



**Response by Energia to SEM Committee
Consultation Paper SEM-15-094**

I-SEM Market Power Mitigation Consultation Paper

18 January 2016

1. Introduction and Overview

This document sets out Energia's comments in response to the Consultation Paper on I-SEM Market Power Mitigation dated 20 November 2015¹, including answers to the questions posed within that paper.

In support of this response, we have submitted the slides used by Graham Shuttleworth (the "NERA Presentation") at our meeting with the Regulatory Authorities (RAs) in Belfast on 15 December 2015.

Energia would be happy to answer any questions about this response, should the RAs require any clarification of our comments. Energia's point of contact in relation to this workstream is Kevin Hannafin (khannafin@vpower.ie, +44-(0)-7787-136820).

The structure of this document is as follows:

- The remainder of this section 1 provides an overview of our key conclusions and the legal obligations and economic principles that should underpin the RAs' analysis of Market Power Mitigation (MPM) measures;
- Section 2 reviews the current MPM measures in the SEM;
- Section 3 discusses different metrics for identifying candidates for market power mitigation measures for any MPM measures adopted under I-SEM;
- Section 4 describes the problems that may arise in applying strict and formulaic controls to constrain bids to an estimate of Short Run Marginal Cost (SRMC);
- Section 5 sets out the specific problems that pricing at SRMC may cause for generation operating behind transmission constraints;
- Section 6 describes our concerns relating to market power in forward markets; and
- Section 7 links the questions set out in the Consultation Paper with the corresponding sections of this document, for ease of reference.

1.1. Main Conclusions

Many of the proposals in this Consultation Paper are not appropriate remedies for the problems they are supposed to address. In some cases, they are neither practical nor economically sound. In other cases, they will face significant difficulty complying with the legal framework that governs the RAs' activities.

Only a principles-based approach to mitigating market power in I-SEM holds any prospect of promoting competition and of being practical and compliant with applicable legal requirements.

Energia supports Option 4 as proposed for the DA and ID markets and also consider this the only appropriate MPM measure for the Balancing Market. A

¹ Consultation Paper "I-SEM Market Power Mitigation", SEM-15-094, 20 November 2015.

requirement for transparency applies to this and all other principles-based options, and hence there is a need for some published guidelines on what constitutes prohibited behaviour.

The targeted and effective mitigation of the dominant entity's market power across all I-SEM and DS3 markets must be the primary focus of the market power mitigation strategy to help develop the conditions required to support effective competition under I-SEM and DS3, and this should extend to the forward market.

For convenience, we list our key findings and conclusions below.

- **Identification of candidates for market power mitigation:** Both the HHI and RSI indicate that ESB's market power will persist in peak/stress hours until at least 2024. These results indicate unequivocally that ESB will be a candidate for targeted MPM measures, to ensure that it does not distort competition in any relevant market, by raising prices, by withholding supply, or by suppressing prices.
- The dominant or pivotal position of ESB will translate into additional market power in secondary markets for capacity.
- Design of effective structural filters will require further work on Conduct and Performance given the Consultation paper's focus on structural measures.
- **SRMC pricing:** Prescriptive rules on SRMC pricing will not promote efficient competition, are wholly inconsistent with applicable legal requirements including constitutionally protected rights of property, and will deny consumers the services they require. Prescriptive rules on SRMC pricing are accordingly not an option that is open to the RAs.
- A *practical* and *effective* MPM measure, that minimises both Type 1 errors and Type 2 errors, must couch restrictions on bidding or pricing in terms of principles (similar to, or adapted from, those in the BCoP). That applies as much to the BM as to any other market in the I-SEM.
- The interpretation of any future bidding principles must be *flexible* enough to deal with all future cases and objective or *transparent* enough to give market participants clarity over what competitive behaviour is allowed, as well as what abuses are prohibited.
- **SRMC pricing for transmission constrained generators:** The same conclusions on MPM measures apply to generators in transmission-constrained areas as to those in the wider market.
- In particular, prescribed rules for SRMC pricing are not only wholly inconsistent with applicable legal requirements but in addition run the significant risk of denying consumers access to the support that generators provide to the network in transmission-constrained areas.
- **Forward Market:** Market power and competition problems arising in forward markets may well fall outside the scope of the financial regulatory authorities.
- Given these considerations, the MPM Workstream will not have completed its task properly, and cannot safely hand over all consideration of forward

markets to the F&L Workstream, until it is agreed formally that the F&L Workstream will cover all matters relating to liquidity in forward markets, including matters of market power delegated from the MPM Workstream.

- **Vertical Ring Fencing:** The RAs should impose ring-fencing obligations based on an assessment of appropriate metrics – e.g. market shares – rather than based on the status of a particular company as a “legacy incumbent”.
- However based on all current evidence it would be absurd to regard a reform of the electricity market rules as sufficient justification for removing the obligation to adopt vertical ring-fencing on ESB. It is therefore appropriate that a targeted obligation to adopt vertical ring-fencing continues to apply to ESB at least. It would require novel and compelling arguments to justify removing this obligation and none has been advanced.

Whenever competition is feasible, as a matter of sound economics, letting competition set prices is preferable to regulating prices. This is consistent with the statement in the Consultation Paper that minimising interference with the market is an objective of the RAs.² This objective is not just preferable from an economic point of view, but is also required as a matter of Irish administrative and constitutional law.

The promotion of effective competition is a key objective of the Third Energy Package and is reflected in the statutory duties and functions of the CER³. In this context, promoting competition means fostering the *competitive process* rather than imposing someone’s view of the “competitive” *outcome*. In choosing between different options, the CER must have regard to what is the most effective, least intrusive and proportionate measure which will allow competition to develop and generators to continue to generate and invest. It must also have regard to the property rights of generators, among which is Energia. In this regard the only way that Energia and its shareholders may exercise, and enjoy its property rights as a generator, is through participation in the electricity markets. It is therefore essential that the electricity markets are designed to respect these property rights, in accordance with constitutional requirements.

Furthermore, in doing so, the CER must have regard to the requirements of section 5 of the Competition Act 2002 to 2014 as well as Article 102 and Article 106 of the Treaty on the Functioning of the European Union having regard to the position of market power enjoyed in electricity markets by a State-owned entity, namely the ESB.

In this regard, while we have a number of concerns, as set out in this response about the arguments used in the Consultation Paper, we are particularly concerned about the way in which the Consultation Paper brushes

² SEM-15-094, paragraph 8.3.1.

³ We note that UREGNI, as the electricity regulator for Northern Ireland, has identical functions and duties as regards matters relevant to the Third Energy Package and the Single Electricity Market and its actions as an administrative authority is subject to similar general legal principles.

aside concerns about market power in the forward market. In June 2015, we submitted a report by NERA Economic Consulting (NERA) which explained how the particular status of ESB “reduces its requirement to manage risk by trading forward contracts with entities outside the ESB group of companies”⁴ and how, without these contracts, independent generators and suppliers “will not be able to compete effectively in physical markets for generation and retail supply”.⁵ Section 6.4 of this response summarises the evidence provided by Baringa in April 2014. Since then, the situation has only deteriorated, as can be verified by updating Baringa’s analysis. The Consultation Paper does not address any of these concerns, our presentation therefore concluded:

“Failure to properly address issues in the forward contract market will result in substantial risk management issues for participants and will significantly undermine the conditions to support and promote retail competition, increasing costs for consumers.

It is therefore essential that these issues are formally acknowledged by the market power workstream and properly addressed by the forward and liquidity workstream.”

This is only one of our concerns, but we bring it to the attention of the RAs here, because it highlights a concern that is relevant to the whole I-SEM process.

Below, we have organised our comments on the proposals for market power mitigation around five topics, but we begin by discussing out the legal requirements that limit the range of potential outcomes and the key principles that are relevant to future decisions in the Market Power Mitigation (MPM) Workstream. These legal requirements and key principles are reflected in our comments on the proposals and in our answers to the consultation questions.

1.2. Legal Requirements

1.2.1. Governing legal provisions

Reference is made below to specific duties and obligations of the CER. We note that UREGNI, as the electricity regulator for Northern Ireland, has identical functions and duties as regards matters relevant to the Third Energy Package and the Single Electricity Market and its actions as an administrative authority is subject to similar general legal principles, and this section should be read accordingly.

Key legal requirements include, at the very least, the following provisions:

- **The objectives pursued under the Third Energy Package:** the measures adopted by the RAS must be consistent with the Third Energy Package and its objectives, namely, as regards electricity, the implementation of the internal market in electricity aims so as to deliver real choice for all consumers of the European Union and more cross-border trade, and achieve efficiency gains, competitive prices and a higher standard of service, and contribute to security of supply and sustainability. This means that facilitating cross-border trade must be

⁴ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, page13.

⁵ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, page 13.

done in such a way that it leads to further competition and the supply of electricity at the most competitive price.⁶

- **Directive 2005/89/EC** of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment which requires Member States to ensure a high level of security of electricity supply by taking the necessary measures to facilitate a stable investment climate and by defining the roles and responsibilities of competent authorities, including regulatory authorities where relevant, and all relevant market actors and publishing information thereon. In doing so, Member States must take account of, inter alia, the importance of a transparent and stable regulatory framework and ensure that any measures adopted are non-discriminatory and do not place an unreasonable burden on the market actors, including market entrants and companies with small market shares. Under Article 5 of the Directive, Member States must take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity, and in particular, must, without prejudice to the particular requirements of small isolated systems, encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption.
- **The functions and duties of the CER under section 9 of the Electricity Regulation Act 1999**, which reflect the objective of fostering effective and sustainable competition. In particular, under section 9(1), the CER is responsible for ensuring, among other things, effective competition and the efficient functioning of the electricity markets and this requires the CER to monitor, among others “*the level of competition and transparency in respect of wholesale prices...*”
- **Section 9(4)(a) of the Electricity Regulation Act** that requires both the Minister and the CER, in carrying out the statutory functions in Article 37 of the Electricity Market Directive, to have regard to the need, among others: (i) to promote competition in the generation and supply of electricity; (ii) to secure that all reasonable demands by final customers of electricity for electricity are satisfied and (iii) to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake.
- **General principles of administrative and constitutional law:** public authorities such as the CER must act in a manner that is (1) consistent with the legal framework within which they operate and (2) reasonable.
- It is also a general principle of European law that measures adopted by a public authority should be proportionate, that is, any measure must be both *suitable* and *necessary* to achieve the aim pursued, so public authorities must choose the least onerous way of achieving that aim. The proportionality requirement also applies under Irish constitutional law.

⁶ Recital 8 of the Electricity Directive, Directive 2009/72/EC.

