a more stable document than an industry code that the RAs can change at will. We conclude therefore that, like the economic definitions of SRMC and OC at present, these basic concepts and guiding principles belong in the generation licence, or in any other document governed by an amendment procedure equivalent to that of a generation licence.

1.3. Main Conclusions by Chapter

We have structured this report to correspond with the substantive chapters (Chs 2-5) of the Consultation Paper. Our conclusions are as follows:

- Chapter 2 of the Consultation Paper proposes the introduction of bidding controls, in the first instance only on non-energy actions in the balancing market, with the possibility of extending them in future to energy actions. The proposals create regulatory risk for market participants over both the distinction between energy and non-energy actions and over the prospect of more intrusive regulation in the future.

  - Regulatory risk stems both from the regulation itself and from the process governing changes to regulation. In the short term, the design of the algorithm determining energy and non-energy actions is subjective and lacks transparency. In the longer term, there is no defined process for overseeing changes to the algorithm by the TSO, and no basis for market participants to know what behaviour might provoke an extension of the controls. This regulatory risk will discourage some competitive behaviour by market participants and therefore threatens to raise prices to consumers.
  - In order to diminish regulatory risk and to reduce costs to consumers, the SEM Committee will need to support any bidding controls with clear guiding principles that are robust to changing circumstances and founded in economics. Prescriptive rules that become obsolete or that do not reflect economic fundamentals will come under pressure over time and expose market participants to additional regulatory risk.
- Chapter 3 of the Consultation Paper lists objections to the current form of bidding controls derived from the experience of applying them. Our analysis of these objections shows that they arise from a purely partial application of appraisal criteria and a misunderstanding of the cause and nature of disputes over the interpretation or design of regulatory rules.
  - Such disputes are inevitable, due to the "incompleteness" of any rules, and need not be regarded as a failure, but rather as the process for providing greater clarity. As a result, Chapter 3 of the Consultation Paper gives the SEM Committee no procedural or intellectual basis for the proposals that follow in later chapters.
  - The opportunity to dispute the market rules provides an important protection against regulatory failure: if the SEM Committee were to set offer price limits below marginal costs, market participants would exit the market and security of supply would be threatened. The prospect of contesting offer price limits lessens the chance of such outcomes and mitigates regulatory risk, as long market participants can refer to a stable and clearly defined basis for such limits.
  - Setting out such guiding principles in licence conditions (or another document with an equivalent change management process) provides the necessary clarity and stability, and therefore protects consumers as well as market participants from regulatory failure.
- Chapter 4 of the Consultation Paper sets out the SEM Committee's proposed high-level options for imposing offer limits. It contains a number of flaws.
  - The SEM Committee describes Option 1 as a principles-based approach similar in outline to the current BCOP. In practice, however, Option 1 consists of a prescriptive list of costs that may be included in offer prices, along with rules for defining those costs. These rules are so narrowly defined that they offer no guidance on how to incorporate new costs when circumstances change over time. Even in the short term, the proposals exclude for no good reason several potentially important categories of cost, such as costs which may be jointly incurred over multiple settlement periods and the opportunity costs of additional risks.
  - The SEM Committee contradicts the conclusions from its 2008 inquiry into bidding practices. At the time, the SEM Committee concluded that it "does not consider that a generator should be required under its Licence to incur significant avoidable costs without the prospect of being able to recover them"; "that all the avoidable costs

outlined above – the additional O&M expenditure, the additional equipment costs, the increased risk of failure to plant and equipment as a result of the plant's running regime and the concomitant loss of revenue from capacity payments and infra-marginal rents from SMP – are allowable costs"; and that "to do otherwise could threaten the development of efficient new entry and effective competition, given that it may dissuade generators from entering the market if they perceive that they may incur irrecoverable forward-looking costs when doing so."[1]

- Option 2 consists of simplified rules which impose offer limits on generators according to calculations carried out by the SEM Committee on behalf of market participants. However, as the SEM Committee implicitly acknowledges by providing for exceptions, that it will need to ensure any offer limits remain in line with generators' SRMC. That need will not only require frequent and rapid changes to the rules, but will also require the SEM Committee to set out and apply clear guiding principles for managing adjustments to the simplified rules; only then will the regime minimise regulatory risk and incentivise efficient, competitive behaviour. Option 1 and Option 2 therefore both require the development of the same guiding principles to allow their adaptation over time. In the case of Option 2, the need to adapt rules over time applies not only to the definition of new cost items but also to the calculation itself. Option 2 does not in effect represent a different approach from Option 1, only a less complete one.
- The similarities between the Options, and the gaps in each of them, are not brought to light in the evaluation set out in the Consultation Paper, because it has not been properly conducted. The evaluation of the Options does not apply the criteria used in other I-SEM papers, or any similar set, but only identifies vaguely articulated "advantages" and "disadvantages" relative to some nebulous (and possibly shifting) alternative. The evaluation is therefore partial and unsound as a basis for making any decision.

The remaining chapters of this report set out the analysis behind these conclusions, in the order corresponding to the substantive chapters (Chs 2-5) of the Consultation Paper.

1.4. Response to Consultation Questions and Summary of Recommended Actions

The Consultation Paper poses two direct questions to respondents. This document implicitly gives our response to these questions. We set out brief, specific answers to the consultation questions below:

Consultation question 1: *Do you agree with the proposed approaches to offer controls in the Balancing Market for I-SEM outlined above? If a respondent does not agree with any part of a proposed approach, please specify why and provide detailed alternative.*

We do not agree with the proposed approaches to offer controls in the Balancing Market for I-SEM. The SEM Committee argues that the BCOP has been effective over the course of the

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[1] SEM Committee (2008), *Complaints on Bidding Practices in the Single Electricity Market: SEM Committee Inquiry,* Final Report, SEM-08-069, 12 June 2008, pages 31-32.

SEM. The SEM Committee then proposes to replace the BCOP with a more detailed and less flexible set of rules, largely because it believes that lack of clarity in the existing BCOP has led to disputes. The SEM Committee has not explained how steps to reduce disputes with market participants would better meet its evaluation criteria, including competition and efficiency. However, in any case, more detailed bidding controls will not improve clarity or reduce the scope for disputes. Even if detailed prescriptive rules are correctly formulated to begin with (which we doubt), they will soon become outdated, preventing generators from bidding efficiently and prompting numerous disputes. A better alternative would be to amend the current framework set out in the generation licence and BCOP, which is acknowledged to have been effective, to fit the timescale of the new Balancing Market (see below).

Consultation question 2: *Which of the options identified within this Consultation Paper would be most appropriate for the introduction of offer controls under I-SEM?11 If a respondent does not agree with any of options identified, please specify why and provide detailed alternative. If a respondent has a preferred option, please indicate whether any aspect of the preferred option should be amended?*

Neither of the SEM Committee's proposed Options 1 or 2 is suitable for implementation under I-SEM. Both Options 1 and 2 are incomplete, inflexible, likely distort competition and economic efficiency, and bound to result in the errors and disputes that the SEM Committee is seeking to avoid. Instead, the SEM Committee should replace – or at the very least augment – the proposed rules with a stable set of guiding principles. In practice, the SEM Committee could most easily achieve this with a minor amendment to the existing BCOP and generation licences by replacing references to the "Trading Day" with "Balancing Market Action".[2]

Our analysis has a number of implications for the SEM Committee's approach to offer controls. We provide a list of these implications, in the form of detailed recommendations inspired by Consultation Questions 1 and 2, in Table 1.1 below.

2 A Balancing Market Action is the change in output resulting from a single instruction from the TSO in the Balancing Market.

Table 1.1
Recommendations for Revisions to SEM Committee Proposals

#	Recommendation	Ref
	General Recommendations	
1	SEM Committee should amend the generation licence and the BCOP by clarifying that SRMC should be estimated over a Balancing Market Action rather than Trading Day.	1.2
2	SEM Committee should rely on high-level principles rather than prescriptive rules. Any such guiding principles must be robust to changing circumstances and provide certainty to market participants that they will be able to bid their SRMC in the market. Adopting Option 1 or 2 would require separate drafting of guiding principles to ensure that the rules allowed generators to bid and to recoup their SRMC.	1.2, 2.3, 2.4
3	Any future extension of bidding controls to energy actions should either be limited to tightly-defined circumstances defined in advance, or explicitly follow the criteria of general competition policy.	2.3
4	If SEM Committee imposes more tightly-defined rules than the existing BCOP, it should only do so where the calculation of the individual cost items is clear. Any set of tightly-defined rules to calculate SRMC will necessarily be incomplete, and so should provide for “any other costs” that fall within SRMC.	3.2.2
5	If SEM Committee opts to rely on (overly-)prescriptive rules, it should set out economic definitions of basic concepts and clear guiding principles for updating the rules as circumstances change	1.2
6	SEM Committee should place guiding principles and economic definitions in generators' licences, or equivalent documents that provide the required degree of stability and certainty. Any prescriptive rules or calculations, intended to provide clarity but which may become obsolete, may be placed within industry codes or similar documents, so that they can be amended quickly in the light of stable principles. (Such rules should not prevent rapid adjustment when conditions change.) SEM Committee should explain any decision to adopt a different legal structure from the current one, by its usual appraisal criteria.	1.2, 3.1
	If the SEM Committee chooses Option 1:	
7	The rules should permit generators to bid costs incurred over multiple settlement periods ("joint costs") to reflect the incremental costs of balancing market actions.	2.2.5, 4.2.3
8	The rules should allow generators to bid their full SRMC valued at opportunity cost. These costs include variable maintenance costs, costs of risk and foregone revenues (as stated by SEM Committee under the current regime and in other I-SEM documents).	4.2.2, 4.2.3, 4.2.4, 4.2.5
	If the SEM Committee chooses Option 2:	
9	Offer limits for each generator must be no lower than the SRMC of that generator, valued at opportunity cost.	4.3.1, 4.3.6
10	If new conditions arise, offer limits must be amended, guided by clearly-defined (economic) principles. Offer limits for each generator must be no lower than the SRMC of that generator valued at opportunity cost (including variable maintenance costs, costs of risk and foregone revenues – see Recommendation 8).	4.3.1, 4.3.3, 4.3.5, 4.3.6
11	Principles for revising offer limits should be stated in generators' licences (or equivalent documents), rather than in an industry code governed by weak change management procedures.	4.3.1, 4.3.6

2. Introduction

2.1. The Proposals Significantly Change the Form of Controls

The basis for the current proposals is set out in section 2.1 of the Consultation Paper. The workstream on Market Power Mitigation (MPM) in energy markets has previously produced a Discussion Paper (SEM-15-031), a Consultation Paper (SEM-15-094) and a Decision Paper (SEM-16-024). The Decision Paper stated that MPM measures for energy markets would be limited to the Balancing Market, and summarises the proposals as follows:

- "energy actions[fn] in the Balancing Market will have no explicit ex-ante offer controls, but the SEM Committee will, by developing a framework, implement ex-ante offer controls either on individual participants or across the wider market if observed behaviour is deemed to warrant this; and
- non-energy[fn] actions of units operating in the Balancing Market will be settled based on 3-part offers, which will have an explicit ex-ante offer control applied to them."[3]

The footnotes ("fn") in these bullets refer to definitions of energy and non-energy actions in the I-SEM Energy Trading Arrangements Detailed Design Consultation Paper (SEM-15-026).

The proposals themselves come in two variants:

- Option 1 is named "Offer Principles", but is actually a definitive list of the costs that generators may include in their offer prices (and a prohibition on including any other costs);
- Option 2 would allow the RAs to set "Offer Limits", i.e. maximum offer prices, based on principles that are not defined in the Consultation Paper (and would have to be "fully consulted upon to ensure transparency").

In both cases, all text defining the controls would be set out in a code. Whereas the current Bidding Code of Practice is supported by guiding principles and economic definitions (SRMC, OC) set out in the generation licence,[4] under the current proposals generation licences would only contain a short-form obligation to comply with the new code.

2.2. The Reasons for Abandoning the Current Controls Are Unconvincing

On page 6 of the Consultation Paper, the RAs set out their reasons for wanting to abandon the current BCOP in favour of a different approach. These reasons are unconvincing, and in some cases appear to conflict with the RAs' statutory duties.

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3 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 3.

4 In the Generic Generation Licence published by the Commission for Energy Regulation, the relevant provisions are found in Section C, Condition 15, subsections 2 to 4. The same wording is used in generation licences issued by the Utility Regulator for Northern Ireland.

2.2.1. Reasons given in the Consultation Paper

The SEM Committee has repeatedly acknowledged the effectiveness of the current BCOP in managing market power in the SEM. The Decision Paper recorded that "A majority of respondents agreed with the SEM Committee's view that the SEM market power mitigation measures were largely effective".[5] It also recorded the SEM Committee's response to comments on the scope of the current BCOP, noting "The SEM Committee is of the view that the introduction of I-SEM provides an opportunity to make any bidding controls more targeted", but did not note any requirement to change the format of the controls. Indeed, in relation to the Balancing Market, the Decision Paper states explicitly that "The form of the bidding control will be considered in the coming months by the SEM Committee and will be ultimately be [sic] proposed in a licence condition."[6]

The Consultation Paper continues to acknowledge the effectiveness of the current BCOP; section 3.3 opens with "Notwithstanding the effectiveness of the existing BCOP,…" However, although nothing within the Decision Paper foreshadows it, the SEM Committee takes issue in the Consultation Paper with the process of implementing the current BCOP, and now proposes to locate the whole of the bidding code in a separate document, outside the generation licences. The principal reason given in the Consultation Paper for changing the form of the control is:

> "existing issues around the current bidding control arrangements, such as transparency of what costs are appropriate and what are not, would continue (e.g. the current arrangements do not explicitly state how some cost items should be applied). Experience with legal, and other challenges, to the existing arrangements would also persist."