- Where a measure affects a constitutionally protected right – such as the right to property or the right to earn one's livelihood, the implementing authority is under the obligation to ensure (a) that the measure is rationally connected to the objective and is not arbitrary, unfair or based on irrational considerations; (b) that the measure impairs the right as little as possible and (c) that the measure's effects on the right are proportional to the objective⁷.
- Measures that are under consideration by the RAs, including in particular prescriptive rules for SRMC pricing, directly and significantly affects the property rights of existing generators such as Energia and their shareholders. As participation in the market designed by the RAs is the only means available to existing generators such as Energia and its shareholders to exercise their property rights and right to earn a livelihood, it is incumbent upon the RAs, and essential, that the market design respects such property rights and allows a generator to recover its costs – any design which does not allow a generator to recover its costs, as would be the case where prescriptive bidding rules be adopted - would amount to a form of unconstitutional expropriation.
- **European State Aid law requirements:** The I-SEM must be designed so that, in accordance with European law, including in particular State aid law, State intervention in the market is avoided to the maximum extent possible. The European Commission has made clear that State intervention through State resources for the purpose of ensuring sufficient capacity will not be deemed to be permissible State aid unless “regulatory failures such as wholesale ... price regulation” have first been addressed and removed.⁸ We believe that the highly prescriptive bidding rules, such as those proposed under Options 1-3 for the ex-ante and BM markets will lead to regulatory failures and unnecessary State intervention through State resources that is inconsistent with the rules laid down by the European Commission as conditions to permissible aid.
- **The requirements of section 5 of the Competition Act 2002 to 2014 as well as Article 102 and Article 106 of the Treaty on the Functioning of the European Union having regard to the position of market power enjoyed in electricity markets by a State-owned entity, namely the ESB:** In this regard, measures which do not properly distinguish between the position of (1) undertakings, in particular public undertakings, in a position of dominance on the market and (2) others would lead to unlawful discrimination. Similarly measures which do not recognise the special position of public undertakings and the possible differences in their incentives and consequent market behaviour would be incompatible with Articles 102 and 106 TFEU and Article 4 of the Treaty on the European Union.

⁷ *Heaney v Ireland*, [1994] 3 I.R. 593.

⁸ European Commission, Communication of 5 November 2013, “Delivering the internal electricity market and making the most of public intervention”, C(2013) 7243 final.

These legal requirements apply to all and any measure that the RAs adopt or cause to be adopted in respect of I-SEM but also, importantly, to the *package* of regulatory measures which together will make the I-SEM market design – including among others the Capacity Remuneration Mechanism, DS3 System Services, Administered Scarcity Pricing, energy market bidding restrictions, and other Market Power Mitigation measures. Key in this respect is the requirement that measures, individually and taken together, allow generators to finance their activities, this package of regulatory measures must provide generators with an opportunity to cover their costs. In this regard, it is possible that the options preferred by the RAs in each of the streams for the I-SEM Design, because on their face they promote the objectives being pursued, are not together an optimal or indeed an acceptable or lawful combination because together they produce a result that is inconsistent with the Third Energy Package and the Electricity Security of Supply Directive and contrary to the requirement that generators should be able to finance their activities and allowed enjoyment of their property rights. Section 1.2.2 below sets out by way of example a combination of measures which would not allow generators to finance their activities in the long term and as a result would be contrary to legal requirements and detrimental to competition and security of supply.

1.2.2. Implications for market design

We are particularly concerned that piecemeal consideration of individual measures might produce a combination like the following one:

- a) Low prices in the Capacity Remuneration Mechanism, caused by weak incentives to provide new capacity, and/or inadequate checks to ensure that offers of demand-side response are backed by the willingness and ability to reduce demand on request;
- b) Insufficient DS3 System Service revenues, caused by the imposition of inappropriate cost based tariffs or bidding restrictions, or a design which does not adequately reflect locational value;
- c) High Administered Scarcity Prices, imposing high penalties on existing capacity holders in the event of a shortfall;
- d) Illiquid secondary market for capacity, due to a lack of any obligation on ESB to make capacity available to others at a reasonable price;
- e) Low, non-commercial offer prices submitted by a dominant, state-owned company like ESB as a result of insufficient properly targeted MPM measures; and
- f) Overly prescriptive formulae that prevent generators from offering at all times prices which are sufficient to recover their costs.

Such a combination would expose generators to the risk of high costs if their capacity was unavailable during a shortage, whilst denying them the opportunity to earn the revenue needed to recoup their total costs. It would discourage both the construction of new generation capacity and the maintenance of existing generation capacity (including generation capacity

behind a transmission constraint). It would therefore threaten security of supply.

For this consultation on MPM measures, prescriptive formulae for SRMC pricing and issues arising from State-owned ESB's dominance (items d), e) and f) above) are the most relevant and we return to them in later sections. However, in the light of certain comments within the Consultation Paper, we wish to stress the importance of avoiding item f) – prescriptive formulae for offer prices – as part of any market design.

The Consultation Paper suggests the RAs may have the impression that US markets use prescriptive formulae to tie offer prices to SRMC. Closer inspection reveals that (1) that impression is not correct and (2) other rules offer sources of revenue that may not be available within the I-SEM. For example, Option 2a, described in paragraphs 8.7.9-12 of the Consultation Paper, bears some resemblance to the automatic price capping rules of the PJM market. However, the Consultation Paper does not mention the following features of the PJM rules:

- In the PJM, the offer price caps are subject to a wide margin over “incremental cost”, to allow for errors and for non-specific fixed costs.
 - For the generators in the PJM whose prices are capped most frequently (e.g. generators within small transmission-constrained market areas), the price cap rule allows a margin of “the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus \$40 per megawatt-hour”.⁹
 - This margin is applied to generators whose revenues would not otherwise cover certain costs.¹⁰
- In the PJM, capacity prices are regional, so that capacity within a small transmission-constrained market area receives a high capacity payment, even if there is a global surplus of capacity.
- In the PJM, capacity offer prices submitted to capacity auctions are subject to minimum floor offer prices, equal to a percentage of the “Net Cost of New Entry”.¹¹

⁹ Schedule 1, Section 6.4, Offer Price Caps, rule 6.4.2.(a)(iii) of the PJM Operating Agreement, which can be found at: <http://www.pjm.com/documents/agreements.aspx>

¹⁰ Schedule 1, Section 6.4, Offer Price Caps, rule 6.4.2(b) of the PJM market Operating Agreement.

¹¹ A guide issued by the PJM mentions a minimum offer price equal to 90% and 70% of CONE depending on circumstances, for plant whose offer price is capped most frequently. See <https://www.pjm.com/~media/committees-groups/committees/mrc/20121004/20121004-mopr-exception-process-education.ashx>. This guide refers to section 5.14(h) of Attachment DD to PJM’s Open Access Transmission Tariff (OATT). Rule 5.14.h)(3) of the current OATT states that “The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry [CONE] for the relevant generator type and location, as determined hereunder” and specifies a CONE for “combustion turbines”, “combined cycle turbines” and “integrated gasification combined cycle generators” for each of four market areas. The OATT, a document of nearly 3,000 pages, can currently be found at: <http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf>

This example shows how tight regulation of offer prices would be wholly inconsistent with applicable legal and regulatory requirements and the development of a competitive market.

Whenever competition is feasible, as a matter of sound economics, letting competition set prices is preferable to regulating prices. This in fact follows from the objective of the RAs stated in the Consultation Paper to “interfere with the operation of the market to the minimum extent necessary”.¹² Indeed, limiting interference in the market is not just preferable from an economic point of view. Having regard to the implications of the proposed measure on the generators’ cost recovery and therefore on their property rights and their rights to earn a livelihood, it is also required as a matter of Irish administrative and constitutional law. In this context, limiting interference means seeking to promote competition, i.e.: fostering the *competitive process* rather than imposing an *outcome* that reflects one view of what is “competitive”.

The promotion of effective competition is a key objective of the Third Energy Package and is reflected in the statutory duties and functions of the CER. The RAs may believe that each of the options being explored allow cross-border trade and promote effective competition to a degree. However, in making a choice between the options identified, the CER must have regard to what is the most effective, least intrusive and proportionate measure which will allow competition to develop and generators to continue to generate and invest. As we explain in further detail below, in sections 4 and 5, the prescriptive bidding rules being considered by the RAs are wholly inconsistent with applicable legal requirements including constitutionally protected property rights, ignore relevant principles laid down in competition law including European competition law and will not allow the development of competitive electricity markets.

1.3. Key Principles

The Consultation Paper lists five key principles to be used “as the basis for assessing various market power mitigation policies”.¹³ These key principles encompass useful decision-making criteria, but they are subject to a wide range of possible interpretations. To provide a practical guide to decision-making, these key principles (para 8.3.1) must be considered in conjunction with the legal requirements arising from compliance with the statutory duties of the RAs and European law and Irish constitutional and administrative law. When applying these principles, it will also be necessary to avoid the two types of error also set out in section 8.3 of the Consultation Paper (para 8.3.3):

- “False positive” or over-mitigation (“Type 1 error”), i.e. false identification of a competitive behaviour as an exercise of market power.
- “False negative” or under-mitigation (“Type 2 error”), i.e. the failure to identify market power abuse when it exists.

¹² SEM-15-094, paragraph 8.3.1.

¹³ SEM-15-094, paragraph 8.3.1.

The “Type 1 error” and “Type 2 error” can be used to measure the effectiveness of MPM measures and their impact on competition. They are explained in paragraphs 8.3.5 and 8.3.6 of the Consultation Paper, but they are not mentioned anywhere else in the document, which is unfortunate. They provide useful guidance for making choices consistent with the legal principles above and shed light on the interpretation of the key principles set out in the Consultation Paper.¹⁴

Below, we explain how legal requirements and these error types interact with the interpretation of the key principles.

- **Effective:** The Consultation Paper defines effectiveness in terms of “mitigating the potential market power conduct (behaviour) or outcome (market performance)”. It therefore recognises that MPM measures should not fail to identify abuse, which would be a Type 2 error. However, an “effective” measure is also one that does not hinder competitive behaviour, which would be a Type 1 error.
- **Targeted:** MPM measures should obviously constrain dominant players, to avoid Type 2 errors. To avoid Type 1 errors, MPM measures should not impose a major compliance burden or otherwise hinder potential competitors. The Consultation Paper recognises the need to “limit the impact on the commercial incentives of market participants”. It also says that MPM measures should allow “a reasonable return on new investments in order to encourage competition to emerge and to signal the need for investment”. (Of course, this signal will only be efficient if existing investments have the same opportunity to earn a reasonable return.) In the report of 18 June 2015, NERA explained that “There is a fine line between protecting competition and stifling competitive behaviour”¹⁵ and that “the principal deciding factor behind which mechanism to adopt should be the effect on the ability of competition to secure an economically efficient outcome. In seeking to prevent the abuse of market power, remedies run the risk of distorting competitive behaviour by not sending efficient signals to market participants on where and when to increase output, schedule outages, enter or exit. Accordingly, the remedies should be targeted at objectively identified problems, to minimise their adverse effects on competition”.¹⁶ In a competitive market, signalling the need for investment will sometimes mean allowing *existing* providers to set prices that provide a reasonable return on *new* investment. In such cases, it would be a Type 1 error to cap prices at a lower level (i.e. to impose a regulated prescription of SRMC), preventing generators from financing their activities and hindering the competitive process.
- **Flexible:** We agree that rules must be designed flexibly so as to capture new forms of abuse (and to avoid Type 2 errors), but flexibility means that the rules must also permit all forms of competition

¹⁴ The following text is an expansion of points made in the NERA Presentation of 15 December 2015, on slide 4.

¹⁵ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 3.4, page 9.

¹⁶ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, page 14.

behaviour, including innovative ones (to avoid Type 1 errors). The latter principle helps to explain why prescriptive formulae would not provide a proper basis for MPM measures.

- **Practical:** We also agree that the administrative processes used to implement MPM measures should be “understood, predictable and reasonable”, but would add the test that they meet these criteria “for market participants” (i.e. not just for the regulatory authorities carrying them out). In particular, market participants must understand not only what is prohibited (to avoid Type 2 errors), but must also be able to judge quickly what kinds of behaviour is permitted, so that they are not discouraged from competing (a Type 1 error).
- **Transparent:** This principle effectively defines what makes an MPM measure sufficiently “understood, predictable and reasonable for market participants” to avoid Type 1 and Type 2 errors. To count as transparent, decisions must apply replicable procedures using objective evidence in a predictable manner, i.e. in accordance with guidelines or previous decisions published earlier. MPM measures that do not meet this criterion—even if they meet all the other criteria—will create regulatory uncertainty, distort incentives, hinder the competitive process and discourage efficient outcomes.

As a market participant, we cannot stress enough the importance of MPM measures being transparent. We agree with NERA’s view that transparency is an important principle, “since measures will not promote competition if market participants are unsure how they will be implemented.”¹⁷ The omission of this principle from the appraisal shown on slide 66 of the RAs presentation at the workshop on 2 December 2015 was therefore a major omission, which we expect to be remedied in future documents. Since we expect MPM measures to evolve over time, as economic conditions change, it will also be essential to enact a transparent governance procedure that allows new measures to be proposed, made available for consultation, and withdrawn or amended in the light of comments, well in advance of their planned date of implementation. In other words, transparency is a key feature of the MPM procedure, as well of any MPM Measures.

It should be noted that the requirement for transparency, and hence for some published guidelines on what constitutes prohibited behaviour, applies to any form of MPM measure, whether it comprises “bidding principles”, “ex-post enforcement only” or a “market abuse licence condition”.

1.4. Overall Conclusions

Any MPM measures must be consistent with legal requirements. These legal requirements limit the range of compatible market design features. In particular, they do not allow for the imposition of overly prescriptive SRMC pricing bidding rules as they will not allow for adequate cost recovery by generators.

¹⁷ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, page.15.

Decisions to adopt or reject MPM measures must be based on an assessment carried out against principles that are both clearly defined and consistently applied.

For competition to thrive, MPM measures must set out transparently just what (kind of) behaviour is prohibited, so as not to discourage competitive behaviour.

2. Review of Current MPM Measures

In the Consultation Paper, the SEM Committee expresses its view that the current MPM measures have been successful.¹⁸ These measures comprise (1) the Bidding Code of Practice (BCoP – “has been effectively enforced” and “likely prevented...abuses”) and (2) the Market Monitoring Unit (MMU - “has worked well...especially in...enforcing BCoP”) as well as (3) Directed Contracts (“an effective measure to address concerns about structural market power”) and (4) Vertical Ring-Fencing (“effective...alongside other market power mitigation measures”¹⁹).

The SEM Committee’s approval of the BCoP is particularly important, since the BCoP is less prescriptive than the options that the RAs appear to favour, in particular as regards the Balancing Market.

2.1. Difficulties in Calculating SRMC

Discussion of the BCoP tends to focus on the requirement in paragraph 6 for generators to offer their output at the Short Run Marginal Cost (SRMC) of producing it over a Trading Day, valued at Opportunity Cost. Discussion of “prescriptive formulae” sometimes suggests that such prices are simple to define by reference to the fuel costs of Start-Up, No-Load and Incremental output, with an allowance for variable O&M per unit. In the Consultation Paper, the RAs assert that “In general, detecting deviations from marginal cost bidding is relatively straightforward, as exemplified [in Box 4.1] below, if each offer is linked to a specific generator, since the technical characteristics of the generator (e.g., efficiency, operations and maintenance costs, etc.), and its marginal costs can be independently calculated and verified with reasonable accuracy.”²⁰

However, Box 4.1 on page 33 of the Consultation Paper actually demonstrates that measuring marginal costs is not “relatively straightforward” but, on the contrary, is neither simple nor practical for regulatory authorities. As explained more in detail in section 4.3, Box 4.1 contains many computational errors, relies on unexplained assumptions, and considers an unduly narrow range of costs. If Box 4.1 contributes anything to the current debate, it shows the errors that are likely to emerge from any attempt to impose prescriptive rules on generator bidding.

2.1.1. Flexibility within the SEM

In contrast, the BCoP allowed for some flexibility in applying general concept of SRMC over a Trading Day:

- Paragraph 10 recognises that generator offers of Start-Up and No-Load costs may have to deviate from actual costs, because of vagaries in the scheduling algorithm that would otherwise “distort the true economics of the generation set or unit”. The nature of such adjustments would be a matter of judgement.

¹⁸ SEM-15-094, paragraph 7.3.1.

¹⁹ SEM-15-094, paragraph 15.

²⁰ SEM-15-094, paragraph 7.3.1.

- Paragraph 8(iii) recognises that SRMC includes “reasonable provision for [the cost of] increased risks to plant and equipment”. Such risks may arise from unusual patterns of operation, or from deferring essential repairs to maintain output.
- Paragraph 11 allows for the inclusion of the Opportunity Cost of constraints on running times, total emissions or total energy output. Whether it is necessary to include the cost of such constraints depends on how well the scheduling algorithm captures the technical parameters of each generator.
- Finally, in calculating the cost (“benefit foregone”) of generation, paragraph 8 recognises the possibility of generators deviating from the principles set out in the BCoP, if there is “good cause” for doing so.

Many of the BCoP rules cited above concern costs that have to be forecast or estimated, for a day or for longer into the future. The same costs will arise within the I-SEM, but forecasts and estimates of these costs by regulatory authorities would inevitably be subjective. Any attempt to impose specific values based on an administrative definition of SRMC would therefore be inconsistent with the need for transparency.

Hence, the BCoP is not as prescriptive a formula as what seems to be envisaged for the I-SEM balancing market. Indeed, the success of the BCoP, as noted by the SEM Committee, derives in large part from its design as a flexible set of bidding principles for the SEM. This flexibility will be needed even more in the I-SEM.

2.1.2. New problems arising from the design of the I-SEM Energy Trading Arrangements

Difficulties with fitting actual characteristics of generators into the available I-SEM bidding formats will require at least as much flexibility over the submission of Start-Up and No-Load costs, as in paragraph 10 of the BCoP, and over the cost of operating constraints, as in paragraph 11 of the BCoP.

Risks to plant and equipment (paragraph 8(iii)) will arise in the I-SEM just as much as in the SEM. Their Opportunity Cost depends on the estimated probability of a fault occurring and estimated value of the resulting loss of market revenues over the whole period of an outage, neither of which can be reduced to a transparent and objective “prescriptive formula”. Generators will have to develop innovative forms of bid to ensure that scheduling and dispatch take such longer term considerations into account.

As a result of the proposed changes to the bid formats available under I-SEM energy trading arrangements, generators will have to experiment with different forms of bid to ensure that their plant operates efficiently. Different generators may adopt different approaches to bidding (indeed, it would be surprising if they did not), and their approaches to bidding will vary over time, in the light of previous outcomes. The RAs will not be able to presume that there is any one correct way to bid in I-SEM energy markets, or that a particular form of bid will achieve a desired (i.e. efficient) generation schedule. Imposing such measures with the aim of preventing any abuse of market power may instead “run the risk of distorting competitive behaviour by not

sending efficient signals to market participants on where and when to increase output, schedule outages, enter or exit.”²¹ Such measures would not be properly targeted or proportionate, as discussed above.

2.1.3. Conclusions

The acknowledged success of the BCoP shows how any new MPM measures must offer flexibility when facing similar costs, to avoid Type 1 errors.

In practice, bidding into I-SEM energy markets will require more flexibility than currently allowed under the BCoP.

2.2. Implications for MPM Measures in the I-SEM

Despite the difficulties identified above, many of the proposals in the Consultation Paper require prescriptive rules that impose specific prices on the market (either directly by defining the competitive price or indirectly by prescribing a formula for offer prices). We explain below in section 4.3 why defining a prescriptive formula for prices is impractical. Here, we merely note that such approaches are inconsistent with the objectives of energy market regulation:

- Prescriptive rules will not allow the competitive process to develop
- Prescriptive rules jeopardise long-term financing of generators’ activities
- Prescriptive rules distort incentives and discourage efficient outcomes

Instead of prescriptive formulae, any MPM measures intended to restrict prices will have to be high-level rules, interpreted case-by-case (as described in section 4.1).

To create a predictable framework for competition, both the process of selecting bidding rules and the interpretation of these rules must be transparent, objective and predictable, and guided by legal obligations and regulatory principles (as described in section 1.3).

Therefore, we firmly believe that only an approach based on principles will support the competitive process and so produce the best possible outcome for consumers.

While favouring a principles-driven approach to defining MPM measures intended to restrict bidding practices, we explain in detail in Section 3 that regulatory scrutiny of offer prices cannot be reduced to a set of *maximum* prices set by prescriptive formulae. Some reductions in price below a maximum would reflect genuine reductions in cost, but other price reductions might be predatory. As a result, the RAs should consider adopting targeted measures aimed at limiting ESB’s ability to lower prices in order to increase its market share, and thus to harm competition. Furthermore, we foresee a need for measures governing ESB’s conduct in forward markets, so as to preserve a competitive structure in the generation and retail supply markets. We explain the need for such measures to preserve competition in Section 6.

²¹ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, page 14.

3. Identification of Candidates for MPM Measures

3.1. HHI and RSI as the Main Indicators

To target MPM measures and to reduce the compliance burden on market participants (which would otherwise raise the cost of participation, act as a barrier to entry and undermine conditions for competition), the RAs need to apply filters that identify those producers whose market power is potentially troublesome. Modelling results demonstrate that ESB will remain the largest player, even if its market share and market concentration (i.e. HHI) are expected to fall. The Consultation Paper reports a number of indices, all of which indicate that ESB is dominant or pivotal until 2024 at least, and concludes that the steady rise in ESB’s RSI means that “the potential for exercising market power at certain times is likely to increase”.²² In contrast to ESB’s position, “no other market player’s individual RSI falls below the 1.2 threshold in any of the half-hourly periods.”²³ These results indicate unequivocally that ESB will be a candidate for targeted MPM measures, to ensure that it does not distort competition in any relevant market, by raising prices, by withholding supply, or by suppressing prices.

3.1.1. Proposed indicators of market power

In the Consultation Paper, the RAs note that “market shares, RSI, HHI are usually used as long-term, ex-ante metrics” and “primarily focus on market structure”.²⁴ They therefore propose the following metrics to assess market power in the different markets:²⁵

- Market shares and HHI: as “ex-ante” metrics in the BM, IDM, and DAM markets to be used as “descriptive metrics by MMU in its regular reporting” and “to determine FCOs”;
- RSI (or PSI) as metrics in the BM, IDM and DAM “for ex-ante determination of the expected level of market power” and “to determine FCOs”.

The Consultation Paper notes that HHI and average RSI provide diverging results between 2016 and 2024: (1) a falling HHI, indicating “lower market concentration and a decline in market power overall”; but (2) falling average RSI for ESB, indicating “increasing market power concerns at certain times”.²⁶ The RAs attribute this difference to the rising market share of wind generation, which decreases ESB’s average market share but increases volatility and hence ESB’s market power at some times.²⁷

The Consultation Paper notes that this difference in results needs to be taken into account when developing MPM measures for the I-SEM.²⁸ The theme of differing results was taken up at the RA Public Workshop presentation on 15

²² SEM-15-094, Executive Summary, paragraph 10.

²³ SEM-15-094, paragraph 6.4.8.

²⁴ SEM-15-094, paragraph 5.3.2.

²⁵ SEM-15-094, paragraph 5.5.1, Table 5.3.

²⁶ SEM-15-094, paragraph 11.

²⁷ SEM-15-094, paragraph 11.

²⁸ SEM-15-094, paragraph 12.

December 2015.²⁹ The presentation given at that workshop states that, as measured by the HHI, the generation market becomes less concentrated, but installed capacity becomes more concentrated. Again, this divergence in trends is attributed to increased wind generation.³⁰ It leads to the conclusion that “Measured on an annual average basis, structural market power is expected to decline”, but that “the number of periods...when structural market power is a concern is expected to increase significantly”, so that “structural market power remains a concern for the future”.³¹ Indeed, although the HHI for annual generation and the Average RSI are moving in opposite directions, in 2024 they both remain at levels that are of concern³² as shown in Figure 1 below.