As we discuss further below, the Consultation Paper does not provide any evidence that the proposed Options 1 and 2 would handle these "existing issues" any better than the current bidding control arrangements. Nevertheless, the Consultation Paper suggests two remedies to these "existing issues" under the BCOP:

- First, the proposals would remove from generation licences the guiding principles and economic definitions that currently underpin offer price controls, and would place all the rules within a revised code, allegedly to provide "greater clarity, flexibility and detail to market participants".

- Second, the RAs identify a problem because "the BCoP only provides minimal detail on Start-up and No Load costs; VOM costs; and handling energy, emission, or time-limited units", and therefore propose to give more detailed or prestrictive rules within the code.

[5] SEM Committee (2016a), *I-SEM Market Power Mitigation: Decision Paper*, SEM-16-024, page 46, para 7.2.1.

[6] SEM Committee (2016a), I-SEM Market Power Mitigation: Decision Paper, SEM-16-024, page 46, para 8.17.2.

2.2.2. Legal challenges provide no grounds for increasing RAs' "flexibility"

The proposals do not in fact give more flexibility to *market participants*, as claimed in the extract above, but only to the *regulatory authorities*. The Consultation Paper suggests this additional flexibility would reduce or avoid the burden of legal challenges. This argument is unconvincing.

In support of its argument, the SEM Committee discusses the Carbon Revenue Levy (CRL) and Gas Transmission Capacity Costs (GTC) as issues that provoked substantial legal challenges.[7] In these cases, the proposals of the RAs were found to be incompatible with the basic principles of regulation, the generation licence, and the BCOP, primarily because the RAs were proposing to hold offer prices below SRMC. *As a matter of economic principle, there are no circumstances in which holding market prices below SRMC will lead to efficient outcomes, because such a rule would remove any incentive for production.* Thus, the errors of interpretation were committed in these cases by the RAs, not by the generators. These errors were only prevented from taking effect by the generators' ability to mount a legal challenge, to the benefit of all customers.

The CRL and GTC examples do not therefore provide grounds for giving more flexibility to the regulatory authorities. Relying on those examples would imply that the regulatory authorities want to increase their scope to commit errors of interpretation, which cannot be the intention.

2.2.3. Lack of demonstrated advantages from greater "flexibility" for the RAs

In practice, the proposal to increase the regulators' "flexibility" (i.e. discretion) conflicts with the proposal to give "greater clarity…and detail" to market participants. By removing the economic definitions of SRMC and OC from the generation licence, the RAs would grant themselves the "flexibility" to impose offer prices below SRMC and without reference to opportunity costs. (Nothing in the Consultation Paper suggests that the RAs want flexibility to set offer prices above SRMC.) Any attempt to set offer prices below SRMC would harm both efficiency and competition, which would conflict with the RAs' statutory duties to promote these features of the electricity market. Preventing cost recovery would also conflict with the statutory duty to allow licensees to finance their licensed activities, unless the regulatory authorities can show how generators can recover any costs they are not allowed to include in offer prices.

2.2.4. Clarifying details does not require a different form of control

With regard to any lack of "detail" over appropriate costs, that "existing issue" could, in principle, be managed by clarifying definitions under the current BCOP – as indeed the SEM Committee has done from time to time, when necessary. This "existing issue" does not therefore require a new form of control, or the removal of the existing definitions and principles from the generation licence. Moreover, setting detailed rules would not avoid the

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7 SEM Committee (2016), Offers in the I-SEM Balancing Market – Consultation Paper, SEM-16-059, 7 October 2016, pages 11-12.

need to debate the "appropriate costs". In the first instance, this problem will arise when the initial rules are defined. It will emerge again, when drafting errors come to light (e.g. the omission of important costs) and when cost conditions change (e.g. when new costs arise, such as new taxes or levies on emissions). If the RAs do not set out any guiding principles in a stable format like the generation licence, the adaptations required by these continual problems will be unpredictable and will not be transparent. Such a regime will increase regulatory risk and discourage efficient investment.

2.2.5. Changing market structure does not significantly affect a principles-based BCOP

Finally, the SEM Committee argues that is does not regard the implementation of a minimal approach (meaning the current BCOP) as viable, because "the I-SEM is a more liberal market with numerous timeframes" and "very different in nature to the current market". These arguments about market structure do not stand up to close scrutiny.

The BCOP is not a "minimal approach", but rather a wide-ranging set of guiding principles and economic definitions. As explained below in this report, there are advantages to setting out principles when faced with complex and changing conditions, because detailed rules would too often obstruct efficient behaviour. The BCOP is therefore well placed to accommodate a new market structure.

The increase in the number of organised markets under I-SEM is irrelevant, since the RAs have already established that controls on the Balancing Market would be sufficient to control prices in other markets (through the effect of arbitrage, by which forward market prices depend on expected prices in real-time markets). All that is required is to adapt the definition of SRMC set out in the generation licence (and the reference to it in paragraph 6 of the BCOP) from a "Trading Day" to the period of a "Balancing Market Action". (Paragraph 11 of the BCOP, on time constraints, offers a useful precedent for defining a relevant time period.)

In this context, a Balancing Market Action means the change in output resulting from a single instruction from the TSO in the Balancing Market. Generators will not always know what total change in output the TSO will instruct, either when submitting their offer or when responding to an open-ended instruction to change their output level. Generators will therefore have to estimate the likely change in output. However, some such estimate will always be required for the construction of Balancing Market offer prices, under any option.

The Consultation Paper proposes a form of control (in paragraph 7A of Annex A) under which generators would calculate the incremental fuel cost of changing output by 1 MWh during an Imbalance Settlement Period (ISP).[8] This proposal is not practical. Balancing Market instructions often require generators to change their output by more than 1 MWh, over several ISPs, and to incur joint costs that are attributable to the *total* change in output

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[8] SEM Committee (2016), Offers in the I-SEM Balancing Market – Consultation Paper, SEM-16-059, 7 October 2016, Annex A, paragraph 7A on page 30, and also paragraphs 6 and 20 on pages 29 and 32 respectively.

rather than to individual units of energy.[9] In such cases, the generators would in any case have to allocate joint costs to some or all of the additional output – based on an estimate of the additional output that they will be instructed to provide.

Hence, the proposed definition of SRMC is poorly adapted to generator operating characteristics and impractical as a rule.[10] It will immediately prompt discussions – and potentially disputes – over the additional calculations needed to allocate joint costs, based on the estimated likely change in output required by a Balancing Market instruction. To avoid such disputes, the new code would have to recognise that generators need some flexibility (1) to estimate the change in output required by a Balancing Market instruction and (2) to decide a suitable allocation of the resulting incremental costs to individual units of energy (MWh).

We comment on the proposed new definition of SRMC[11] and propose an alternative based on amending the BCOP in Appendix B. Our amended version would make the current BCOP suitable for use within the I-SEM.

2.3. The Proposals Would Potentially Create Regulatory Risk and Hamper Competition

In the subsequent discussion of these proposals, the SEM Committee tries to specify how each "Option" would be defined and implemented. We comment on those Options below. However, even at the high level of the introduction, the proposals create two important sources of risk that will tend to hamper competition in the I-SEM.

1. The SEM Committee intends to extend controls to energy actions in the Balancing Market "if observed behaviour is deemed to warrant this". However, the Consultation Paper does not discuss what kind of behaviour would trigger such an extension of controls.

2. The footnotes to these bullets refer to document SEM-15-026 for a definition of energy and non-energy actions, and reproduced the text from page 13 of that document. However, these definitions are not precise: "Energy actions *can be broadly considered* as actions taken by the TSOs to address an overall imbalance between supply and demand" (emphasis added).

Each of these proposals raises concerns over regulatory risk and its dampening effect on competition.

9 Examples of joint costs include: (1) the costs of reconfiguring plant for a change in output; (2) any loss of efficiency during ramping; (3) the cost of any minimum change in output; and (4) the cost of buying the minimum traded volume of gas.

10 One possible reading of the proposed definition would require the generator to allocate all joint costs to the first unit of any change in output, since the increment to costs is incurred, in principle, as soon as output changes by even 1 MWh. That reading would produce very high offer prices, which would dramatically overstate the cost of subsequent output.

11 The proposed definition of SRMC is set out on page 30 of the Consultation Paper in Annex A, as clause 7A of the proposed "Balancing Market Offer Principles Code Of Practice" for Option 1.

First, if market participants are unsure what kind of behaviour would cause the RAs to extend controls to energy actions, they may act more cautiously and wrongly avoid competitive forms of behaviour.

- Different market participants may form different views as to what is acceptable, which by itself would distort competition and diminish the efficiency of operation. Some market participants may decide to avoid actions that would in fact be consistent with competition. The RAs' threat to extend controls would therefore hinder competition.

- To meet their statutory duty to promote competition, the RAs would need to remove as much uncertainty as possible over the kinds of behaviour that would prompt them to extend controls to energy actions. We can envisage two possible solutions:

  - either the RAs set out the specific conditions that would lead them to expand controls;

  - or else the RAs state that any decision to expand controls would apply the criteria and procedures of general competition policy (on the grounds that the precedents in competition policy provide a well understood basis for deciding on such interventions).

Second, even within the confines of non-energy actions, there are areas of regulatory risk that require attention to avoid hindering competition. We understand that the TSO will "tag" accepted offers as "energy" or "non-energy" *after* trades have taken place. The process for identifying energy actions and non-energy *ex post* is unpredictable, and somewhat subjective. The proposal also creates a perverse incentive for the TSO to tag energy actions as non-energy, in a discriminatory manner. These problems create regulatory risk and discourage some competitive behaviour, as explained below.

- There is some regulatory risk in the fact that actions will only be tagged as energy or non-energy after trades have taken place. Market participants will have wider discretion to set their offer prices for energy actions than for non-energy actions (or else it is meaningless to say that controls are limited to the latter). However, market participants will not know if their offer prices are subject to the controls or not. They may restrict their offer prices to meet the requirements of non-energy actions in ways that prevent them from competing effectively in energy actions. As a result, the uncertainty would hinder and reduce competition within the I-SEM energy market.

- The discretion accorded to the TSO to tag actions as "non-energy" raises another possibility, that the TSO uses this power to "discriminate down the supply curve", i.e. to keep the earnings of some generators below the market price, by tying the price they receive to their costs. Such discriminatory behaviour hinders competition in the market.[12]

[12] We understand that the TSO will select energy and non-energy actions based on an algorithm, rather than having full discretion to tag individual bids after their submission. However, the design of the algorithm is itself subjective and we understand that the TSO can adapt the algorithm over time with limited consultation.

These problems require attention before any new controls take effect, to preserve the potential for competition within the I-SEM. Given the need to retain some discretion and flexibility for dealing with new situations, the only workable solution is to set out a framework of principles that defines how the regulatory authorities will react in the future, as we discuss in section 4.4 below.

2.4. Discretionary Regulation Requires a Framework of Principles

Given the large forecast market shares of ESB set out in SEM-15-094, we are not surprised that the SEM Committee wishes to retain the right to extend controls to cover energy actions. However, the power to exercise discretion creates a responsibility to do so in a predictable and objective fashion. Otherwise, the resulting uncertainty will, by and of itself, harm competition.

The undesirability of poorly defined and discretionary interventions in competition policy was tested and demonstrated by the discussion of the Market Abuse Licence Condition (MALC) in Great Britain in 2000-2001. That process ended with the Competition Commission rejecting the MALC, in part because of the uncertainty it would have caused.[13] In terms of the SEM Committee's list of appraisal criteria, the Competition Commission concluded that this kind of discretionary intervention lacks *transparency*, harms *competition* and therefore reduces *efficiency*.

Unfortunately, the Consultation Paper adopts an approach similar to that rejected by the Competition Commission. In section 2.2 on page 7, the Consultation Paper states that "in the event that behaviour is *deemed by the SEM Committee to be unacceptable*, the SEM Committee will be prepared to develop and implement ex-ante offer controls either on individual participants or across the wider market if observed behaviour *is deemed to warrant this"* (emphasis added). However, the Consultation Paper provides no practical or objective definition of the behaviour that would be "deemed to warrant" intervention or that current and future SEM Committee members would "deem to be acceptable". This lack of definition opens the way to decisions with adverse consequences.

In the past, the regulatory authorities "deemed" it unacceptable for generators to include the Carbon Revenue Levy (CRL) in their offer prices, but the courts were able to correct that error, by reviewing the guiding principles in the generation licence and the Bidding Code of Practice. If the regulatory authorities could merely "deem" it unacceptable to include the CRL with no reference to guiding principles, market participants would have found it difficult to submit the decision to external scrutiny. The error would not have been corrected until the adverse consequences were apparent and already harming consumers' interests.