Figure 1: ESB’s Market Power: HHI and Average RSI

Metric	2016	2019	2024
HHI	2,617	2,237	1,667
Average RSI (ESB)	1.60	1.57	1.35

Source: SEM-15-094, Executive Summary, paragraph 11.

Contrary to these conclusions, representatives of ESB were quick to seize on the references to an expected decline in structural market power on an annual average basis. They offered these modelling results as evidence that ESB was not (or would soon no longer be) a source of concern over market power and should not therefore be subject to special MPM measures. However, proper analysis of the modelling results shows that the declining HHI for annual generation provides no grounds for relaxing controls on ESB, as indicated in the conclusions quoted above. The SEM Committee is therefore correct to conclude that ESB’s market power remains a concern for the (foreseeable) future.

3.1.2. Critique of proposed indicators of market power

The HHI for “annual generation” does not correspond to any of the relevant markets defined earlier in the Consultation paper, which are mostly half-hourly or perhaps daily. Measures of HHI derived from it are therefore unrelated to any particular market and potentially misleading.

The Consultation Paper proposed “to apply the granular definition of hourly product in the DAM and IDM, and half-hourly product in the BM.” (para 3.4.2). This is a conventional approach to electricity markets. In many cases, markets with similar conditions may be amalgamated into wider periods – for instance, the market for generation has sometimes been divided between “peak periods” and “off-peak periods”, each of which combines many (half-)hours with “high” or “low” demand, respectively.

²⁹ “I-SEM Market Power Mitigation”, SEM-015-099, slides presented at the RA Public Workshop, Crowne Plaza Hotel, Dundalk, 15 December 2015.

³⁰ SEM-15-099, slides 19 and 20.

³¹ SEM-15-099, slide 250.

³² The RAs previously defined a market with a HHI between 1,000 and 1,800 as “moderately concentrated”. Values above 1,800 indicate “significant potential for market power”. See SEM-15-031, I-SEM Market Power Mitigation Discussion Paper, 8 May 2015, paragraph 2.4.7.

In the I-SEM, the picture is complicated by the additional variation in output from wind generation, so that conditions are not defined by the level of demand alone, but by the degree of “stress” caused by the relationship between supply and demand. Large generators might have market power in periods of “high stress”, but not in periods of “low stress”.³³

“Annual generation” mixes high-stress periods with low-stress periods. Hence, the HHI for annual generation covers periods when large generators have market power and periods when they do not. Due to the growth in wind output, any annual measure of concentration is affected by the relative *frequency* of each set of market conditions within the year, rather than changes in the strength of market power in each market. Thus, the HHIs for annual generation do not indicate a decline in ESB’s market power. ESB’s market power is actually becoming more acute, as indicated by the Average RSI shown in table 6-15 and discussed in paragraphs 6.6.3 and 6.6.4 of the Consultation Paper.

The decline in HHI for annual generation does not therefore provide an accurate indicator as to the existence of market power in the I-SEM. The *level* of the HHI remains in the area of concern and the Average RSI indicates “increasing market power concerns” over the position of ESB.³⁴

3.1.3. Relevant indicators of market power

By comparison, measures of HHI for capacity and RSI come closer to describing the situation in physical markets at times of moderate-to-high demand, with low wind output. These are the periods when market power is most likely to be a problem and therefore provide the most informative basis for filtering candidates and for targeting MPM.

In this respect, the measure of HHI for capacity captures conditions in *energy markets during high-stress periods*, when large generators have the most market power. It also captures conditions in *(secondary) capacity markets*, when an independent capacity holder suffers a shortfall and must buy capacity from another capacity holder to avoid major penalties. Whilst the most recent I-SEM publication on the Capacity Remuneration Mechanism recognises the importance of secondary trades in capacity,³⁵ it omits any consideration of market power in these secondary trades (an area that must be addressed).

With respect to measurement of the RSI, the required margin over demand depends on the characteristics of the market. The Consultation Paper considers measures of RSI which compare generation capacity against demand plus a margin of either 10% or 20%. In the context of the I-SEM, a margin of 20% is more relevant.

- A margin of 10% (multiplier of 1.1) reflects the required capacity margin in thermal generation markets. Some analysts, for example,

³³ (Half-)Hourly periods might better be amalgamated into: (1) “high stress periods” with low wind output and moderate-to-high demand *or* high wind output and high demand; and (2) “low stress periods” with low demand *or* high wind output and moderate demand.

³⁴ SEM-15-094, paragraph 6.6.3.

³⁵ SEM-15-014, Capacity Remuneration Mechanism: Detailed Design - Second Consultation Paper, 21 December 2015, section 3.2, pages 48-51.

used it as a measure of an adequate capacity margin for Great Britain, following the “dash-for-gas” that created a large and reliable fleet of CCGTs.

- A margin of 20% (multiplier of 1.2) better suits electricity markets that are small and/or that are facing additional risks (like intermittent generation). The I-SEM falls into this category.

Evidence of this difference is provided in documents issued by the TSOs and by the SEM Committee. When discussing reserve requirements, both noted that the biggest in-feed is only 7% of demand in Great Britain, but as much as 20% of demand in the SEM.³⁶ This evidence confirms that the RSI is a more relevant measure for the I-SEM if it includes a margin of 20% rather than 10%. On that basis, the values of RSI calculated in the Consultation Paper remain high enough to cause major concern out to 2024.

Both the HHI and RSI indicate that ESB’s market power will persist, until 2024 at least, in peak/stress hours.

These results indicate unequivocally that ESB will be a candidate for targeted MPM measures, to ensure that it does not distort competition in any relevant market, by raising prices, by withholding supply, or by suppressing prices.

The dominant or pivotal position of ESB will translate into additional market power in secondary markets for capacity.

3.2. Other Indicators and the SCP Framework

The RAs have proposed using metrics of Conduct and Market Performance metrics to assess market power, such as indices of mark-ups, along with analysis of withholding, generators’ net revenue and liquidity.³⁷ However, none of these measures are used to reach conclusions in the Consultation Paper.

The only numerical analysis of conduct contained in the Consultation Paper relates to price-setting, i.e. the number of periods when individual generators will be setting the price. The RAs note that even small generators may set the price in several periods, as shown in table 6.13. They suggest that these generators possess market power because the “next unit in the merit order” submit substantially higher offer prices.³⁸ However, this may be a case where proper analysis of Conduct indicates that there is no problem. Many factors determine the profitability to such generators of raising their offer prices. The next best alternative is not just next unit in merit order. Often, if a generator raises its offer price, the scheduling algorithm will find a relatively low cost substitute, merely by changing the running regimes of other generators. These possibilities set a rather lower cap on each generator’s offer price than the obvious comparison with the “next unit”. Only detailed analysis of

³⁶ SONI and Eirgrid, *Dispatch Model for the All Island Market / Transmission System*, paper SEM-12-105b, November 2012, page 10.

CER and UREGNI, *High Level Design for Ireland and Northern Ireland from 2016*, Consultation Paper, SEM-14-008, 5 February 2014, para 3.3.11.

³⁷ SEM-15-094, paragraph 5.5.1, Table 5.3.

³⁸ SEM-15-094, paragraph 6.4.25.

alternative schedules compiled under different assumptions about “conduct” in the market would allow the RAs to reach an informed conclusion as to which individual generators (1) possess any market power and (2) separately, require MPM measures as a result.

On the other hand, in forward markets, ESB’s Conduct should raise concerns over market power and liquidity, even if analysis of the Structure of forward markets does not. We explain these concerns fully in section 6 below.

As discussed in section 1.3 above, on Key Principles, an “effective” filter will not only identify market participants that have market power, but will also exclude market participants that provide competitive pressure. The Consultation Paper recognises the “**SCP**” framework (in para 5.1.2), but concentrates on **S**tructural data as the basis for defining filters. These filters will give misleading indications about the market (Type 1 and type 2 errors), unless augmented by consideration of **C**onduct and **P**erformance.

Design of effective Structural filters will require further work on Conduct and Performance given the Consultation paper’s focus on structural measures.

4. SRMC as the Target for “Competitive” Pricing

4.1. Conflict Between Prescriptive Controls and Key Principles

The Consultation Paper defines the exercise of market power as generators either by not offering plant into the market or by offering it with an offer price in excess of Short Run Marginal Cost (SRMC).³⁹ In the view of the RAs, generators should not even offer plant at prices raised above SRMC to include their own expectation of scarcity rents or future inframarginal rents.⁴⁰ However, at various points in the Consultation Paper, the RAs show a preference for proposals using “prescriptive formulae” to define each generator’s SRMC.

Such tight regulation of offer prices conflicts with several of the “key principles” discussed above. First, it is unlikely to be “practical”. Second, the prevalence of Type 1 and Type 2 errors will prevent competition from flourishing. It will also jeopardise the long term financing of generators’ activities, by preventing cost recovery. Such policies will not therefore be “effective” in protecting competition against the exercise of market power. Third, formulae would require subjective assumptions and will not be “transparent”. The only practical and effective policies will be those based on transparent principles, i.e. guidelines describing what kinds of behaviour are deemed to be anti-competitive, and allowing some flexibility in the compilation of competitive offer prices.

In the light of these observations it is also clear that prescriptive formulae are inconsistent with applicable legal requirements, including the requirement for proportionality in particular. Opting for the tight regulation of offer prices would display a lack of consideration of the requirement on the part of the Minister and CER to have regard to the need to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake. Tight regulation of offer prices also constitutes an unjust attack on the property rights of generators and their rights to earn a livelihood.

We do not believe that these concerns could be overcome by recourse to forms of capacity payments or similar contracts as, in this particular context, the latter at least would most likely constitute impermissible State aid. It is clear from the European Commission's Guidelines on State aid for environmental protection and energy 2014-2020 that aid may be acceptable where it addresses a specific and identified issue of generation adequacy and it remunerates solely the service of pure availability provided by the generator, to the exclusion of remuneration for the sale of electricity. This means that market design shortcomings as regards the ability of generators to recover their (efficient) short run marginal cost of generation could not be addressed via State aid measures. Instead, any market design seeking to mitigate market power must still allow all generators sufficient flexibility to compile competitive offer prices. As the European Commission made clear in its 2013 Communication on delivering the internal electricity and making the most of

³⁹ SEM-15-094, paragraph 8.2.6.

⁴⁰ SEM-15-094, paragraph 4.2.6.

public intervention, measures aimed at generation adequacy,⁴¹ *“the causes for generation inadequacy and reasons why it might not be remedied by the market alone must be properly identified and **removed** in line with European Union legal requirements, **including regulatory failures such as wholesale and retail price regulation** and negative impacts on investment decisions of existing generation support schemes for fossil and nuclear generation.”* (our emphasis)

In other words, wholesale price regulation must ensure that generators receive appropriate investment incentives and this in turn will require that they are in the position to finance the activities for which they are licensed. This is a critical element in the choice of the appropriate power mitigation policy for I-SEM.

4.2. Contrasting Proposals in the Consultation Paper

With respect to Day-Ahead (DA) and Intra-Day (ID) markets, paragraph 8.9.3 sets out a range of options: (1) prescriptive bidding controls; (2) bidding principles and ex-post enforcement; (3) ex-post enforcement only; and (4) a market abuse licence condition. In paragraph 8.9.8, the RAs effectively rule out the first option for DA and ID markets, leaving only the more flexible options.

However, in paragraph 8.7.3, the RAs set out three options for the Balancing Market (BM), all of which rely on replacing certain generator bids with “formulaic/prescriptive SRMC bids”, applied (1) “manually and ex-post”, (2) through “automated intervention” or (3) “ex-ante at formulaic SRMC levels for all trades in the BM”.

This preference for prescriptive formulae in the BM is undermined by the arguments used in the Consultation Paper to reject such controls in the DA and ID markets. Many of these arguments apply equally to the BM.

For instance, in relation to the DA and ID markets, the Consultation Paper states that prescriptive bidding controls would be “less practical” and “difficult to implement in practice” because bids would need to reflect different operational conditions, including the “likely running pattern over the following 24 hour period”. It concludes that no single prescriptive formula for SRMC bid is likely to describe “the cost characteristics of every generator under all possible market and operational conditions”, leading to “frequent deviations from the prescribed SRMC values”.⁴²

All of these arguments apply equally to generators bidding in the BM. The “formulaic/prescriptive” approach to the BM therefore defines an unduly narrow range of options for this stage of the consultation. However, at the RA Public Workshop held in Dundalk on 2 December 2015, panel members stated in response to a question that the omission of any principles-based option was a “drafting oversight”. They pointed to paragraph 8.7.5 as evidence of a willingness to allow flexibility (“innovation”) in the interpretation of SRMC in the BM.

⁴¹ Communication of 5 November 2013, C(2013) 7243 final.
⁴² SEM-15-094, paragraph 8.9.7

There was widespread agreement at the RA Public workshop, among delegates and presenters alike, that more flexible options should be considered for the BM.

We believe that having regard to the significance of this matter, it would have been appropriate and consistent with the RA's obligation of transparency that a clarification be published and we requested that the RAs do so in our letter of 23 December 2015. In the RAs' letter of 15 January 2016, the RAs acknowledge a level of ambiguity in the Consultation Paper but disappointingly say that no clarification is required, and furthermore that "it is clear that the SEM Committee does not consider Option 4, the least interventionist of the options in the DAM and IDM as appropriate for the BM". For the avoidance of doubt, we do not believe that any explanation, let alone a satisfactory explanation, is offered in the Consultation Paper why "Option 4" should not even be *considered* for the BM. In any event, the letter continues to say that "There is also scope of for these [ex ante bidding] principles to apply to the energy actions in conjunction with a number of BM options, such as option 1 and 2 (A and B)".

We therefore assume, consistent with the RAs' obligations, that flexible options in respect of the BM have not been ruled out and that the final decision on MPM Measures will at least consider – and, in the light of the evidence, adopt – a principles-based approach to mitigating market power in the BM.

4.3. *Incompatibility of Competition with Narrowly Defined SRMC*

We would have major concerns about any attempt to tie offer prices to a formulaic definition of SRMC. In the first place, the economic concept of SRMC does not define the competitive price in any market where producers experience economies of scale. In the electricity market, economies of scale are represented by the fixed costs that generators must incur in order to produce any output. Given the existence of these fixed costs, prices tied to SRMC would prevent producers from covering their fixed costs in the long run, and destroy the incentive for efficient production in the short run.

Box 4.1 on page 33 of the Consultation Paper is an attempt to show how generators should offer plant to recover fixed costs, but the calculation is full of computational errors, relies on unexplained assumptions, and only considers a very narrow range of costs.

Box 4.1 describes the calculation of SRMC for a 50 MW generator with a "marginal cost" of €50/MWh, but it contains the following errors:

- The Box states that the generator incurs another cost of "€500/start". It claims that is equivalent to "€2,500/hour", but that cannot be true.
- The Box then states that the generator has a no-load cost of "an additional €50/MWh (the unit cost of running one extra hour,)". However, no-load costs are not defined as unit costs *per MWh*, but in € *per hour*.
- The Box also says that the generator has to run for a *minimum of two hours*, but the calculation of its offer price assumes that the generator sells energy in only *one hour*, which is impossible if it runs for two hours. (Even energy not sold on the BM would be spilled and would attract some

payment or penalty, which would have to be taken into account when calculating the SRMC of running for one hour.)

- The formula for the offer price per unit of output appears to sum the marginal cost, a start-up cost and a no-load cost. However, the start-up cost is stated per unit of *capacity*, rather than the cost per unit of *expected output*. The no-load cost is included for *one hour*, even though the plant would incur no-load cost for the *two hours* of minimum run-time.
- The formula for the start-up cost therefore seems to assume that the generator will achieve full output in one hour of running (an unstated assumption) and zero output (or zero sales) in the other hours when it is running (another unstated assumption). It also adopts an inconsistent view on the allocation of the no-load cost, which is said in different parts of the Box to occur for either one hour or two hours.

Whereas computational errors can be corrected the other problems with Box 4.1 show why trying to control market power with prescriptive formulae would not be practical or effective.

First, conversion of fixed costs into a cost per unit of output requires some assumption about the future output (and running time) of the generator. The owners of these generators will have to make such assumptions, based on what they can learn about the resources available to the system and the algorithm used for scheduling and dispatching plant. However, such assumptions can only be subjective estimates, formed at the time of bidding with the information available at that time. It would be unjustifiable to prescribe offer prices based on the actual output of the generator, as observed *ex post*, because that would treat simple forecasting errors as an abuse of market power.

Second, Box 4.1 appears to allow for start-up costs and no-load costs, both of which are fixed costs incurred in the short-term before the generator can start producing output. However, generators incur many other kinds of fixed cost for the same purpose, which Box 4.1 fails to acknowledge. In contrast, the current Bidding Code of Practice recognises many of them. The core of the BCoP – the principle of bidding SRMC, defined over a Trading Day and valued at Opportunity cost – is stated in paragraph 6. However, as we explained in section 2.1.1 above, other parts of the BCoP recognise cases that require a broad interpretation of this core principle:

- The need for generator offers of Start-Up and No-Load costs to deviate from actual costs to offset vagaries in the scheduling algorithm (paragraph 10);
- The need to make “reasonable provision for [the cost of] increased risks to plant and equipment” (paragraph 8(iii));
- Inclusion of the Opportunity Cost of constraints on running times, total emissions or total energy output (paragraph 11); and
- A general provision for generators to deviate from the principles set out in the BCoP, if there is “good cause” for doing so (paragraph 8).

These bidding principles cover a wide range of different costs that are associated with producing output in the short run. As a practical matter, no

prescriptive formula could ever anticipate these costs accurately. Box 4.1 illustrates exactly the kinds of mistakes and unspoken but subjective assumptions that will undermine any attempt to prescribe a transparent and objective formula for SRMC.

For example, the costs of “increased risks to plant and equipment” requires at least some allowance for the possibility of: (1) the cost of additional maintenance (required in the future if the plant continues to run with a fault); (2) the cost of major repairs to the plant (if it actually fails); (3) the potential loss of future earnings from the markets for electricity and capacity (whilst the generator is offline for repairs); and (4) many other costs specific to individual cases.

Estimating these costs would require the regulatory authorities to make a large number of subjective assumptions about individual cases. On the other hand, just omitting these costs from prescriptive formulae for “SRMC” would set offer prices too low to permit competitive market pricing. In many cases, they would set prices below the marginal cost of production and so would distort incentives and discourage efficient production, rendering them ineffective as controls on market power.

The possibility that generators might be prevented from including certain costs in offer prices would be particularly troubling, since it might render them unable to finance their activities. Difficulty in covering costs and financing activities would prevent consumers from receiving the services they demand, both by discouraging efficient output from generators, and by preventing generators from investing in capacity.

The latest Generation Capacity Statement published by EirGrid and SONI foresees generation capacity being sufficient to meet the adequacy standard until 2024.⁴³ However, these forecasts rely on notifications provided by generators and underpinned by projections of future revenues. Currently, these notifications are likely to be predicated on revenues continuing at the current levels. Any reduction in revenues under the I-SEM (due to a change in the capacity mechanism or tighter restrictions on generator bidding) would cause generators to lower the projections of their future revenues, which may lead to earlier plant closures. Such closures would put capacity adequacy in jeopardy for the market as a whole over the period to 2024, but plant closures within constrained areas would cause problems for network management much sooner than that. It would therefore be a great mistake to select MPM Measures on the assumption that generation capacity will always be sufficient, regardless of the incentives offered by the new system.

Thus, prescriptive controls that omitted relevant costs (such as those listed above) would not comply with general legal principles. Moreover, by the standard of the “key principles”, prescriptive controls that omitted relevant costs would not provide a *practical* or *effective* basis for controlling market power.

Any attempt to build these costs into a prescriptive formula would also fail to apply the key principles. Each of the costs described above requires an

⁴³ EirGrid and SONI, *All-Island Generation Capacity Statement 2015-2024*, “Key Messages”, page 5.

assessment not only of future costs, but also of the probability that they will occur at an individual generator. No prescriptive formula imposed by the RAs could apply such concepts without resorting to either subjective or arbitrary assumptions. Such assumptions would conflict with another key principle, namely the need for controls to be *transparent*.

4.4. Competitive Prices in Complex Markets

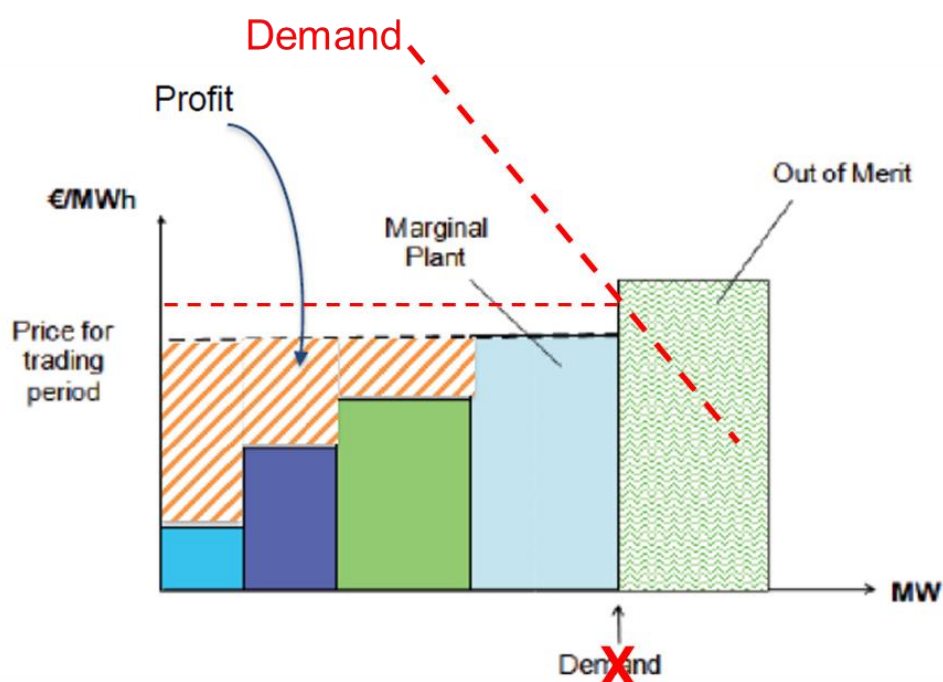
The Consultation Paper states as a principle that generator offer prices should be tied to SRMC and should not include “their own expectation of scarcity rents or future inframarginal rents in their offers”.⁴⁴ This statement represents an incomplete view of both competition and price regulation.