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13 Competition Commission, *AES and British Energy: A report on references made under section 12 of the Electricity Act 1989*, CC No. 453, 31 January 2001. The document is available via UK government archives at http://webarchive.nationalarchives.gov.uk/20140402141250/http://www.competition-commission.org.uk/rep_pub/reports/2001/453elec.htm
Paragraph 1.12 contains the following statement: "We have not therefore identified adverse effects which need to be addressed by the inclusion in the licences of AES and British Energy of a condition prohibiting abuse of market power. Moreover, we think that such a prohibition would cause uncertainty, because of the difficulty of distinguishing between abusive and acceptable conduct, and would risk deterring normal competitive behaviour." The Competition Commission expands upon the undesirable and anti-competitive nature of this uncertainty in the remainder of the report.

Therefore, whilst the desire to preserve flexibility is understandable, sound decision-making must rely on something more stable and objective than the subjective views of the regulatory authorities of the day to justify interventions in competition. The only practical means of overcoming this problem is to set out (and apply) clearly defined principles that allow market participants to anticipate when and how the regulatory authorities would intervene. Only then can market participants safely adopt efficient, competitive behaviour without fear of triggering sanctions. Only then can the quality of regulatory decisions be tested, before they take effect.

The need to set clearly defined principles (which we have described in comments on previous papers in this workstream[14]) applies both to the desire to extend controls and also to tightly defined rules that do not anticipate all possible future situations. It has important implications for the evaluation of both Option 1 ("Offer Principles") and Option 2 ("Offer Limits"), as we explain below.

2.5. Conclusion

The Consultation Paper proposes the introduction of bidding controls, in the first instance only on non-energy actions in the balancing market, but with the possibility of extending them in future to energy actions. The stated reasons for introducing new controls, and for putting them all into a new code, do not stand up to scrutiny.

The proposals would create regulatory risk for market participants, stemming both from the regulation itself and from the process governing changes to that regulation. In the short term, the design of the algorithm determining energy and non-energy actions is subjective and lacks transparency. In the longer term, there is no defined process for overseeing changes to the algorithm by the TSO, and no basis for market participants to know what behaviour might provoke an extension of the controls. This regulatory risk will discourage some competitive behaviour by market participants and therefore threatens to raise prices to consumers.

In order to diminish regulatory risk and to reduce costs to consumers, the SEM Committee will need to establish clear guiding principles for any bidding controls that are robust to changing circumstances and founded in economics. Prescriptive rules which become obsolete or do not reflect economic fundamentals will necessarily come under pressure over time and expose market participants to additional regulatory risk.

No attempt to define prescriptive bidding rules can ever reflect the economic fundamentals underlying market participants' bidding behaviour in all circumstances. The SEM Committee would need to substitute its judgement for market participants', without objective support. Market participants would be less able to hold regulatory decisions to account, even in cases where the SEM Committee directs bidders to bid less than their SRMC. Indeed, such direction is not a remote possibility and has occurred under the existing BCOP. A lack of legal recourse to ensure that efficient competitors are able to recover their costs and to operate efficiently would inject regulatory risk and ultimately raise prices for consumers.

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14 NERA (2016), *Review of the Capacity Remuneration Mechanism Local Issues Paper*, 22 September 2016, page 15.

3. Review of Bidding Arrangements in the SEM & I-SEM

3.1. The Legal Form of Controls has Real Economic Effects

Section 3.1 of the Consultation Paper notes that SRMC is defined by a Generator Licence Condition, whilst the use of Opportunity Cost to value each relevant cost item in SRMC is stipulated and explained in the BCOP. The Consultation Paper presents this separation of the drafting as if it were an accident, or even a mere administrative inconvenience. Later, the Consultation Paper proposes to address this inconvenience by putting all the rules in one subsidiary document, and to use the licence merely to enforce these rules. However, this discussion of legal instruments fails to consider the relative merits of entrenching different parts of the policy in different documents.

One reason for putting important statements of principle in the licence (such as the obligation to use SRMC and its definition) is the additional process of consultation and appeal that makes it difficult for future regulators to adopt arbitrary or ill-considered amendments. The consequent incentive to follow due process contributes significantly to the stability and predictability of the scheme, and to the minimisation of regulatory risk. It also protects future regulators from the consequences of ill-considered decision-making: by following due process and referring to established economic definitions in their decisions, regulators can be assured of making decisions that are less likely to be overturned, that provide greater certainty to market participants, and that better foster competition.

By contrast, putting rules in a separate document would take them outside the scope of some regulatory procedures and make them subject to change at the will of the regulatory authorities. Doing so would only be justified where there is a consensus that, from time to time, some matters need to be updated quickly to accommodate a new situation. This approach works at present for some aspects of the BCOP, but was not deemed suitable for guiding principles such as the economic definitions and uses of SRMC and OC. To give the required degree of long term stability, these concepts have to be set out in generation licences (or documents with equivalent change management processes), as guidance for any future changes in the BCOP. The Consultation Paper offers no grounds for departing from this approach, especially since it acknowledges the effectiveness of the BCOP over many years.

The identification of individual cost items and the basis of their valuation may be technical questions that need updating from time to time, if technological conditions change or new information comes to light. However, it would be more desirable to set out rules that accommodate changing cost conditions, or better still guiding principles that allow for all new situations, than to list a set of costs that is bound to become unduly restrictive in the future. The small number of amendments to the BCOP since its inception is testimony to the far-sighted nature of its drafting, which suggests it would be unwise to change the approach adopted in that document, unless a change in the market rules makes it strictly necessary. (Far from reducing the regulatory burden, an overly prescriptive set of rules would be subject to continual amendment and accompanying uncertainty both for the regulators and for market participants.)

The Consultation Paper states that "[i]n particular, the SEM Committee is minded that such clarity (along with additional flexibility) can, in part, be achieved by transferring details (e.g. calculation of SRMC) from the Generation Licence Condition 'Cost Reflective Bidding in the

Single Electricity Market' to a revised offer controls document."[15] However, merely transferring details from one document to another will not enhance "clarity". In practice, the "additional flexibility" offered by such a move would reduce the clarity of the rules, by opening up fundamental principles to the threat of amendment without due process. That threat would run counter to the SEM Committee's criteria of transparency, because the basis for future rules would be unclear to market participants. It would harm competition and efficiency by increasing regulatory risks and costs for consumers.

In deciding whether to set out controls in the licence or in industry codes, the SEM Committee makes a trade-off between (1) the stability and predictability offered by the licence and (2) the additional flexibility offered by codes. However, the reasoning set out in this section of the Consultation Paper is weak and unstructured. In order to give market participants comfort that it has applied its own criteria when deciding how to introduce controls, the SEM Committee should explain which elements of the controls would benefit from additional flexibility and why those benefits are more important than the benefits offered by the stability of conditions in participants' licences. Guiding principles for bidding should reflect the underlying economics of generation and should be stable over time. Accordingly, guiding principles belong in generators' licences, to provide the required degree of stability and certainty. Any prescriptive rules or calculations, which are intended to provide clarity but which may become obsolete, would ideally be placed within industry codes or similar documents, so that they can be amended quickly in the light of stable principles (but they should still be augmented by a rule allowing the inclusion of "any other components of SRMC", to prevent problems arising in the time before rules can be amended).

As we see it, important principles that should apply to all future controls would be more credible, if they were set out in the generator licence, as it provides more stability and predictability. The interpretation of such principles might still benefit from some codification, i.e. rules providing further guidance and summarising decisions on the interpretation of the principles in the licence. These rules would need to be capable of revision (always in accordance with the principles in the licence) if they proved to be incompatible with efficient behaviour, or if unforeseen situations led them to become unnecessary or inconsistent with new conditions.

3.2. Adopting Fixed Rules Cannot Dispel Disputes

3.2.1. Disputes over contractual or regulatory terms will arise in any complex environment

Section 3.2 of the Consultation Paper lists some disputes that have arisen over the current BCOP, including the ad hoc monitoring activities of the MMU and formal appeals over the treatment of the "Carbon Levy" (i.e. the Carbon Revenue Levy) and gas transmission charges. The Consultation Paper notes the greater or lesser use of resources by the MMU and/or the SEM Committee in dealing with these disputes. However, the Consultation Paper appears to imply that these disputes can be avoided, and the cost of disputes reduced, by replacing

[15] SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7th October 2016, page 13.

statements of principle with more tightly defined rules. For instance, later, in the evaluation of Option 2, the SEM Committee writes:

> "Historically, as discussed in Section 3.2, there has [sic] been many challenges in the SEM as to whether to include, and how to value, a number of cost items. The high level nature of the principles arrangements have led to debate as to whether some costs should be included in generator offers, and to how some cost items should be valued. This has been extremely resource intensive for the RAs and affected participants, and at times has led to resources being diverted from other areas. It has also led to issues around transparency and how different units value similar cost items. There have also been problems with differing jurisdictional arrangements and their impact upon generator bids. For example, units in Ireland have the ability to include Gas Capacity Exit Costs in their bids, whereas generators in Northern Ireland do not. This is because no market for the purchasing of short-term capacity of this product exists in Northern Ireland."[16]

Concluding that more tightly defined rules would avoid disputes is naïve – and an incorrect basis for any general prescription to act – for the following reasons:

1. The two formal appeals over the BCOP arose because of misguided attempts by the regulators of the day to deny generators the opportunity to recover (i.e. to include in their offer prices) cost items that legitimately formed part of SRMC – the Carbon Levy and the short-term (opportunity) cost of gas transmission. These disputes could have been avoided if the regulators of the day had taken more time and resources to consider the issues at stake. In the end, the court actions corrected a regulatory error.

2. In any case, the resources used to resolve these disputes were trivial administrative costs, compared with the potential costs to efficiency and competition in the generation sector that would have been imposed by allowing these misguided rules to stand. Focusing solely on the administrative costs of appeals gives a distorted view of their costs and benefits. It was beneficial to consumers overall that these appeals were allowed to run their course.

3. Replacing statements of principle with narrowly defined rules will not eliminate the potential for disputes, but will merely replace disputes over the interpretation of the principles with disputes over the design or application of new rules. Any fall in the number of disputes that occurred in practice might merely reflect the increased difficulty of holding regulatory decisions to account under the new arrangements, rather than any improvement in the quality of regulatory decision-making. In other words, if the process for disputing regulatory decisions were made so onerous as to discourage challenges, the number of disputes might fall, but only because market participants would tolerate *greater inefficiency* in the bidding rules before triggering appeal procedures.

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16 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7th October 2016, page 24.

The last of these points arises from an important economic principle, namely the inevitable "incompleteness" of any contract (civil or social).[17] According to this principle, it is impossible (or prohibitively expensive) to draft a contract (or, in this context, a set of rules) that foresees every possible eventuality and defines the appropriate response in each case. *Either* contracts must offer some flexibility to assemble a response to new circumstances when they arise (guided by some statement of principles), *or* the contracting parties must adopt a different form of organisation (i.e. join together in a firm, instead of a contract). Since regulatory authorities cannot adopt the latter policy, they must accept the former, however reluctantly. Drafting more prescriptive rules is therefore no substitute for a set of guiding principles, but helps only where rules help to codify the current understanding of those principles.

3.2.2. Lack of detail, guided by principle, is an efficient response to uncertainty

The Consultation Paper notes two areas where the BCOP is not very detailed. According to the SEM Committee, the BCOP only provides (1) "minimal detail on: Start-up and No Load costs; VOM costs; and Handling energy, emission, or time-limited units" and (2) "a definition of Opportunity Cost that can be applied to any cost item, but does not define or explain any other cost items."[18] In the view of the SEM Committee, "any revised offer control may need to address these issues under I-SEM."[19] We agree that the SEM Committee should address any material cases of imprecise or incomplete definitions in the BCOP (and indeed any other "issue") which prevent the current BCOP from operating effectively. However, the SEM Committee has erred in merely assuming that there are problems with the current drafting of the BCOP and that the correct way to address them is by prescribing detailed rules. Moreover, the SEM Committee's proposed revisions are at odds with its view that the enforcement of the current BCOP has been effective.[20]

At the very least, we would have expected the SEM Committee to have considered the reasons why these elements of the BCOP were drafted as they were. One possible reason for the current wording is that no further detail is required, since there is near-universal consensus on the nature of these cost items. Another possible reason is the opposite one – that there is no consensus as to the precise nature of these cost items, so flexibility of interpretation is required to avoid imposing rules that deny cost recovery and harm competition or efficiency. The SEM Committee should have considered both these possible

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[17] The principle of incomplete contracts is so important for real-world economics that the 2016 Nobel Prize for Economics was awarded to two economists who have devoted their academic careers to investigating its effects, namely Oliver Hart and Bengt Holmström.

[18] SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 14.

[19] SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 14.

[20] In particular, the SEM Committee states that: "the SEM Committee's view is that the current BCOP has been effectively enforced through monitoring and investigations, and it has likely prevented market power abuses." SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 10.

reasons (and others) for adopting a high-level approach to individual cost items, rather than selecting a highly detailed – and potentially damaging – rule.

The SEM Committee's conclusion that detailed rules will necessarily be more efficient than adapted versions of the existing principles is wrong, and appears to have been driven by a false assumption. The SEM Committee has wrongly assumed that disputes arose only because of inadequate drafting in the BCOP, which can be resolved by adopting tightly defined rules. It has not considered why – and hence when – it is advantageous to set out high-level rules or guiding principles for defining costs and offer prices. After all, tightly defined rules may contain errors and will inevitably fail to anticipate all future circumstances. Either problem can lead to severe operational problems and disputes. The most efficient approach would combine (1) tightly defined rules where matters are clear (or indeed no rules at all where the interpretation of principles is so clear that breaches can be dealt with by ex post competition law), with (2) robust and stable principles for addressing new situations and for resolving disputes.