4.4.1. Discrete offer prices

Figure 2 below is a diagram used in the RA Public Workshop on 2 December 2015 to illustrate SRMC pricing, with a minor adjustment to show when such a rule would need to be adapted. The blocks represent different generator offers, with volumes measured on the horizontal axis and offer prices measured vertically. Assuming a fixed level of demand (marked in black text and a red cross on the horizontal axis), the presenters defined the competitive price as the offer price of the fourth generator. This competitive price is indicated by the horizontal dashed line in black. However, in these conditions, the competitive price could in fact be any price between that price (the fourth block) and the price of the next most expensive generator (the fifth block, marked here as “out of merit”). Indeed, either end of this range could be regarded as the opportunity cost of production. We understand that the RAs might wish to set the market price at the lower level for regulatory purposes, but in some conditions that rule will not provide a sustainable outcome.

⁴⁴ SEM-15-094, paragraph 4.2.6.

Figure 2: Competitive Prices For Stepped Supply Curves



Source: SEM-15-099, slide 28 of 71

Demand in an electricity market is not always defined as a fixed amount, but often depends on the price, as shown by the sloping dashed line coloured red in Figure 2. This demand curve equals supply on a vertical section of the supply curve, between the offer prices of the fourth and fifth generators. The competitive market price, at which supply and demand are equal, is given by the horizontal dashed line coloured red. It represents the opportunity cost of the marginal demand, rather than of any particular source of supply. This price lies above the offer price of the fourth generator but lowering the market price would result in excess demand. That excess demand could only be met by producing output from the fifth generator, even though the market price is *less* than that generator's own SRMC. Such outcomes would not be sustainable or efficient.

In this example, a generator might set its offer price above its SRMC and yet produce a competitive market price, because the competitive market price would lie above the SRMC of the most expensive generator running at the time. The RAs would therefore be imposing non-competitive outcomes if they forced generators to bid or to accept a lower price for regulatory purposes.

4.4.2. Predatory pricing

We note that paragraph 8.7.5 expresses a desire for SRMC formulae to allow generators to “innovate to a certain extent, in driving down costs”. Whilst driving down costs is desirable, the unfettered ability to offer prices below SRMC would permit undesirable behaviour in the form of a predatory pricing strategy (or price suppression). Such behaviour is defined in the Consultation Paper as the consequence of market power, whereby “generators offers at

prices below the competitive level to increase their market share in detriment of competitors.”⁴⁵

Privately owned firms rarely find predatory strategies to be profitable; they can easily charge low prices to drive competitors out of the market, but usually they cannot recoup their losses by charging high prices afterwards, without prompting entry by new competitors (or regulatory interventions). However, a state-owned firm such as ESB is not motivated only by profit but could also be motivated to use “its market power to achieve political objectives”⁴⁶. For example, as stated in NERA’s June 2015 report “it may come under pressure to lower energy prices, leading to predation, or it may be driven by management objectives to maintain or expand its market share, even when it would be unprofitable to do so.”⁴⁷ The threat of predation (i.e. under-pricing) by ESB was a major factor behind the design of bidding principles in the SEM. The I-SEM changes nothing in this regard, as indicated by the modelling results quoted in section 3.1 above, so any constraint on offer prices must address anti-competitive suppression of prices, as well as price increases.

4.4.3. Conclusion

This observation reinforces our conclusion that regulatory scrutiny of offer prices cannot be reduced to a set of *maximum* prices set by prescriptive formulae. Some reductions in price below a maximum would reflect genuine reductions in cost, whilst others might be predatory. Evidence on pricing behaviour will therefore always require careful interpretation of bidding guidelines or principles.

4.5. Application to DA and ID Markets

The Consultation Paper applies the same principle of SRMC pricing to all markets, but seems not to acknowledge that the concept, or measure, of SRMC may differ between different types of market.

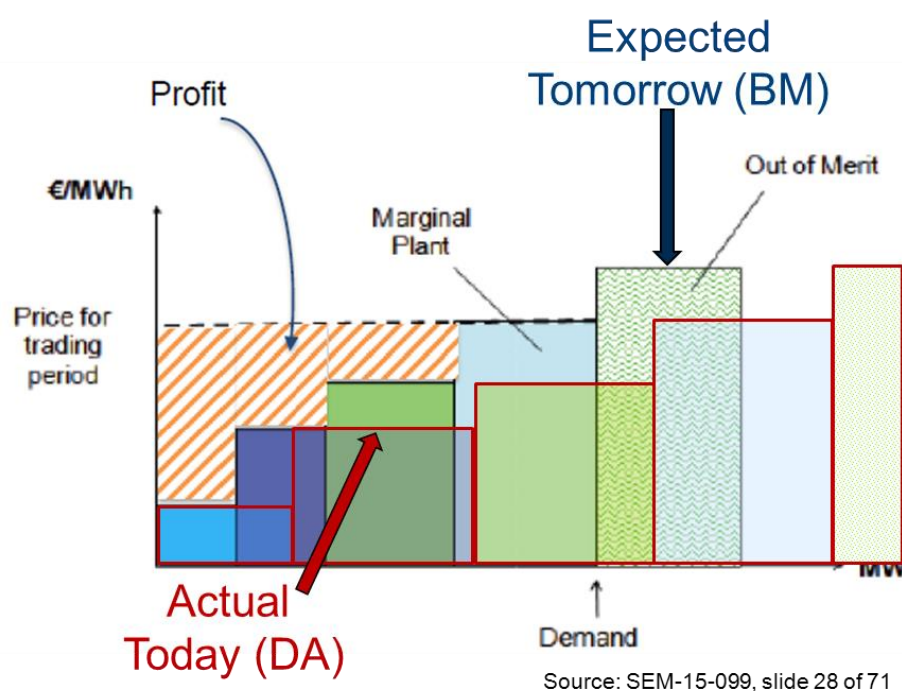
Figure 3 below takes the same diagram as before and amends it to show the interaction between the Day Ahead Market and the Balancing Market from the point of view of day-ahead bidding. The supply curve and the (fixed) level of demand expected to apply in the BM tomorrow are shown in black. Ignoring the complications listed above, the expected “Price for trading period” is defined by the horizontal dashed line.

⁴⁵ SEM-15-094, paragraph 4.2.4.

⁴⁶ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, Chapter 4.1, p.10.

⁴⁷ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, Chapter 4.1, p.10.

Figure 3: Pricing in Forward and Real-Time Markets



Generation actually available today for sale in the DA market is shown by the second set of blocks, outlined in red. For each generator, today's available capacity is higher than the level of capacity expected to be available tomorrow, because of the possibility that an outage occurs in the meantime. Comparing forecast demand with contemporaneous day ahead supply might suggest that the DA price should be set by the *third* generator's offer price, but that would be incorrect. The DA price ought to be equal to the price expected to apply in the next day's BM (subject to any premiums for differences in risk or liquidity). It should therefore be set by the offer price of the *fourth* generator (equal to the price expected to apply in the BM).

In the DA market, participants can drive up its price to the required level by including additional (virtual) demand bids, or the third generator can submit an offer price in excess of its SRMC. The RAs may favour one approach over the other for regulatory purposes. However, some flexibility will be required when interpreting observed day ahead prices, to avoid the suggestion that market power raised it above the *contemporaneous SRMC*, when in fact it settled at the competitive level defined by the *expected SRMC* in tomorrow's BM.

4.6. Conclusions

The Consultation Paper uses a narrowly defined SRMC as the benchmark for competitive pricing and applies it to all market participants in all "physical" markets (i.e. the DA and ID markets as well as the BM). However, generators incur a variety of fixed costs to produce output in the short term. It is not practical to anticipate all these fixed costs in a formula. Prescriptive or formulaic rules limiting the scope of offer prices to SRMC would prevent recovery of these costs, putting at risk the long term financing of generator's activities and eliminating generators' short term incentive to produce.

Furthermore, competitive pricing in the DA and ID markets will follow the principles of forward markets and will reflect *expected* future BM prices, rather than the SRMC of physical supply or demand at the time of bidding. It is not practical to set up an objective formula that captures this kind of pricing.

Because of the wide-ranging and unpredictable nature of fixed costs, and the subjective nature of pricing in forward markets, no prescriptive formula for SRMC will ever be effective as a means of controlling market power and allowing competition, in the BM, the DA and ID markets, or any other market in the I-SEM.

Prescriptive rules on SRMC pricing will not promote efficient competition, are inconsistent with applicable legal requirements, and will deny consumers the services they require.

A practical and effective MPM measure, that minimises both Type 1 errors and Type 2 errors, must couch restrictions on bidding or pricing in terms of principles (similar to, or adapted from, those in the BCoP). That applies as much to the BM as to any other market in the I-SEM.

The interpretation of any future bidding principles must be flexible enough to deal with all future cases and objective or transparent enough to give market participants clarity over what competitive behaviour is allowed, as well as what abuses are prohibited.

5. Specific Problems with SRMC Pricing for Transmission Constrained Generation

The problems described in section 4 are particularly acute for generators operating behind a transmission constraint, since their revenues accrue largely at their own offer price, rather than at a market price. Limiting offer prices to a narrowly defined SRMC threatens cost recovery in the short and long term, thereby distorting incentives to produce electricity and to maintain generator plant efficiently.

Below, we use the example of a transmission-constrained generator to illustrate the problems that would arise from using prescriptive formulae tied to SRMC to define allowable offer prices, to set market prices, and to justify revenues.

5.1. *Transmission Constraints and Relevant Markets*

The Consultation Paper notes that the “relevant market is defined by the interaction between transmission constraints, the location of demand and the nature of generation supply offers”.⁴⁸ However, these conditions change “on a continuous basis and transmission constraints may evolve”; as a result, “localised market power can arise, and move over time”.⁴⁹

The RAs note that, at the limit, “a constrained area with a single generator” may constitute a relevant market within the BM.⁵⁰ This definition of a relevant market may apply within a single hour or across a whole day, if the TSO has no alternative way to operate the transmission network. However, within that timeframe or in the longer run, even a “single generator” behind a transmission constraint faces competition from a variety of sources, including: (1) reconfiguration of generation and the transmission system; (2) demand-bidding within the constrained part of the network; (3) small investments in the transmission network; and (4) new generation capacity built within the same area. These possibilities widen the definition of the relevant market viewed over a longer period, i.e. taking many (half-) hourly markets together.

The RAs may still decide to adopt MPM measures to prevent abuse of market power in the short term. However, the identification of such abuses depends on the definition of a “competitive” or justifiable price for generators behind a transmission constraint. Unfortunately, the principles set out in the Consultation Paper take a very restrictive view of offer prices in transmission-constrained markets which will prevent generators from covering all the costs associated with their output. The resulting prices will not be competitive, will discourage efficient production by incumbents and will deter competitive entry by others.

The specific case of transmission constrained generation therefore shows why the general approach of prescriptive formulae for offer prices based on narrowly defined ideas of SRMC will not provide practical or effective MPM measures.

⁴⁸ SEM-15-094, paragraph 3.2.4.

⁴⁹ SEM-15-094, paragraph 3.4.4.

⁵⁰ SEM-15-094, paragraph 3.5.5.

5.2. Difficulties Created by the Proposals

The Consultation Paper discusses SRMC pricing at many different points, but paragraph 4.2.6 neatly encapsulates both the RAs' current views on MPM measures and the difficulties they would create for transmission-constrained markets and for generators operating within them. In that paragraph, the RAs state that "generators should not be allowed to include their own expectation of scarcity rents or future inframarginal rents in their offers". We believe that application of this statement would be both impractical and inconsistent with the promotion of efficiency and competition.