3.3. Summary Comment

The SEM Committee has never questioned "the effectiveness of the existing BCOP" and acknowledges it once again in the opening sentence of section 3.3 of the Consultation Paper. The performance of the BCOP therefore provides no grounds for changing the current approach, except to the extent that is required to accommodate new market institutions under the I-SEM (i.e. switching the focus from day-ahead markets to balancing markets). However, the SEM Committee has used this Consultation Paper to raise questions unrelated to the creation of the I-SEM.

In particular, chapter 3 of the Consultation Paper raises objections to the form of the current controls derived from the RAs' experience of applying them. Our analysis of these objections shows that they arise from:

(1) a purely partial application of appraisal criteria (unduly favouring administrative convenience to the regulatory authorities and their preference for "flexibility", to the exclusion of other criteria such as transparency and efficiency); and

(2) a misunderstanding of the cause and nature of disputes over the interpretation or design of regulatory rules. Such disputes are inevitable, due to the "incompleteness" of any rules.

In any case, disputes need not be regarded as a flaw in the system, but rather as the process for providing greater clarity. The opportunity to dispute the market rules provides an important protection against regulatory failure: if the SEM Committee were to set offer price limits below actual marginal costs, market participants would exit the market and security of supply would be threatened. The prospect of contesting offer price limits lessens the chance of such outcomes and mitigates regulatory risk, as long market participants can refer to a stable and clearly defined basis for such limits. Setting out such principles in licence conditions provides clarity and stability, and therefore protects consumers as well as market participants from regulatory failure. Any delay in amending offer limits to comply with these principles would distort competition and reduce efficiency. Rather, Option 2 would only lead to efficient outcomes if these underlying principles effectively determined bidding behaviour, and offer limits merely tracked these bidding costs at each point in time.

The Consultation Paper therefore follows a truncated decision-making process which fails to consider key questions in the design of the rules. Instead, it rushes headlong towards conclusions that are premature, and possibly prejudicial. As a result, Chapter 3 of the Consultation Paper gives the SEM Committee no procedural or intellectual basis for the proposals that follow later.

4. Offer Control Options for the I-SEM

4.1. The SEM Committee Has Not Used Consistent Appraisal Criteria

Below, we discuss the two Options set out in chapter 4 of the Consultation Paper. Some of our comments apply equally to both Options, but we have followed the structure of the Consultation Paper for ease of reference.

It is notable that the discussion of the two Options is conducted almost entirely without reference to the SEM Committee's usual appraisal criteria. As we note below, the proposals in chapter 4 are set out for the most part as arbitrary "views" of the SEM Committee, without any justification in logic or fact. The Consultation Paper does not set out the consequences of these proposals for real operations or consider whether they are effective, targeted, flexible, practical, or transparent, let alone how they will affect competition and efficiency. The SEM Committee's alternative approach, of identifying "advantages" and "disadvantages" for each Option, begs the question as to what each Option is being compared with. If the basis of comparison varies arbitrarily between either the current BCOP or the other Option or no controls at all, the evaluation will be incomplete and inconsistent, leading to unreliable conclusions. There is no indication that the SEM Committee has appraised the Options against stable and consistent criteria.

This failure to carry out a proper evaluation has led the SEM Committee to make a number of errors, as explained below.

4.2. Option 1: Offer Principles

Option 1 is described in the Consultation Paper as a set of offer principles, similar in approach to the current BCOP. However, in practice, the option is set out as a set of prescriptive rules defining the limited range of costs that generators may include in their offer prices, and how to calculate them. The SEM Committee's current proposals for those rules exclude (for no good reason) important categories of cost, which may threaten cost recovery, undermine competitive behaviour and put security of supply in danger.

4.2.1. Redefinition of SRMC

The SEM Committee offers two criticisms of the current definition of SRMC. Those criticisms, as set out on page 16 of the Consultation Paper, can only be based on a misunderstanding and are incorrect or invalid.

The SEM Committee frames the first criticism with reference to the statement that "SRMC is an incremental, not total, cost", a statement with which we agree. The SEM Committee appears to believe that the existing definition of SRMC in the generation licence is inconsistent with "standard economic definitions", presumably in the belief that it measures a "total, not incremental, cost". However, that belief is incorrect.

The generation licence currently defines SRMC as the *difference* between two estimates of total cost – one if the generator produces output, and one if it does not. (See table 3.1 of the Consultation Paper.) This difference between two estimates of total cost is precisely the incremental cost of the output concerned. This criticism of the current BCOP is therefore incorrect.

The second criticism is stated as "Not all daily costs should be included in SRMC because some of those cost items are fixed for the day and do not vary with the level of generation". Again, we agree with the statement that fixed costs should not be included in SRMC. However, the current BCOP already excludes any cost items that are "fixed for the day" from the definition of SRMC. By definition, such fixed costs would appear in both estimates of total cost, i.e. both with output and without output. Fixed costs would be eliminated from the estimate of SRMC by taking the difference between the two estimates of total daily costs.[21] The current definition of SRMC therefore fulfils the condition set out in the Consultation Paper. The second criticism of the current BCOP is therefore invalid.

Thus, the criticisms of the current definition of SRMC articulated in the Consultation Paper can only be based on a misunderstanding of the relevant text.

The SEM Committee attaches a further, but distinct, observation to these criticisms: namely that "there is an issue with the 'Trading Day' basis of the SEM definition." This observation is relevant, given the switch in focus from SEM day-ahead markets to I-SEM real-time Balancing Markets. The Consultation Paper concludes (page 16) that "the definition should be defined for half-hourly Imbalance Settlement Periods (ISP)". That conclusion is unduly restrictive.

Some Balancing Market actions require an increase in output and incur additional costs that are spread over several half-hourly ISPs. These costs may be called "joint costs". (They arise jointly from linked outputs produced over several periods, and reflect a general property of the generator cost function known as "non-convexity".[22]) These joint costs are undoubtedly incremental costs of selling output in the Balancing Market, and should be included within any definition of SRMC. Such costs can sometimes be identified explicitly *a priori*, but must sometimes be found by comparing the total costs of operation with and without the change in output required by the Balancing Market. This narrowing down of the time period, from one day to several half-hour ISPs, would require only that the current definition of SRMC is amended to refer to the period of each Balancing Market Action, rather than to the Trading Day in all cases (although the Trading Day may be relevant to some Balancing Market Actions).

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[21] In mathematical terms, the daily costs of a generator consist of F, the fixed costs of running the plant, and V, the variable costs of producing output. The current BCOP requires generators to estimate the daily cost of running (F+V) and to subtract the daily cost of not running (F). As long as total costs are correctly estimated both cases, the resulting difference always equals V, the variable costs of output.

[22] The model of "perfect competition" requires a "convex cost function", meaning that the cost of increasing output by one unit is always higher than the costs saved by reducing output by one unit. Unfortunately, the costs of generation (indeed, costs in many industries) do not follow this pattern precisely. The cost of increasing output may sometimes be less than the cost saved by reducing output, so that costs are "non-convex" overall. For instance, the no load cost of generation represents a non-convex cost, since it is incurred to produce 1 MWh of output, but does not increase if production increases to 2 MWh of output or more. In paragraph 24 of Annex 1, the SEM Committee has recognised this problem by requiring generators to adjust their no load price "to ensure that the incremental offer curve submitted by the generation set or unit is monotonically increasing" (another way of expressing the requirement for "convexity").

Moreover, the joint cost of output produced over several half-hours cannot be attributed to any single MWh of output, or even to Balancing Market sales in any single half-hour, except by applying some accounting rule, such as a *pro rata* allocation, or an allocation to peak periods. (Under the current BCOP, generators must apply similar allocation rules to the joint costs of output across a Trading Day.) It would be undesirable to oblige market participants to consider each half-hour ISP separately. Such a rule would either lead to joint costs being attributed to output in the moment when they were incurred (e.g. always in the first half-hour of the BM action) or to generators being denied the opportunity to include such costs in their offer prices or to recover them at all (and it is not clear how else generators can recover such costs). Neither of these outcomes would produce Balancing Market prices that were truly cost reflective or likely to encourage efficient outcomes.

4.2.2. Eligible Cost Items

The SEM Committee makes the sweeping generalisation that maintenance costs are not variable costs:

> "Within Option 1, the SEM Committee clarifies what variable operational costs that can be included as eligible costs items. However, under Option 1 maintenance costs are not considered variable in nature and are therefore not considered by SEM Committee as eligible cost items for inclusion in offers." [23]

However, the SEM Committee offers no evidence that maintenance costs are never variable in nature, i.e. that they are never related to output. This statement is simply an assertion unsupported by fact. Moreover, this statement is incorrect, since generation plant (like many other machines) incurs some maintenance costs in proportion to its output or hours of operation.[24] The SEM Committee is therefore wrong to conclude that all maintenance costs should be excluded from SRMC.

The SEM Committee's cavalier dismissal of maintenance costs in the Consultation Paper is all the more incomprehensible, given that the SEM Committee has *previously* considered such costs and explicitly decided they should be included in generators' SRMC. Box 4.1 on page 24 below contains an extract from the SEM Committee's Final Report on a 2008 Inquiry into complaints about bidding behaviour. In this extract[25] (*emphasis added*), the SEM Committee states that:

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23 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 16.

24 The Consultation Paper discusses "periodic" maintenance (akin to a car's six-monthly service) as a time-related fixed cost, but overlooks the kind of maintenance outage that must be taken after a certain number of hours of operation (akin to a car's need to be serviced after 6,000 miles). Each hour of operation uses up the remaining life of the plant and brings such outages closer. It would be perverse not to treat the associated costs as variable (output-related) or as part of SRMC, particular if the generator concerned is running primarily for Balancing Market purposes.

25 SEM Committee (2008), *Complaints on Bidding Practices in the Single Electricity Market: SEM Committee Inquiry*, Final Report, SEM-08-069, 12 June 2008, pages 31-32.

- it "does not consider that a generator should be required under its Licence to *incur significant avoidable costs without the prospect of being able to recover them*, always excepting the sunk costs of past investment decisions";
- "that *all the avoidable costs outlined above* – the *additional O&M expenditure*, the additional equipment costs, the increased risk of failure to plant and equipment as a result of the plant's running regime and the concomitant loss of revenue from capacity payments and infra-marginal rents from SMP – *are allowable costs*"; and
- "To do otherwise could *threaten the development of efficient new entry and effective competition*, given that it may dissuade generators from entering the market if they perceive that they may incur irrecoverable forward-looking costs when doing so."

The view set out in the Consultation Paper is the reverse of these statements, but is offered without any justification for the change of the SEM Committee's opinion.

Box 4.1
The SEM Committee's Statements on Maintenance Costs and Foregone Revenues in 2008 (Extract)

"9.7. The SEM Committee considers that the BCOP and Licence conditions require that bids are cost-reflective. Bids should therefore take account of all avoidable costs incurred by a participant, taking account both of the costs of running and the costs of not running. The SEM Committee does not consider that a generator should be required under its Licence to incur significant avoidable costs without the prospect of being able to recover them, always excepting the sunk costs of past investment decisions. All avoidable costs should be capable of being recovered through some element of the participant generator's commercial offer data, including the prospective loss of capacity payments and inframarginal rent from SMP as a result of an increased number and duration of outages that can be explicitly linked to the running regime of the plant.

9.8. Accordingly, the SEM Committee considers that all the avoidable costs outlined above – the additional O&M expenditure, the additional equipment costs, the increased risk of failure to plant and equipment as a result of the plant's running regime and the concomitant loss of revenue from capacity payments and infra-marginal rents from SMP – are allowable costs.

9.9. To do otherwise could threaten the development of efficient new entry and effective competition, given that it may dissuade generators from entering the market if they perceive that they may incur irrecoverable forward-looking costs when doing so. Operation within the market must be economically viable for competition to flourish. The SEM Committee considers that this can only be achieved by ensuring that all avoidable costs are recoverable."

Source: SEM Committee (2008), Complaints on Bidding Practices in the Single Electricity Market: SEM Committee Inquiry, Final Report, SEM-08-069, 12 June 2008, pages 31-32.

The position in the Consultation Paper, that operation and maintenance costs are not variable, also directly contradicts the SEM Committee's *current* position in documents published as part of the CRM work stream. In setting the price cap for the CRM, the SEM Committee states that it assumes that market participants will be able to recover VOM costs from the energy and ancillary services markets:

> "The above numbers [used for setting the price cap] use NFOC [Non-Fuel Operation Cost] as a proxy for Fixed Operating & Maintenance (FOM) costs, which a generator may not be able to recover in a competitive energy market. However, it is likely that the NFOC contains a proportion of Variable Operating & Maintenance (VOM) costs which can be recovered via the energy or ancillary service markets, as well as FOM costs." [26]

The SEM Committee goes further still and proposes a division of Operational and Maintenance costs into variable and fixed components. It argues PJM provides "the best explanation" of which costs are variable and which are fixed and states that variable operating costs "covers major maintenance (which is start-based), and consumables and waste disposal which is assumed related to running." [27] This view is not definitive or universal. Indeed, one's view of maintenance costs may depend on running regimes. If generator plant runs baseload, its output is predictable and maintenance outages may appear as fixed (i.e. periodic) costs. If generator plant provides mid-merit or peaking generation, its output and running hours will vary from year to year. Maintenance outages would then most likely be due after accumulating a certain level of total output or a total running hours, in which case they would be a variable cost of "wear and tear".

Despite the SEM Committee's previous acknowledgement that some Operational and Maintenance costs are variable, the Consultation Paper takes a quite different view, without offering any explanation. Option 1 explicitly excludes "long-term maintenance costs" from both incremental bids and offers (clause 18) and start-up costs (clause 22c).

Nothing in the Consultation Paper rules out the existence of variable maintenance costs. Failing to allow recovery of these variable costs in bids will run the risk of forcing market participants to price below their SRMC, introduce incentives to withdraw capacity and distort competition and dispatch.

4.2.3. Revision to the Definition of Opportunity Cost

The SEM Committee is proposing to remove the BCOP's existing provision for including "reasonable provision for increased risks". The SEM Committee argues that another part of the BCOP defines opportunity costs in terms of a "benefit foregone in employing the cost item for the purposes of electricity generation", and "increased risks" do not represent a

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[26] SEM Committee (2016), Parameters Consultation Paper, SEM-16-073, 8 November 2016, para 6.3.23.

[27] SEM Committee (2016), Parameters Consultation Paper, SEM-16-073, 8 November 2016, para 6.3.28.

benefit foregone, but an addition “on top of the standard definition of opportunity cost”. [28] This conclusion is perverse.

The provision for increased risks in the BCOP does not depart from the concepts of cost items and benefits foregone. The precise reference is to “reasonable provision for increased risk to plant and equipment as a result of the operation of a generation set or unit”.[29] It merely allows for the inclusion of costs that are contingent on uncertain events, but which the rational operator of a competitive generator would still take into account when making efficient business decisions.

For example, if generation plant develops a fault, continuing to operate it may run the risk that the fault is exacerbated and the costs of repairing it rise (possibly by a large amount). This risk forms part of the opportunity cost of the generator: the “benefit foregone” from continuing to operate is the difference between the cost of repairing the fault now and the higher – possibly much higher – cost of repairing it later (adjusted also for any difference in revenues between the two scenarios – see below). If the generation plant continues to run to fulfil a Balancing Market trade, the additional risk of a more expensive repair is part of the SRMC of the associate output. The level of that cost item may be probabilistic – varying from zero, if the plant survives without incident, to very large, if running with the fault ends in a catastrophic failure. The provision for increased risks does not contradict or depart from the principle of opportunity cost, but usefully clarifies the right of generators to allow for cost items that are uncertain.

Removing the provision for increased risks would decrease clarity, increase regulatory risk, and potentially deny generators the opportunity to recover costs, or at least to include them in their offer prices, when those costs form a legitimate part of SRMC. The SEM Committee’s proposal to exclude risks from the definition of SRMC may therefore harm competition and efficiency. For instance, a market participant may have an incentive to declare a maintenance outage, rather than to generate in a particular half hour, to avoid incurring the risk of additional costs, if it cannot include the costs of that risk in its offer price. Where the plant would have contributed to system security, that incentive would work to the detriment of consumers.

In the next section of the Consultation Paper, the SEM Committee announces its “view” that “costs included in SRMC should be actual costs incurred as a direct result of increased generation rather than an estimated cost based on probabilities and theoretical costs.”[30] However, it provides no basis for this view, which is inconsistent with any standard definition of economic costs, opportunity costs or SRMC, and which is unworkable for at least two reasons.

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28 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 16.

29 BCOP, paragraph 8.(iii).

30 SEM Committee (2016), Offers in the I-SEM Balancing Market – Consultation Paper, SEM-16-059, 7 October 2016, Section 4.2.4 on page 17.

First, given that generators must prepare their offer prices before they actually produce the output, all offer prices must be based on an estimate of the costs they will incur. Accordingly this "view" might be taken to exclude any cost item that is part of SRMC. Therefore, the SEM Committee's view that estimated costs should not be included in offers as a matter of principle is unjustified and unworkable.

Second, the SEM Committee's "view" that "theoretical" costs should be excluded provides no insight into whether or not risks form part of SRMC, but merely hints at the evidential standard that should apply. The SEM Committee may reasonably take the view that it should exclude *purely* theoretical costs whose existence market participants cannot support with evidence. However, the SEM Committee should be equally willing to accept "potential" or "risky" costs for which there is good evidence. If market participants can provide evidence that generating causes certain risks, then any attempt by the SEM Committee to disallow them would jeopardise efficient, competitive behaviour to the detriment of consumers.

4.2.4. Foregone Revenues

Similar misunderstandings lie behind the proposal to remove the provision for "foregone revenues", which is therefore unjustified by logic or facts.

The SEM Committee's *first error* is to suggest that "foregone revenues are *arguably* not opportunity costs associated with any single input used in electricity generation" (emphasis added). The Consultation Paper makes this assertion without any supporting argument, and recognises the point as only "arguable", rather than self-evident, presumably because the regulatory authorities are aware that the generators have been allowed to include some foregone revenues as an opportunity cost under the current BCOP. In fact, foregone revenues are a well-established kind of opportunity cost, arising in this case from the loss of a generator unit (the "input used in electricity generation").

Therefore, even if the SEM Committee wished to issue a clarification that forecasts of future revenues foregone cannot be included in the definition of opportunity cost, it would have to address two arguments: (1) whether the disallowance would have any impact on the willingness to participate in the Balancing Market, and hence the efficiency of Balancing Market performance; and (2) whether other foregone revenues are legitimate components of Opportunity Cost and hence SRMC.

With regard to point (1), the SEM Committee has not provided any analysis of the consequence of its proposal. As for point (2), the view stated in the Consultation Paper is the reverse of the SEM Committee's statement about foregone revenues in the 2008 Final Report quoted in Box 4.1 on page 24 above. In that document, the SEM Committee stated that foregone revenues were allowable costs:

- "all the avoidable costs outlined above – the additional O&M expenditure, the additional equipment costs, the increased risk of failure to plant and equipment as a result of the plant's running regime and *the concomitant loss of revenue from capacity payments and infra-marginal rents from SMP* – are allowable costs."[31] (*emphasis added*)

The Consultation Paper provides no explanation for reversing its view now. If the explanation lies in some difficulty interpreting the wording of the current BCOP (such as "input used in electricity generation"), the current Consultation Paper would have provided an opportunity to clarify or amend that wording. The SEM Committee has not considered any alternative wording. Indeed, section 4.2.5 of the Consultation Paper specifically adopts, as one of the concepts for valuing Gas Transmission Capacity (GTC), "the amount which [generators] would realise by disposing of the unused GTC" – in other words their foregone revenue, suggesting that there is no problem with the current formulation of terms. The SEM Committee's reversal of its position on foregone revenues is therefore arbitrary and selective, as well as unjustified.

The SEM Committee is therefore adopting arbitrary, selective and inconsistent views in its proposed treatment of foregone revenues, for no good reason. Foregone revenues represent Opportunity Costs and SRMC in some circumstances. Instead of merely asserting that SRMC "should be actual costs", the SEM Committee should have set out the consequences of departing from the principle of Opportunity Cost and the potential under-pricing of Balancing Market actions.

The SEM Committee's *second error* is to focus on "speculative" costs and to confuse "speculative" forecasts with the use of future prices to calculate Opportunity Costs. The Consultation Paper states that the SEM Committee would not allow generators to use "a potential future fuel price in the opportunity cost of using fuel to generate electricity" and argues instead for the use of "actual costs" or "actual fuel prices".[32] In practice, of course, it is sometimes the potential future fuel price of *replacement* fuel (not the "actual" price paid for the fuel currently being consumed) that defines the current Opportunity Cost of generation.

With regard to GTC, the SEM Committee has also overlooked an important case where "foregone revenues" define Opportunity Cost without reference to forecasts. However, using forecast prices to value the foregone revenue of GTC would be no different from using forecast fuel prices to calculate the replacement cost – i.e. the opportunity cost - of fuel used in generation. The SEM Committee may wish to set high standards for the evidence used to justify offer prices based on forecast information, but cannot reasonably rule out the use of such forecasts entirely.

Indeed, the whole concept of Opportunity Cost is intended to draw attention away from accounting costs and to provide a measure of the economic costs of production which guide efficient choices. Prices actually paid rarely provide a useful measure of opportunity costs,

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31 SEM Committee (2008), *Complaints on Bidding Practices in the Single Electricity Market: SEM Committee Inquiry,* Final Report, SEM-08-069, 12 June 2008, page 32.

32 SEM Committee (2016), Offers in the I-SEM Balancing Market – Consultation Paper, SEM-16-059, 7 October 2016, page 17 and page 31 (condition 15 of the draft code of practice in annex A), respectively.

which must be taken from other sources.[33] The SEM Committee might wish to rule out purely "speculative" estimates, but this concern addresses the objectivity of regulation and affects the rules of evidence used to justify certain offer prices. This concern cannot ever rule out the use of "potential future prices", since they are intrinsic to the concept of Opportunity Cost. The SEM Committee's proposal is therefore inconsistent with the concept of Opportunity Cost.

4.2.5. Conclusion

SRMC is an incremental cost concept. The SRMC of generation is the difference between the total costs incurred with, and total costs without, generating output over a given period. It will be important for competition and efficiency that any incremental costs incurred in order to generate over multiple ISPs are allowed in offer prices, but the SEM Committee's current proposals appear to have disallowed a number of such costs.

Some maintenance costs are related to hours of running or levels of output, and so form part of SRMC. The proposal to disallow maintenance costs is therefore unduly restrictive – and contradicts other statements by the SEM Committee. The proposal to remove the provision for costs resulting from increased risks has no basis in economics, logic or fact, and also contradicts previous decisions reached by the SEM Committee. It would reduce transparency by making the rules less clear and consistent. It would undermine generators' ability to recover costs, thereby hindering competition and reducing efficiency. In some cases, forecast revenues form part of opportunity cost, so there is no rationale for the SEM Committee's proposal to exclude them in their entirety, either.

4.3. Option 2: Introduction of Offer Limits

The SEM Committee's second proposed Option is to impose limits on market participants' offer prices ("offer limits"). The regulatory authorities would take the initiative in calculating these offer limits, but in many other respects this proposal is similar to Option 1.

4.3.1. Methodology behind the calculation of the Offer Limits

The offer limits imposed by the SEM Committee will only be credible if they closely track the SRMC of generation. Generators would be forced into uneconomic decision-making and would be likely to contest offer limits that frequently fell below their SRMC. On the other hand, if offer limits were set significantly above the SRMC of generation, the SEM Committee would come under pressure to revise the limits downwards, to prevent market participants from bidding anti-competitively.

The SEM Committee intends to set offer limits on a quarterly basis, and claims that this decision would "strike a good balance between the desire to track movement in input costs

[33] The only reference to "actual" costs in the BCOP concerns start-up and no load costs, but arises only in a provision allowing generators to bid something else – if "it can be demonstrated to the satisfaction of the Authority or the Commission" that bidding "actual" costs (however they are defined) would "distort the true economics of the generation set or unit." (BCOP, paragraph 10.)

without encumbering itself or industry with an onerous process".[34] It is not clear how such an inflexible rule could ever possibly reflect the SRMC of generators in the market, since generators' opportunity costs change much more frequently than quarterly, often by large amounts, especially in the case of fuel prices.[35] Neither is it clear what "onerous" process would be necessary to index the offer limits to more frequent measures of the SRMC of generation, such as spot prices for gas and/or fuels, to ensure that the offer limits more closely reflect the opportunity costs of market participants.

In addition to imposing fixed offer limits, the SEM Committee proposes to retain discretion and control over adjustments to the method of calculating them. In particular, the SEM Committee will "retain an ability to carry out an ad hoc review at any stage should there be any extreme movements in any of the generators [sic] costs, such as in the event of a spike in fuel price" and review the method "as required going forward".[36] These provisions demonstrate how the SEM Committee realises that blind application of offer limits will not be efficient because simplified calculations will not necessarily track generators' costs. However, the open-ended nature of these provisions does nothing to restrict the SEM Committee's ability to interfere in market participants' pricing decisions and therefore exposes market participants to regulatory risk. For instance, the SEM Committee would have sole authority to judge whether or not movements in costs were sufficiently "extreme" to merit adjustment and whether or not the methodology needed to be revised.

To have any chance of encouraging efficient, competitive behaviour by market participants, the SEM Committee's ability to adjust simple offer limits would need to be bound by clear economic and regulatory principles. Without such principles to guide regulatory decisions, the necessary adjustments to the rules would be prone to arbitrary choices, instability and a reliance on trial-and-error to find a sustainable position. Unguided by principles, such a process might be never-ending. Given a set of guiding principles, Option 2 might offer some hope of providing the stable guidance that market participants need. Therefore, a desire to avoid setting out the kind of principles that currently underpin the definition of SRMC and OC provides no basis for selecting Option 2.

Once augmented by a set of principles, Option 2 would share many of the features of Option 1. Responsibility for calculating offer prices rests with the generators in Option 1, and with the regulatory authorities in Option 2, but in both cases the SEM Committee would have to consider from time to time which types of cost may be included in generators' offer prices. Although better than the options as defined in the Consultation Paper, these variants would still hamper competition, if detailed but outdated rules were not changed quickly enough.