Behind the RAs' view is a desire for administrative convenience – specifically, the desire to differentiate more easily between "the exercise of market power and genuine legitimate behaviour leading to high prices due to scarcity". The RAs therefore want generators to tie their offer prices to their own SRMC. The RAs acknowledge the importance of adjusting market prices for scarcity, but suggest that aspect of pricing is best addressed by "appropriate market design". In that context, they refer specifically to "administered scarcity pricing" (raising prices in scarcity conditions) or "virtual bidding" (promoting convergence between market prices).⁵¹

Whatever market design is finally adopted, we foresee a number of difficulties applying the proposed approach to more narrowly defined markets, and to transmission-constrained generation in particular.

5.2.1. Economies of scale and fixed costs

First, economies of scale and the recovery of fixed costs means that SRMC pricing is a particularly inappropriate rule for generators remunerated largely at their own offer price. As discussed in section 3, such pricing rules would prevent those generators from covering all the costs associated with output and would therefore discourage efficient production. In the short term, problems arise over the numerous avoidable fixed costs incurred to permit a generator to run for one day, including some or all of the following:

- The labour cost of any extra shift called into work when the generator would otherwise be idle;
- The wear and tear (i.e. hourly depreciation) on parts and equipment that have a life limited to a defined number of running hours (after which maintenance is required);
- The cost of contract penalties for deferring maintenance, to allow the generator to run when needed;
- The opportunity cost of risks associated with running plant with a fault, including the possible cost of future repairs and loss of earnings.

If a generator is required to keep plant available because the TSO requires it to support the system, it incurs additional fixed costs over a longer period, such as the cost of the actual maintenance outages required after a certain number of running hours. Closing down a generator would save on (1) grid fees, (2) the financing cost of meeting credit requirements with electricity

⁵¹ SEM-15-094, paragraph 4.2.6.

markets, gas networks and fuel suppliers, and (3) PSO levies. It would reduce the cost of insurance and property taxes (business rates), which are revalued if a generator is not running. These costs therefore all represent costs of continuing to operate. Unless the generator is allowed to recover these costs through its prices, it will not be able to finance its activities.

5.2.2. Definition of opportunity cost pricing

Second, competitive pricing would provide a means of covering these costs if it is defined, not by the generator's own cost of production, but by the opportunity cost of the *next best alternative*. In some cases, the cost of investing in the network to remove a constraint is little higher than the cost of running a generator to manage the constraint, and provides an alternative limit on prices. A generator that set its offer price at the cost of the alternative should not be deemed to be abusing the market in all cases. The resulting margin over the generator's own *marginal* cost of production contributes to its fixed costs, which is important if there are economies of scale. Furthermore, charging the higher price gives alternative providers an incentive to enter the market, at a lower total cost than the existing generator.

Thus, even if it were possible to calculate SRMC accurately (which it is not), it would sometimes be anti-competitive to order generators to set their offer prices equal to their own marginal cost of production.

5.2.3. Local market signals

Third, even if market design addresses scarcity in the general I-SEM electricity markets, there is unlikely to be an equivalent solution for smaller markets, like transmission-constrained sections of the network. It would be impossible to apply local scarcity pricing to such smaller markets without dividing the I-SEM into nodal or zonal markets, which has been rejected. Relying on virtual bidding would be infeasible, because the TSO is the only customer for transmission-constrained generation in the BM, and generators cannot submit localised bids for their own output.

A shortage of generation behind transmission constraints may therefore coincide with a general surplus of generation capacity. Such conditions prevent the Administered Scarcity Price from being invoked, drive down revenues in the Capacity Remuneration Mechanism and even reduce infra-marginal rents in the Energy Trading Arrangements. The only way for the valuable generation behind a transmission constraint to cover its costs would be to raise its offer prices.

If generators operating behind a transmission constraint are prohibited from charging prices that cover all their costs, they will not continue in operation. Very soon, the TSO will face major problems for the security of the system, resulting in higher costs or a lower quality of supply.

5.2.4. Limits on the role of contracts

We recognise that contracts signed by the TSO and the generator concerned may offer another way to achieve efficient outcomes. However, such contracts do not remove the need to allow flexibility in setting offer prices.

- On the one hand, transmission constraints can arise unpredictably and at short notice. Some prove to be only ephemeral, creating a geographically separate, but very short-lived “relevant market”.
- On the other hand, it takes considerable time and effort to put contracts in place. Indeed, it is highly likely that such contracts would have to be notified to the European Commission under State aid provisions and amount to State aid, which would impose a significant delay.⁵²

As we noted in section 3.1 above, it is clear from the European Commission’s 2013 Communication as well as the 2014 Environment and Energy State Aid Guidelines that, before State aid is approved by the European Commission, Member States will be required to demonstrate that regulatory causes for State intervention have been addressed first and removed. It is only where this is not sufficient or possible that State aid may be considered. Reliance on ad-hoc contracts to address capacity issues arising from an inadequate remuneration mechanism for energy generation is accordingly not an option.

Furthermore, only the prospect of paying high prices in the BM will encourage the TSO to conclude a contract with a generator (or to turn to alternative providers of the service). Meaningful negotiations between generators, the TSO and the RAs will not be possible if the TSO and the RAs believe that generators will, or are obliged to, keep plant available for several years regardless of revenue levels. In reality, generators will close plant in the event that fixed and variable costs are not recoverable along with a reasonable rate of return.

Contracts are therefore no solution to the difficulties facing transmission-constrained generation, unless bidding rules give all generators appropriate flexibility over how they set their offer prices.

5.3. Conclusions

Any MPM measures designed to restrict offer prices must allow the TSO to purchase the output of transmission-constrained generators at prices which cover all the associated costs, which maintain the incentive to produce and which allow market participants to achieve an efficient outcome.

Prescriptive rules will not meet these needs, for the reasons set out in section 3. A prescriptive formula for offer prices based on a narrow definition of SRMC will not define the competitive or efficient price in transmission constrained markets. In the long-run it will jeopardise the ability of generators to finance their activities. In these cases, any adverse impact on incentives to generate and to maintain capacity will quickly lead to a decline in system security. As such the proposed rules are contrary to the requirements set out in the Electricity Security of Supply Directive. They are also at odds with the statutory duties of the CER and unjustly attack the property rights of generators.

⁵² In its decision in case SA.35980 – United Kingdom, Electricity Market Reform, Capacity Market – the European Commission found that the measure concerned conferred an advantage on certain undertakings as it allowed “*capacity providers to receive an additional compensation beyond that which they would obtain on the electricity market*”.

The case of transmission-constrained generation therefore illustrates the general problem with setting prescriptive formulae for offer prices in the BM. It reinforces the conclusion, reached above, that practical and effective MPM measures in the BM, as in all I-SEM markets, must be defined as flexible and transparent bidding principles.

The same conclusions on MPM measures apply to generators in transmission-constrained areas as to those in the wider market:

Prescribed rules for SRMC pricing will not promote efficient competition, are inconsistent with applicable legal requirements and will deny consumers the services they require.

In particular, prescribed rules for SRMC pricing may deny consumers access to the support that generators provide to the network in transmission-constrained areas.

A practical and effective MPM measure for generation in transmission-constrained areas, that minimises both Type 1 errors and Type 2 errors, must couch restrictions on the bidding or pricing in terms of principles that are flexible enough to cope with rapidly changing conditions and also transparent enough to indicate what behaviour is prohibited and what is not.

6. The Forward Market

6.1. Overview

The Consultation Paper on market power discusses forward markets, but concludes that there is no evidence of market power in such markets and that contract trading is best overseen by financial regulators applying European directives and related regulations. In the opinion of Energia, and indeed in the opinion of many suppliers and independent observers such as ESRI, both these conclusions are incorrect.

Energia has already submitted evidence to the SEM Committee of serious liquidity issues in the forward market and highlighted the problems it causes for competition⁵³. We note these concerns are unlikely to be addressed by the financial regulations on trading behaviour, since they concern decisions *not* to trade.

Market power in the forward market and its implications for competition are closely intertwined with problems of liquidity. If the MPM Workstream decides not to address market power in the forward market, we are concerned that it may not be addressed elsewhere. In any case, it is vital that the Forwards and Liquidity Workstream is allowed (or, indeed, ordered) to address both illiquidity and market power in the markets for forward contracts.

6.2. *Proposals in the Consultation Paper*

Throughout the Consultation Paper, discussion of market power in forward markets rests on the structural analysis and the apparent lack of barriers to entry into this market.

The RAs define the relevant market for forward contracts as all trading before the day-ahead stage, without reference to specific contract forms or purposes.⁵⁴ They suggest that the ability to abuse market power in the forward market is “weaker” than in physical markets,⁵⁵ due to (1) the potential for arbitrage (“Temporal interaction”) between markets⁵⁶ which implies a “high elasticity of demand”,⁵⁷ and (2) lower barriers to entry, “given that large-scale assets (generation plants) do not need to be built in response to price signals”.⁵⁸

The RAs note the limited number of firms offering “forward CfD/hedges” but offer explanations for the lack of supply based on economic factors that do not

⁵³ Baringa (2014), *Promoting Forward Liquidity and Mitigating Market Power in the I-SEM*, 6 April 2014. We submitted this report as an attachment to Energia’s response to I-SEM HLD Consultation SEM-14-008. We also drew the attention of the SEM Committee to the report in subsequent correspondence on 26 August 2014.

⁵⁴ SEM-15-094, table in paragraph 5: “All forward products traded prior to the opening of the Day-Ahead Market (DAM) should be treated as a part of a single relevant (forward) market. The geographic market includes I-SEM and interconnector capacity”.

⁵⁵ SEM-15-094, paragraph 4.3.8.

⁵⁶ SEM-15-094, paragraph 4.3.3.

⁵⁷ SEM-15-094, paragraph 4.3.4.

⁵⁸ SEM-15-094, paragraph 4.3.4.

necessarily imply market power, namely: “collateral requirements”; and “lack of interest by non-asset backed traders” (due to the existence of “better opportunities”).⁵⁹ We do not think that these factors provide sufficient explanation of the difficulties that independent generators and supplier face in forward markets, because market power remains a problem.

The Consultation Paper recognises concerns about ESB’s behaviour in forward markets,⁶⁰ but claims that “the RAs have not seen significant ongoing evidence that forward market power has been exercised in SEM”⁶¹ or that ESB or other participants have behaved (or will behave) in a manner that abuses market power.⁶² We dispute these claims, as explained below.

The RAs propose to introduce a “Forward Contracting Obligation” (FCO), but it is intended to reduce ESB’s incentive to raise prices in the BM and other short term markets. It is not intended to address market power in the forward market.⁶³

With regard to possible MPM measures for forward markets, the RAs mention the role of recent EU regulatory developments, such as MiFid, EMIR and REMIT, and defer to the powers of (unnamed) financial regulatory authorities.⁶⁴ They conclude that “in any event EU financial regulation would appear to be the main instrument to prevent the exercise of forward market power.”⁶⁵

The Consultation Paper therefore proposes no specific MPM measures aimed at the forward markets. It passes on to the Forwards and Liquidity Workstream all responsibility for “the development of liquid physical short-term and forward financial trading in I-SEM”.⁶⁶

More generally, the Consultation Paper does not consider market power within any the other parts of the I-SEM such as the Systems Service Market, Capacity Remuneration Mechanism, Financial Transmission Rights and policies to promote liquidity, stating that “they are out of scope and will be dealt with separately by the respective I-SEM workstreams in a manner which is assumed to deliver efficient outcomes”.⁶⁷

⁵⁹ SEM-15-094, paragraph 7.2.17.

⁶⁰ SEM-15-094, paragraph 7.2.18.

⁶¹ SEM-15-094, paragraph 4.3.6.

⁶² SEM-15-094, paragraph 7.2.18.

⁶³ SEM-15-094, paragraph 8.6.2.