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[34] [TBD]

[35] It would wrong to argue that generators can hedge against quarterly offer limits by buying fuel on quarterly contracts. As mentioned above, such fuel prices are irrelevant when defining the opportunity cost of generating in the BM. Tying offer prices to the fuel prices in quarterly contracts would discourage efficient generation or consumption, and would hinder competition.

[36] SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 21.

4.3.2. Grouping of generator units

The Consultation Paper is unclear over the extent to which the SEM Committee will impose offer limits on individual generators or on groups of generators. Whilst in principle the SEM Committee intends to define offer limits by referring to the costs of groups of generators, its proposals do identify some exceptions. For example, the Consultation Paper states that:

> "The SEM Committee also envisages instances where the placing of certain generators into groups may not be appropriate. For example, if a plant is 'must run' in the market for system reasons, then it will have no incentive to compete against any other unit and will likely submit an offer equal to the offer limit in all instances. In this case, the SEM Committee will consider whether it would be appropriate to impose a separate offer limit on that particular unit." [37]

The SEM Committee's sole example applies tighter offer limits to more valuable, constrained-on generators, than to other, similar generators. It is not clear why such valuable generators should be subject to a lower offer limit than generators that are competing in the general market. The SEM Committee certainly does not justify its proposal for grouping plant using its normal criteria of transparency, flexibility, efficiency and competition.

In this example, the SEM Committee seems unsure as to the basis of the offer limits for this group of generators. If, as discussed earlier, offer limits reflect the SRMC of generator output, there is never any reason to set them lower, as that would discourage the generator from running (a serious outcome, when applied specifically to plant required to support the system). The SEM Committee's argument seems to rest on the assumption that the offer limit for this type of generator is above their costs of operation, and also possibly above the market price of electricity. However, that seems to imply an error in setting the offer limits, rather than a need to revise the regulatory framework for some, but not all, generators in a group.

In practice, a stable rule would only group generators where the costs of those generators were similar. Any other rule would risk treating some generators discriminatorily and denying some generators the opportunity to recover their costs (if their offer limit were too low).

We have already noted that the regulatory authorities will find it administratively burdensome to specify allowable costs for individual generators, under both Option 1 and Option 2. Any errors, by which short run marginal costs are mistakenly excluded from offer prices, will deny cost recovery, distort incentives, and threaten competition, efficiency and security of supply. The regulatory authorities would therefore have to take care to ensure that offer limits (or the equivalent rules under Option 1) were never lower than each generator's costs. Under the proposal to group generators, the regulatory authorities would have also to ensure that offer limits were never lower than the costs of *any* generator in the group, and ideally that *all* generators in the group had similar costs. Achieving this outcome would require the

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37 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 21.

SEM Committee to scrutinise the costs of each generator in detail, to check that they were similar. It is impossible to see how setting group-level offer limits would reduce the regulatory burden of Option 2.

4.3.3. Exceptions management

The SEM Committee's proposals for exceptions management show further recognition that simple offer limits will not capture the underlying changes in costs faced by generators. However, the SEM Committee's proposed method of exceptions management is limited to physical factors. For instance, the Consultation Paper considers plant "required to run in OCGT mode" because of "a physical outage of the steam turbine within a CCGT train", "to run in a secondary fuel mode, or other circumstance not catered for within the limits calculation."[38] Freedom to breach the limit in "exceptional physical circumstances" would be subject to evidence-based review by the MMU.

The SEM Committee does not provide any criteria that justify restricting exceptions to physical factors. It will often be possible to operate a generator, but prohibitively expensive to do so because of an unforeseen rise in costs above its offer limit. In every such case, the regulatory authorities will have to consider making an exception, as it would not be efficient to force compliance with offer limits that lay below SRMC. However, it would be administratively burdensome to consider such exceptions case-by-case, since unforeseen rises in costs are inevitable and numerous. The proposal to rely on "exceptions management" to deal with unforeseen changes in conditions is therefore not practical.

It is also unclear how this procedure (or any equivalent) can be limited to "exceptional physical circumstances". Any large change in fuel prices (and other "commercial" or "economic" circumstances) would provide a reason for adjusting offer limits that was just as urgent and important for efficiency and competition. The Consultation Paper offers no grounds for excluding such reasons and no alternative means of accommodating such changes (other than the discretionary changes discussed in section 4.3.1 above). Section 4.3.4 of the Consultation Paper, on exceptions management, ends with a commitment to "further consultation", but that only serves to indicate how incomplete these proposals are.

In practice, the frequent changes in costs facing generators are not "exceptions", but a regular and expected feature of energy markets. To deal with them as exceptions (or discretionary changes) would be administratively burdensome for all concerned and highly inefficient. It would be administratively more efficient to allow the automatic adjustment of offer prices (and offer limits) whenever conditions change, instead of relying on the provision for exceptions. Given the likelihood and wide-ranging nature of unforeseen changes, it would be administratively even more efficient to avoid prescriptive rules altogether and instead to set out guiding principles that allow generators to adapt their offer prices to new conditions as they arise.

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38 SEM Committee (2016), *Offers in the I-SEM Balancing Market – Consultation Paper*, SEM-16-059, 7 October 2016, page 22.

4.3.4. Precedent for Framework

The SEM Committee cites the Italian electricity market as a precedent for Option 2:

> "Such a framework would not be the first time limits have been used in a European energy market. Offer Limits has been implemented for the calculation of start-up costs in the Italian Balancing Market. Generator offers are subject to limits calculated based on a unit price derived from the average value of the minimum offer prices over the previous year that were submitted by generation units with similar technology. The start-up offers cap calculation process is contained in chapter 4 of the Dispatching Regulations of the Italian Grid Code."[39]

The provisions to impose offer limits in the Italian bid code differ from the SEM Committee's proposals for Ireland in at least two important respects:

- Firstly, the Italian Dispatch Regulations only imposes a limit on offers for "Operational Set-Up and Start-Up" based on previously submitted offer prices.[40] Terna does not attempt to tie offers to start-up to any prescriptive list of costs, let alone the costs of fuel. The offer limits therefore cap prices only at levels that have previously been sufficient to cover costs. The SEM Committee's proposal, by contrast, seeks to calculate start-up, no-load and incremental/decremental costs from the bottom up and therefore replaces market participants' estimated costs with its own estimates, potentially omitting important cost items.
- Secondly, market participants do not face price caps for bids or offers on the DAM or on the balancing market as a whole: although market participants face a cap on offers for "Operational Set-Up and Start-Up", their energy offers are unrestricted. Accordingly, market participants may recover differences between allowed costs for Operational Set-Up and Start-Up and their underlying costs through higher energy prices.

As a result, the provisions in the Italian Grid Code provide no reliable precedent for the SEM Committee's proposal to set strict offer limits based on bottom-up estimates of costs for all the components of generators' three-part offers.

In other EU jurisdictions where regulators have wanted to control bidding behaviour by constrained generators, the relevant grid codes and licence conditions have deliberately stated high-level principles instead of imposing fixed offer limits. For instance, in Great Britain, the Department of Energy and Climate Change (DECC) introduced the Transmission Constraint Licence Condition (TCLC), which aimed to constrain market participants' bids in the balancing market. The TCLC proscribes two general forms of behaviour:[41]

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39 SEM Committee (2016), Offers in the I-SEM Balancing Market – Consultation Paper, SEM-16-059, 7 October 2016, page 22.

40 TERNA, Italian Dispatching Regulations, Paragraph 4.8.4.2.

41 DECC (2012), *Government Response to the consultation on the Transmission Constraint Licence Condition (TCLC)*, page 4.

- Making uneconomic dispatch decisions that create or exacerbate a transmission constraint (circumstance 1); and
- obtaining an excessive benefit from bids to reduce output during periods of export constraint (circumstance 2).

Ofgem's Guidance on how it intends to police the TCLC set out the high-level economic principles that it would apply in circumstance 2 ("excessive benefit"):

> "The following is a non-exhaustive list of indicators which Ofgem may consider when determining whether an excessive benefit has been obtained […]:
>
> **Avoidable costs** - Ofgem could compare bids accepted to manage export transmission constraints to estimates of avoidable costs. Avoidable costs can be defined as SRMC plus additional maintenance and ramping down costs, eg costs of going below the "Stable Export Limit". We would also expect to take account of opportunity costs and allow for reasonable profits to be earned. In the case of renewable generators, opportunity costs will include the price of ROCs and LECs.
>
> **Comparable generator benchmarks** - Accepted bids behind an export constraint could be compared with those charged by any comparable generators, on the other side of a constraint. Comparability could also take into account the differences between bids to, for example, turn down generation incrementally rather than reducing generation below the "Stable Export Limit" and having to shut down the plant completely.
>
> Other indicators from general market monitoring, such as historical bids during non-constrained periods and average GB-wide bids.
>
> If any of the above indicators suggest a potential breach, as set out in Chapter 3, Ofgem may write to the licensee concerned, giving them an opportunity to respond. If the licensee believes their pricing can be objectively justified, an explanation and supporting evidence should be submitted to Ofgem for assessment."[42] [emphasis added]

In setting out its high-level principles for enforcing the TCLC, Ofgem explicitly recognises the importance of the list of costs being "non-exhaustive", as well as the need for "reasonable profits".

Moreover, there are no *ex ante* restrictions on offer prices in balancing markets operating in other major European electricity markets (see further description in Box 4.2). Either bidding is unconstrained (except by competition) or else there is provision for detailed *ex post* investigations, as under the current arrangements in the SEM.

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42 Ofgem (2012), *Transmission Constraint Licence Condition Guidance*, paras 2.36-2.37.

Therefore, although the SEM Committee refers to a weakly related precedent in Italy, that supposed precedent is unlike its proposals for the I-SEM, which bear little resemblance to the price control systems operating in other major Western European balancing markets.

Box 4.2
Bidding Restrictions in Other Major European Markets

France's balancing market is governed by documents issued by the Réseau de Transport d'Électricité (RTE).[43] Generators have wide-ranging freedom to bid into the balancing market.[44] Balancing entities may submit a "start-up" offer if a balancing market instruction would require a generating unit to start up. RTE spreads this cost across the volume of each offer, when ordering and deciding how to call offers by their "effective price per MWh".[45]

The French balancing market rules contain procedures to be applied in the event of market power abuse. RTE publishes summary statistics on balancing offers, which show half-hourly average offer prices and maximum (and minimum) prices paid for upwards (and downwards) balancing offers. The Commission d'Accès au Marché (CAM), "regularly analyses price Journals and defines thresholds". When RTE observes a threshold being exceeded, it carries out a joint analysis of the case with a special committee of network users (the CURTE). "At the end of this phase, the thresholds will be re-evaluated".[46] Thus, any suspected abuse of market power in the balancing market is investigated on a case-by-case basis *ex post*, as under the current arrangements in the SEM.

Germany also operates a liberalised balancing market. Balancing energy is procured "through competitive bidding on a tender basis in the German control power market where a large number of suppliers (generators as well as consumers) participate".[47] The relevant TSO selects offers based on a merit order of capacity prices and settles on a pay-as-bid basis.[48] There are no rules limiting the prices the balancing entities can bid into the market.

In Spain, there are no defined limits or prescriptive bidding rules on balancing market offers, either in "tertiary control" (i.e. balancing market trades) or in the management of constrained plants. Generators may be fined if there is an "unjustified difference" between their offer prices for tertiary control and their offer prices in other markets (day-ahead, intra-day, etc).[49] However, applying this rule requires a detailed, case-by-case investigation *ex post* (and has not been invoked, as far as we are aware).

Bidding is also unconstrained (except by general competition policy) in the Netherlands.

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43 RTE (1 April 2016), Section 1 – Rules relative to the Programming, the Balancing Mechanism and Recovery of Balancing Charges. N.B. English translation is not definitive.

44 The French balancing market applies the pay-as-bid rule: "…the Offer Price will be used to establish the remuneration RTE pays to the Balancing Actor as compensation for an Offer Activation". RTE (1 April 2016), para 4.3.1.1.1

45 RTE (1 April 2016), paras 4.3.1.1.2 & 4.4.1.1

46 RTE (1 April 2016), para 4.8.1.6

47 http://www.amprion.net/en/control-energy

48 Consentec (27 February 2014), Description of load-frequency control concept and market for control reserves, page 21-22

49 Law 24/2013, Article 65.33 (available only in Spanish): "La manipulación del precio de los servicios de ajuste por parte de un agente del mercado mediante la realización de ofertas a precios excesivos, que resulten dispares de forma no justificada de los precios ofertados por el mismo en otros segmentos del mercado de producción."

4.3.5. Implementation

We understand that the TSO and I-SEM systems will be able to accommodate Option 2, so the main issue for implementation concerns the relative roles of licence conditions versus industry codes.

4.3.6. Conclusion

As we explained in section 2.4, discretionary regulation requires a framework of principles, to avoid creating unnecessary regulatory risk and jeopardising efficient competition. The UK Competition Commission set out these arguments in relation to the Market Abuse Licence Condition in 2001.[50] Defining a set of guiding principles in the licence would also enable better scrutiny of regulatory proposals before they take effect; the alternative is to wait until adverse effects become apparent before reversing a decision, a process that would be highly damaging to the interests of consumers and to the credibility of regulation. Therefore, we repeat here the conclusions we reached in relation to Option 1.

Whilst the desire to preserve flexibility is understandable, sound decision-making must rely on something more stable and objective than the subjective views of the regulatory authorities of the day to justify interventions in competition. The only practical means of overcoming this problem is to set out (and apply) clearly defined principles that allow market participants to anticipate when and how the regulatory authorities would intervene. Only then can market participants safely adopt efficient, competitive behaviour without fear of triggering sanctions. Only then can the quality of regulatory decisions be tested, before they take effect.

The need to set clearly defined principles (which we have described in comments on previous papers in this workstream[51]) applies both to the desire to extend controls and also to tightly defined rules that do not anticipate all possible future situations. It has important implications for the evaluation of both Option 1 ("Offer Principles") and Option 2 ("Offer Limits"), as we explain in section 4.4 below.

The SEM Committee's proposals for Option 2 would impose cost-based offer limits on groups of generators, for one quarter at a time. The SEM Committee does not explain how it will ensure that these offer limits will cover the short run marginal costs incurred by generators, raising the prospect that offer limits set too low will systematically deny cost recovery and discourage generation – with potentially catastrophic results for security of supply. The SEM Committee proposes some exceptions to the overarching approach, such as defining tighter limits for must-run generators, adjusting for certain physical conditions, and allowing for unforeseen rises in costs, but the frequency and importance of these exceptions merely illustrate the inadequacy of relying on simple rules in the first instance.

In practice, if the SEM Committee decides to impose offer limits, it will be necessary to ensure that every offer limit at least covers the SRMC of the generator concerned, and that

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[50] Competition Commission, *AES and British Energy: A report on references made under section 12 of the Electricity Act 1989*, CC No. 453, 31 January 2001.

[51] NERA (2016), *Review of the Capacity Remuneration Mechanism Local Issues Paper*, 22 September 2016, page 15.

the system adjusts or relaxes these rules whenever conditions change, according to pre-defined principles. These principles need to be entrenched in a licence condition, to provide the required degree of stability, and to allow proper scrutiny of proposals.

4.4. Appraisal of the Options

The appraisal of Options 1 and 2 is set out in a form that provides no basis for an objective choice.

First, the Consultation Paper quotes the "advantages" and "disadvantages" of each Option, but does not say what baseline or alternative is used to define them. The baseline may be no regulation, the current BCOP, or the other Option, or some combination of these alternatives. If each Option is appraised by reference to the other, then the advantages of one Option should be the same as the disadvantages of the other Option, and vice versa. However, the drafting suggests this is not so, in which case the appraisal is not even-handed.

Second, the Consultation Paper does not explain the criteria by which these advantages and disadvantages have been identified and appraised. The SEM Committee has set out a common set of appraisal criteria in previous documents, and their omission from the Consultation Paper is anomalous, especially since there is no alternative list of appraisal criteria. Given the lack of any such list, it is impossible to check whether the appraisal is complete for both Options. Indeed, it appears to be only partial.

Third, the difference between Option 1 and Option 2 is not as marked as the SEM Committee appears to believe.

The SEM Committee describes Option 1 as a principles-based approach similar in outline to the current BCOP. In practice, however, Option 1 consists of a prescriptive list of costs that may be included in offer prices, along with rules for defining those costs. These rules are so narrowly defined that they offer no guidance on how to incorporate new costs when circumstances change over time. Even in the short term, the proposals exclude potentially important categories of costs, such as costs which may be jointly incurred over multiple settlement periods and the opportunity costs of additional risks, for no good reason.

Option 2 consists of simplified rules which impose offer limits on generators according to calculations conducted by the SEM Committee on behalf of market participants. However, the SEM Committee implicitly acknowledges by providing for exceptions that it will need to ensure any offer limits remain in line with generators' SRMC. That requirement will in any case require the SEM Committee to set out and adopt clear principles for managing adjustments to the simplified rules, to minimise regulatory risk and to incentivise efficient, competitive behaviour.

Option 1 and Option 2 therefore both require the development of the same guiding principles to allow their adaptation over time. In the case of Option 2, the need to adapt rules over time applies not only to the definition of new cost items but also to the calculation itself. Option 2 does not in effect represent a different approach to defining eligible costs to be recovered in balancing market offers from Option 1, only a less complete one.

The only remaining difference between the Options lies in the method of implementation – whether the generators apply the rules to calculate their maximum offer prices, or the regulatory authorities carry out those calculations and publish the offer limits. No part of the appraisal focuses on that distinction between the processes under each Option. The appraisal does not therefore consider the real differences between the Options.

Fourth, there are severe problems with the individual elements of the appraisal set out in the Consultation Paper. We identify these problems in Appendix A.

The similarities between the Options, and the gaps in each of them, are not brought to light in the evaluation set out in the Consultation Paper, because it has not been properly conducted. The evaluation of the Options does not apply the criteria used in other ISEM papers, or any similar set, but only identifies vaguely articulated “advantages” and “disadvantages” relative to some nebulous (and possibly shifting) alternative. Therefore, the appraisal of Options 1 and 2 is not even-handed or complete. It provides no basis for favouring one Option over the other. It also provides no basis for deciding that either of these Options is better than a suitably adapted version of the current BCOP.

Appendix A. Review of Section 4.4: Appraisal of Options

In this appendix, we review the arguments set out in section 4.4 of the Consultation Paper, which purports to provide an assessment of Options 1 and 2, as set out in sections 4.2 and 4.3 respectively.

The assessment is structured as "a high-level overview of the advantages and disadvantages of each of the options". However, it does not define or apply a set of well-defined appraisal criteria and it does not define any alternative(s) against which these supposed advantages and disadvantages can be measured. It is therefore virtually impossible to check the completeness or consistency of the appraisal. In addition, the reasoning behind many of the supposed advantages and disadvantages contains major flaws, as we show in the sections that follow.

Our comments follow the order of points made in the Consultation Paper.

A.1. Option 1: Advantages

i. "Option 1 is based upon current arrangements, which have been in place for nearly a decade, and are well understood by all participants…Option 1 maintains a framework in which generators are familiar and understand." These statements present a false picture of Option 1, which differs from the current framework in several important respects. The current framework is set out in the generation licence, the Bidding Code of Practice (BCOP) and subsequent decisions on their interpretation. The licence requires cost-reflective bidding, sets out the relevant concept of cost (SRMC over a Trading Day), explains how to measure SRMC (the difference between total costs with, and total costs without, generating) and specifies the use of Opportunity Cost to value cost items.[52] The BCOP sets out guiding principles for the valuation of costs using the concept of Opportunity Cost. In comparison, Option 1 is considerably more prescriptive. The proposed text sets restrictive limits on some types of cost and specifically excludes other types of cost from offer prices (paragraph 8). The concepts and rules behind Option 1 would be set out entirely within a code, whereas the current framework is more stable because it specifies the basic cost concepts (SRMC, daily timeframe, OC) within each generation licence.

ii. "Delivery of Option 1 should be relatively straightforward and implementable…" This statement overlooks the major difficulties that will be caused by trying to set fixed rules that incorrectly define SRMC or Opportunity Cost, so as to disallow legitimate costs. In the first instance, the proposed rules will be disputed, as inconsistent with cost recovery and with incentives for efficient generation. If they subsequently enter into force, these rules will create operational problems that will eventually require the attention of the regulatory authorities (and lead to the restrictions being overturned in due course). Therefore, neither the delivery nor the application of Option 1 will be straightforward.

iii. "The principles regime will result in the fair and equal treatment of all offers." There is no reason to suspect that "fair and equal treatment of all offers" is a specific advantage of Option 1 over any realistic alternative. Under the governing legislation, the regulatory

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[52] Commission for Energy Regulation (2007), *Generic Generation Licence*, Section C, Condition 15, subsections 2-4.

authorities may not "discriminate unfairly between authorised persons" (i.e. between licensees) in any case. The Consultation Paper does not say that Option 2 is intrinsically discriminatory; if it did, that would be enough to invalidate Option 2. Also, as noted above, the regime defined by Option 1 is not a principles regime, since there are no stable principles set out in the Generation Licence, and several prescriptive rules disallowing specific types of cost (without good reason).

iv. *"All generators will be given equal access to competition specific information and will be able to see if their peers are complying with the rules set out. These characteristics contribute to the integrity of this segment of the market so that no unfair advantage (actual or perceived) is conferred to one generator over another."* This statement applies to the market as a whole, and not to the rules set out in Option 1. The Consultation Paper does not explain how this feature would be an advantage of Option 1 over Option 2 (or the current framework).

v. "From a theoretical perspective, requiring units tagged as non-energy in the Balancing Market to offer SRMC should lead to competitive outcomes." There are several problems with this statement. First, as discussed above, generators may not know which of their offers will be tagged as non-energy until after the fact, which may hinder competition in the energy market. Second, the competitive outcome sometimes requires prices – and offer prices – to depart from the costs of the producer in order to indicate shortage. Limiting prices to a generator's own SRMC does not always produce an efficient, and hence competitive, outcome. For instance, suppose the output of existing generator A has a variable cost (SRMC) that is higher than the sum of variable and avoidable fixed costs at generator B. ($SRMC_A > SRMC_B + F_B$, where F_B is the avoidable fixed cost of generator B.) If the rules prevent generator B from recovering its avoidable fixed costs, it will not enter the market and consumers will have no choice but to rely on the more expensive option of generator A. This possibility indicates why some flexibility in the application of any rules limiting offer prices is required to permit efficient and competitive outcomes.

"Finally, it should be noted that offer arrangements for generating units that receive a Reliability Option (RO) due to local issues will also require to be settled based on the methodology outlined under Option 1, even if Option 2 "Offer Limit" is the preferred option (i.e. an Option 2 only approach would potentially allow these units to make excess profits, where this potential issue would not occur under Option 1)." The Consultation Paper does not explain why Option 2 would allow any generator to make "excess profits", or what role is played by Reliability Options. "Excess profits" would seem to be impossible under any rule that limits offer prices to SRMC or less – and trying to use offer limits to claw back revenues from Reliability Options would destroy incentives for efficient operations and output. This comment therefore requires further explanation – or deletion.

A.2. Option 1: Disadvantages

i. "Under Option 1 there exists the risk that the framework will result in high prices at the perceived boundary at what might attract enforcement action from the RAs. Units could attempt to use the principles to effectively make offers as high as possible. For example, if a unit is must run in the market, under Option 1 there exists no incentive for the unit to innovate. However there does exist an incentive to submit offers as high as is possible under the framework. In this sense the framework may not create an environment in which *generators compete away profits."* This set of supposed disadvantages does not contain any coherent economic reasoning.

- The apparent lynch pin of the argument is that generator units would try to "make offers as high as possible". However, this statement says no more than that generators are profit-maximising. That is a condition of efficient competition and does not apply specifically to Option 1.
- As for the supposed lack of incentive to innovate, there is no reason why it should be more of a problem under Option 1 than under a system of offer limits that ties offer prices to the generator's actual costs (Option 2). Indeed, if the former were to allow prices to uncouple from costs, it would give generators an incentive to reduce their costs (as under price cap regulation). In contract, the latter would explicitly take away a generator's incentive to invest in lowering its SRMC, since the reduction in SRMC would be passed on to the market via a lower offer limit and the generator would be left to bear the fixed costs of the investment.
- If this comment is intended to argue that some problem lies in the flexibility offered by a (truly) principles-based regime, it should be noted that Option 1 applies fixed rules, not principles. Flexibility is only required to deal which genuine uncertainty of the future nature of costs and fixed rules do not deal with genuine uncertainty any more efficiently.

ii. "Historically, as discussed in Section 3.2, there has been many challenges in the SEM as to whether to include, and how to value, a number of cost items…. This has been extremely resource intensive for the RAs and affected participants, and at times has led to resources being diverted from other areas." The resolution of disputes merely helps to clarify interpretations of the rules and should not be regarded intrinsically as a sign of failure for the regime. Indeed, major disputes only arose when the regulatory authorities tried to disallow costs that were part of SRMC, and these disputes were eventually resolved in the generators' favour. One might conclude that the source of the problem was the poorly judged use of regulatory discretion, not the flexibility offered to generators by a principles-based regime.

In any case, setting fixed rules (offer limits and specific cost disallowances) will not reduce the number of resource intensive problems for the RAs and affected participants. If the RAs try to disallow legitimate components of SRMC, it does not matter whether they do so by setting rules or interpreting principles. The real problems caused by such decisions will be the same and they will require resolution – either before or after the real costs of such decisions become apparent. The RAs' diagnosis of the problem underlying disputes is therefore faulty, the RAs have wrongly identified the solutions to these problems, and the appraisal of the options is therefore misguided.

A.3. Option 2: Advantages

i. "Option 2 would incentivise generators to increase their units['] efficiency. By reducing the cost of dispatching their unit they will be able to avail of greater profits if they are must-run, and if they are in competition with other units this option should facilitate competition between units. This is because the unit will be able to offer up to the offer limit. The more the efficient the unit, the greater the amount of infra-marginal rent that the unit will be able to earn as its actual costs could be below this limit." The problem with this text should be apparent to any economist familiar with incentive regulation. If each generator's offer limit under Option 2 is tied to its own costs, and updated quarterly, then any reduction in the cost of generator will be passed on to the market via a lower offer limit and lower prices at the next quarter. That removes the incentive to increase efficiency. (The comment applies specifically to generators that are "must-run" and therefore "able to offer up to the offer limit." It may be that the comment is meant to apply only when offer limits are set for groups of similar generators, but that is not a necessary feature of Option 2 and no such assumption is stated here.) Thus, not only is this argument incorrect, as stated; it indicates that those carrying out the appraisal do fully not understand the options they are appraising, or else do not understand the economics of competition, regulation and incentives.

ii. "Compliance with price limits (Option 2) is more transparent and objective than compliance with principles open to interpretation and review by the MMU (Option 1)." This statement presumes that applying restrictive rules is more transparent than the interpretation of principles, but that is not necessarily the case. The current proposals disallow certain costs that have been included within SRMC up until now, for reasons that are non-transparent (arbitrary, selective, inconsistent). If the restrictive rules are not sustainable, because they set offer limits below SRMC, generators will have to find non-transparent ways to work around them or else the regulatory authorities will have to amend the code in a non-transparent manner (i.e. without recourse to stable guiding principles). The operation of such a regime may therefore be less transparent over the long run than a steady and consistent application of guiding principles. Given the arbitrary nature of some of the proposed rules, the basis for any decision to extend controls into the energy market also lacks transparency. (We note that this point compares Option 2 with Option 1, unlike advantage iv.)

iii. "Generator participants could also benefit from a 'level playing field' as there is less potential for ambiguity in the rules that govern the calculation of offers." Given the arbitrary and selective nature of the current proposals to disallow some elements of SRMC, they will affect different generators to differing degrees. Hence, there can be no talk of a "level playing field" among generators under Option 2.

iv. "From a regulatory perspective, the monitoring of Offer Limits compliance would be substantially less resource-intensive than the monitoring of compliance with a BCoP…." This argument is the converse of disadvantage iv of Option 1, so it is not a separate point and the same comments apply. In summary, setting reliable limits would be hugely resource intensive, as the process would have to deal with errors and the effects of under-recovery. (We note that this point compares Option 2 with the current BCOP, unlike advantage ii.)

A.4. Option 2: Disadvantages

i. "There will be a requirement to engage in a follow up consultation on the detail behind the calculation, form and publication of the first set of offer limits before go-live." This point is an admission that implementation of Option 2 will be "resource intensive" and that Option 2 cannot be described as transparent, due to the lack of detail at this stage. In the absence of any stable guiding principles, the decisions emerging from these consultations may be arbitrary and deny cost recovery in ways that create problems for the regulatory authorities in the future.

ii. [A] "There is also the potential that the introduction of offer limits will lead to a loss of efficiency and higher costs because units may simply offer at the outer limit of what is deemed acceptable, leading to a potentially suboptimal solution." This would be a serious drawback, if it were likely. However, since the current proposal would tightly restrict the costs allowed to be included in offer prices, and exclude some costs that are and always have been counted as a component of SRMC, it seems unlikely that offer limits would be deemed to be too high by any meaningful standard. However, this point is really a potential flaw in any form of regulation and so it is not clear why it should be a disadvantage attributed to Option 2. A more likely outcome of Option 2 is the suppression of offer prices below SRMC, leading to suboptimal solutions because some generators exit the market to avoid making losses.

[B] "Offer limits must be set at the level of the least efficient unit, hence generators have an incentive to innovate and increase their efficiency. However, customers may not benefit from the reduction in costs as generators could simply continue to offer up to the offer limit." This potential problem is limited to the case where offer limits are set for groups of (ideally, similar) generators. Given that assumption, it negates the effect set out in "advantage i" of Option 2, so either or both should be omitted.

[C] "There are also a number of questions as to how quickly the change in limits could also be calculated in response to sudden market changes." This point directly contradicts the supposed ease of implementation assumed by advantage iv. It actually confirms our comment above, that trying to set fixed rules in changing circumstances is no less resource intensive – and potential more obstructive – than defining principles that allow automatic adaptation to new situations.

iii. "The framework that underpins Option 2 would also be based on the principles set out in Option 1. So there exists the potential for disagreement in circumstances where these principles are interpreted by the SEM Committee so as to set limits that generating units deem unacceptable." This point confirms that argument that we have made throughout our report, namely that setting fixed rules will not be any less of a regulatory burden than interpreting a principles-based regime, because the rules will have to be continually adapted to changing circumstances. Ignoring the changes will only cause under-recovery of costs and disincentivisation of efficient output, leading to ever more serious problems for the regulatory authorities to resolve. This point confirms that the whole Consultation Paper is based on a myth, i.e. that fixed rules are easier to implement than a principles-based regime.

Appendix B. Option 1 – Balancing Market Offer Principles Code of Practice

Certain sections of the proposed "offer principles cost of practice" set out in Annex A of the Consultation Paper merit comment. The following comments identify the paragraphs containing the most serious flaws in the current draft.

6. For the purposes of the previous paragraph, SRMC equals the incremental change in the costs of operating the generation set or unit during an Imbalance Settlement Period incurred as a result of either increasing generation output by one additional unit (MWh) of energy or reducing generation output by that amount (the resulting output level being referred to as the Relevant Output Level), [assuming the generation set or unit is already online and generating at a given output level at or above its [Minimum Stable Capacity]]

7A. For a given level of output, the SRMC is to be calculated as:

> **a. the [total of those eligible costs listed in paragraphs [14] to [21] below] attributable to the generation set or unit during an Imbalance Settlement Period at the Relevant Output Level;**
>
> **minus**
>
> **b. the [total of those eligible costs] attributable to that generation set or unit during that Imbalance Settlement Period at an output level which is 1MWh lower than the Relevant Output Level.**

It is impractical to limit the measurement of short run marginal costs to increments of one MWh of energy, since some balancing market actions result in the production of more than one MWh, linked together technically by physical operating constraints and/or economically by joint costs. In such cases, it does not make sense to attribute all the costs of production to the first additional MWh and none to subsequent MWh. (That feature of costs would lead to excessive offer prices under the rules proposed in the Consultation Paper.)

Instead, some costs of increasing output must be counted as SRMC and spread over all the units of energy produced by a single "Balancing Market Action", i.e. over the output likely to be produced in response to a single instruction to change the level of generation. The definition of SRMC must therefore be redrafted to refer to the change in output and costs caused by a single Balancing Market Action. It must be left to the generator concerned to specify the size of a typical Balancing Market Action for its plant.

In general, it will be difficult to attribute costs directly to individual MWh of output, if the change in output affects costs over a wide time period (e.g. by shifting start-up costs from one period to another). The only practical way to measure the marginal costs of a change in output is to compare total costs with and without the change in output. SRMC should therefore be defined by adapting the definition used in the Generator Licence Condition on Cost-Reflective Bidding in the Single Electricity Market so that it identifies the change in costs over periods other than a Trading Day and relevant to the Balancing Market Action:

For the purposes of [setting cost-reflective prices], the Short Run Marginal Cost related to a generation unit in respect of a ~~Trading Day~~ [Balancing Market Action] is to be calculated [for each half-hour ISP] as:

(a) the total costs that would be attributable to the ownership, operation and maintenance of that generation unit during a Trading Day if the generation unit were operating to generate electricity during that day [including the Balancing Market Action starting in that ISP];

minus

(b) the total costs that would be attributable to the ownership, operation and maintenance of that generation unit during that Trading Day if the generation unit ~~was not~~were operating to generate electricity during that day [excluding the Balancing Market Action starting in that ISP, but in an otherwise identical pattern],

the result of which calculation may be either a negative or a positive number[, and may be calculated either for each ISP separately or for representative ISPs over the course of a Trading Day].

8. Each of the items that are listed as eligible costs in paragraphs [14] to [21] below shall be included in the calculation of SRMC. *Any items not listed in those paragraphs, including but not limited to, potential, future forgone revenues or potential future penalties shall be excluded from that calculation*. Costs associated with starting up the generation set or unit and no load costs shall also be excluded from that calculation.

10. Each of the items that are listed as eligible cost items in paragraphs [22] to [23] below shall be included in the calculation of the start-up cost component of Commercial Offer Data. *Any items not listed in those paragraphs shall be excluded from the calculation of that component.*

and

12. Each of the items that are listed as eligible cost items in paragraph [24] below shall be included in the calculation of the no load cost component of Commercial Offer Data. *Any items not listed in those paragraphs shall be excluded from the calculation of that component.*

The provisions that exclude any costs not mentioned in the (extremely restrictive) list set out in later paragraphs are unduly inflexible. They inject unnecessary regulatory risk by removing any assurance that new types of cost, or costs that the regulatory authorities fail to anticipate, can be included in future offer prices. These provisions will render the controls difficult to apply, or simply unworkable. In each case, the italicised sentences should be deleted or replaced with a provision for including unforeseen costs in offer prices, before they become a problem for incentives and efficient operations.

15. Incremental fuel costs shall be calculated in accordance with paragraph 16, using actual fuel prices.

The proposal provides no definition of "actual fuel prices" and there is unlikely to be any practical definition of this term that is relevant to the calculation of SRMC. Efficient decisions depend on opportunity costs. The fuel prices actually paid by a generator in the past are not relevant to the calculation of today's opportunity costs. The opportunity cost of replacement fuel may be based on current spot prices or currently quoted forward market prices, but neither concept is best described as an "actual fuel price", not least since the generator would not actually pay it if it did not run, and because the current forward price may not be the actual spot price or opportunity cost on the day. In any case, paragraph 16 implies the use of an index, i.e. not the actual price paid, so this whole paragraph seems to be redundant, as well as contradictory or meaningless.

18. Non-fuel variable operating costs that vary with the level of output, including consumables and materials, shall be included in the price component of Commercial Offer Data. Long-term maintenance expenses shall not be included.

This paragraph simply overlooks the concept of maintenance expenses that vary with the level of output. Such expenses may be short-term (e.g. the wear-and-tear caused by running machinery) or long-term (e.g. the cost of major maintenance outages that are required after accumulating a certain output or number of hours of operation (like a car service required every 6,000 miles), rather than merely after a certain time period. The final sentence therefore contradicts the first sentence and should be deleted. If there is any need for clarification, the exclusion should relate to maintenance expenses that are "related to time rather than operation of the plant".

20. Incremental emission costs consist of the value of CO2 credits, issued under the Emissions Trading Scheme established by the European Commission, that are required to cover the CO2 emissions resulting from generating an incremental unit of energy (1 MWh).

If referring specifically to the EU Emissions Trading Scheme, the term "CO2 credits" is out of date. The correct term is EU Emissions Allowances. However, given the principle that the cost of emitting CO2 is an incremental cost of emitting energy, it would be short-sighted (and risky, given the history of the Carbon Revenue Levy) to omit reference to any charges, taxes or other incremental costs of output arising from the emission of CO2 or other pollutants, under future environmental legislation.

21.b.: Value of CO2 credits (€ per tonne of CO2). This will be the same across the [Single Electricity Market], equal to the Emissions Trading Scheme value.

This statement has already been invalidated by the decision of the UK government to apply a minimum price to generators within Great Britain. It would be short-sighted (and risky, given the history of the Carbon Revenue Levy) to omit reference to possible alternative charges applying within the area of the I-SEM.

22.c. Variable operating costs. Non-fuel variable operating costs should cover those directly incurred as a result of a set or unit start-up, including consumables and materials. Licensees shall justify any such costs and obtain the Regulatory Authority's approval before such costs are included in start-up costs. Long-term maintenance expenses shall not be included in start-up costs.

There is no reason to limit variable operating costs to those incurred as a result of a start-up (and to be included in start-up costs), as opposed to those arising from continued operation (and to be included in no-load costs) or actual output (to be included in incremental and decremental offer prices). As discussed above, the proposed treatment of maintenance expenses is inconsistent with the technical nature of generator operation. *Variable* operating costs of maintenance are, by definition, an element of SRMC.

24. The no load cost shall include, as the starting point, the total fuel cost required to maintain zero net output at synchronous generator speed.

The meaning of "as a starting point" is unclear; it suggests that non-fuel costs may be included, but paragraph 12 rules out the inclusion of any cost items not explicitly mentioned. There is no reason to exclude non-fuel costs related to hours of running, so they should be mentioned here (or else paragraph 12 must be amended).

29.b. [Definition of Opportunity Cost:] where no recognised and generally accessible trading market exists in the relevant cost item the OC of that item should reflect the costs which would be incurred by the Licensee in replacing that cost item, providing evidence of a minimum of three bilateral offers for the cost item.

The requirement to provide three bilateral offers is not included in the current BCOP, for the simple reason that it would not be practical. For items where "no recognised and generally accessible trading market exists", generators will not be able to find such offers quickly and easily, since such offers would constitute a "recognised and generally accessible trading market". Generators may have offers for some costs arising from their own operations. However, they will not have relevant offers for some costs, and any offers for costs they incur infrequently will be out-of-date as a measure of today's opportunity costs. The requirement for such evidence in all cases is therefore unduly restrictive; the code should at least make provision for the use of evidence that is equally reliable.

32. OCs may be calculated using monthly futures prices of fuel and electricity, as forecasts of fuel and electricity costs, which, together with unit characteristics and SRMC-based offers, can be used to calculate the expected margins for a set or unit during a defined future period.

The requirement to provide three bilateral offers is not included in the current BCOP, for the simple reason that it is unlikely to be relevant. Elsewhere, the regulatory authorities have defined the SRMC of balancing market actions over much shorter periods (down to an individual half-hour), so monthly fuel prices will not represent the SRMC or opportunity cost of burning fuel to generate in the Balancing Market. This provision is therefore inconsistent with other parts of the code and should be deleted.

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NERA
ECONOMIC CONSULTING

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com