⁶⁴ SEM-15-094, paragraphs 16-26, 2.5.1-4 and 4.3.7.

⁶⁵ SEM-15-094, paragraph 4.3.8.

⁶⁶ SEM-15-094, paragraph 1.2.2.

⁶⁷ SEM-15-094, paragraph 1.2.2.

6.3. Commentary on the RAs' Analysis

We cannot agree that the RAs have seen no evidence of potential market power concerns in the forward market. Energia submitted a report in April 2014 by the independent consultants, Baringa⁶⁸ that concluded:

“Analysis of the current SEM forward market indicates exceptionally low levels of market led liquidity and exhibits dynamics that could be indicative of the exertion of market power.” (P.26)

The report provided evidence to the SEM Committee of ESB's dominant position in the forward market, of the shortfall in ESB's forward contract sales (relative to its generation) and their high price (relative to the price of directed Contracts), and of the problems that that causes for independent suppliers. The report also demonstrates how problems in the forward market could derive from ESB's high market share in generation and retail markets, which could lead to a potential incentive to withhold competitively priced forward contracts from independent third parties to protect market share.

These problems will not be addressed by financial regulation, which only addresses trading behaviour *within* forward markets. The problems that we have brought to the attention of the RAs concern the potential withholding of contracts, i.e. decisions to remain *outside* forward markets

The RAs noted the “lack of interest by non-asset backed traders”,⁶⁹ but did not set out the obvious consequence of this observation. Non-asset backed traders (i.e. financial institutions) are discouraged from entering the market for electricity contracts by the presence of market power and by the need for specific regulatory knowledge. The only players ever likely to enter into electricity forward contracts are those who have a physical position (i.e. generator assets and/or commitments to retail customers). These “asset-backed traders” have risks that they need to hedge over the coming year or two. However, since the supply (i.e. primary sale) of forward contracts is limited to those who own generation assets, the concentration of ownership in the generation market must extend into forward markets, where it creates an additional problem of market power.

By withholding forward contracts from the market, a generator effectively denies one or more independent suppliers the tools they need to hedge price risk. Without access to such tools, those suppliers will be less able to compete against suppliers who have generation assets or who are able to obtain forward contracts. The peculiar position (and incentives) of ESB mean that it is able to extend its market power over generation (which is acknowledged within the Consultation Paper) into market power over forward markets (which the Consultation Paper has failed to address). Energia is strongly of the view that a competitive forward market will not develop organically without regulatory direction and management. The effective

⁶⁸ Baringa (2014), *Promoting Forward Liquidity and Mitigating Market Power in the I-SEM*, 6 April 2014. We submitted this report as an attachment to Energia's response to I-SEM HLD Consultation SEM-14-008. We also drew the attention of the SEM Committee to the report in subsequent correspondence on 26 August 2014.

⁶⁹ SEM-15-094, paragraph 7.2.17.

management of ESB market power must be a central tenant of this regulatory strategy.

The existence of market power within forward markets was drawn to the attention of the RAs in the NERA report of June 2015. In that report, NERA explains how the peculiar status of ESB as a large vertically integrated state-owned company “reduces its requirement to manage risk by trading forward contracts with entities outside the ESB group of companies”.⁷⁰ As a consequence, “by not offering forward contracts, ESB may be preventing independent generators or suppliers from managing their risks and hence from competing effectively in the physical generation and supply markets”.⁷¹

We believe that the MPM Workstream is the proper workstream to deal with this issue. However, if the MPM Workstream decides not to address the problem of market power in forward markets, it must at least ensure that its decision does not prevent other I-SEM workstreams from addressing it.

6.4. Evidence of Market Power in Forward Markets

Energia has pointed out to the RAs on numerous occasions that a liquid forward market is required to facilitate risk management by independent generators and suppliers. Independent generators want to hedge their profit margins by contracting to sell electricity as they contract to buy fuel. Independent retailers want to buy electricity forward contracts to secure the profit margins on their sales to retail customers. As noted by NERA, “market participants trade in the forward market in order to *share* risks. The generator and supplier each provide one another with the service of locking in a specified margin”.⁷²

If energy suppliers are denied access to forward contracts as tools of risk management, they will be unable to “manage their risks to the extent required for them to compete with ESB in markets for generation and supply”.⁷³ In fact, NERA highlights several conditions wherein ESB may prefer not to fully participate in the forward markets such as “reduced sensitivity to commercial risks and their costs”, or a “desire to preserve flexibility over future prices of electricity”. These conditions have, however, an effect on the ability of “others to manager risk and compete effectively”.⁷⁴ A liquid forward market is therefore essential for sustaining and promoting retail competition – and such markets rely on an adequate supply of asset-backed contracts.

The Baringa report of April 2014 described the following conditions suggesting that the supply of such contracts from ESB was insufficient:

⁷⁰ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 4.2, page 10.

⁷¹ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 4.2, pages 10-11

⁷² NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 4.4, page 12.

⁷³ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 4.3, page 11.

⁷⁴ NERA (2015), Review of Market Power Principles for the I-SEM, 18 June 2015, section 4.3, pages 11-12.

- (1) In 2013, ESB had a 39% market share in generation and a 35% market share in electricity supply, so that it was one of the few companies that was “long” in generation;⁷⁵
- (2) ESB was selling less than 60% of its generation volume through forward markets;⁷⁶
- (3) In the market for SEM forward contracts, bid/offer spreads for forward contracts fluctuated around €4/MWh in the SEM, much more than in other countries’ forward markets, whilst SEM trading volumes as a proportion of consumption were much lower than in other countries.⁷⁷
- (4) Non-Directed Contracts (including those sold through auction or via the Tullet Prebon screen) were trading at a substantial premium over the prices in Directed Contracts (which are intended to reflect competitive market conditions).⁷⁸

These indicators have changed little, if at all, since 2013. They provide evidence of potential market power problems in every aspect of the “SCP” framework: (1) concentration in asset-ownership (“Structure”); (2) withholding of asset-backed forward contracts (“Conduct”); (3) and (4) raised prices in SEM forward markets (“Performance”).

The Consultation Paper overlooks these arguments and does not present any evidence to dispel the concerns over the possible exercise of market power in forward markets. As a result, it does not constitute a complete analysis of market power in the forward market. Therefore, the RAs cannot yet rule out the possibility of market power and competition problems arising in forward markets, in a form that falls outside the scope of the financial regulatory authorities.

6.5. New Concerns Under the I-SEM

The I-SEM introduces a new set of markets not currently found in the SEM, namely the secondary markets for capacity that will support Reliability Obligations (ROs). If a generator has a RO, but suffers an outage, its owner will need to buy in capacity from another generator to back the RO. Otherwise, the generator will be exposed to the considerable risk – enough to cause bankruptcy – of high energy prices (and on some occasions Administered Scarcity Prices⁷⁹), leading to high RO settlement payments. Lack of a secondary market in capacity would therefore hinder generators’ ability to compete in I-SEM electricity markets, and in some market designs would threaten the ability to finance their activities (see section 1.2 above).

⁷⁵ Baringa (2014), figures 2-3 and 2-4, page 8.

⁷⁶ Baringa (2014), page 9.

⁷⁷ Baringa (2014), tables 2-2 and 2-3, page 10.

⁷⁸ Baringa (2014), table 2-4, page 11. To provide a relevant comparison, Baringa compares (1) the prices at which Non-Directed Contracts are traded against (2) the prices of Directed Contracts calculated using fuel prices and exchange rates on the dates of the contract trades.

⁷⁹ SEM-15-103, Capacity Remuneration Mechanism: Detailed Design - Decision Paper, paragraph 3.2.93. We note that the current consultation on the CRM leaves open the question as to whether the risk of market participants will be limited through an effective “stop-loss” mechanism. See SEM-15-014, Capacity Remuneration Mechanism: Detailed Design - Second Consultation Paper, paragraph 4.4.14.

This secondary market for capacity represents a new type of forward or financial market, which is not mentioned or analysed in the Consultation Paper. Since all sales of capacity are – by definition – backed by generation assets, this market is also affected by ESB’s large share of capacity and the resulting market power, as measured by the HHI for capacity and the RSI (see section 3.1.3 above). It therefore requires the same attention as other forward markets from the point of view of both market power and liquidity. It is premature for the MPM Workstream to proceed on the basis that other workstreams will deal with such matters “in a manner which is *assumed* to deliver efficient outcomes”.⁸⁰

6.6. *Implications for I-SEM Workstreams*

Presenters at the RA Public Workshop on 15 December 2015 reiterated the plan to refer discussion of forward markets to the “Forward Markets and Liquidity Workstream”. We have several concerns about this proposal, since it may leave unanswered the question of market power and MPM measures in the forward market.

The RAs will have to analyse different trading strategies to decide what volume of forward contracts is required to remove ESB’s incentive to raise prices in physical markets. We presume that the MPM Workstream will co-ordinate this work with the Forwards and Liquidity (F&L) Workstream.

However, the FCO is intended to address market power in physical markets, whilst the F&L Workstream is nominally charged with looking at liquidity. Market participants therefore face the danger that the MPM Workstream will refer all work on forward markets to the F&L Workstream, whilst the F&L Workstream rules out discussion of ESB’s market power in forward markets, on the grounds that it falls within the remit of the MPM Workstream.

Such lack of co-ordination in administrative procedures is not uncommon. It would swiftly convert the overlap between the two workstreams into a giant gap in the I-SEM program.

The same problem arises over market power in secondary capacity markets, with the added complication that it has been formally excluded from the MPM Workstream, without being assigned to the work programme of any other specific workstream.⁸¹

6.7. *Vertical Ring-Fencing*

We cannot immediately see why the introduction of new electricity trading rules would raise a question about vertical ring-fencing, since it responds to structural factors that are unaffected by the proposed changes. However, given that the question has been raised, we reiterate here our view, stated in previous responses to consultations, that vertical ring-fencing has a role to play in the control of market power and in promoting a competitive and liquid forward market.

⁸⁰ SEM-15-094, paragraph 1.2.2, italics added.

⁸¹ SEM-15-094, paragraph 1.2.2, says only that they will be “dealt with separately by the respective I-SEM workstreams in a manner which is assumed to deliver efficient outcomes”.

Of course, the RAs should impose ring-fencing obligations based on an assessment of appropriate metrics – e.g. market shares – rather than based on the status of a particular company as a “legacy incumbent”. However, taking these metrics into account (see above), we would strongly oppose any proposal to remove the ring-fencing obligation from ESB.

All current evidence indicates a continuation of the problems that led to the imposition of vertical ring-fencing in the first place. This evidence includes matters raised in the Consultation Paper and discussed in earlier sections of this response. Specifically, ESB continues to cause concern due to its high market share, increasing pivotality, growing market power, and (“asset-backed”) influence over forward markets. (See sections 3.1 and 6.4 above.)

We therefore believe it would be absurd to regard a reform of the electricity market rules as sufficient justification for removing the obligation to adopt vertical ring-fencing on ESB. Indeed, it seems imprudent, or even reckless, to make such a significant change in the structure of the market before accruing evidence on market operation under the new rules and MPM measures.

It is therefore appropriate that a targeted obligation to adopt vertical ring-fencing continues to apply to ESB at least. It would require novel and compelling arguments to justify removing this obligation and none has been advanced.

6.8. Conclusions

The Consultation Paper overlooks crucial arguments about market power in the forward market and presents no evidence to dispel the resulting concerns. As a result, the Consultation Paper does not constitute a complete analysis of market power in the forward market. **The RAs cannot yet rule out the possibility of market power and competition problems arising in forward markets, in a form that falls outside the scope of the financial regulatory authorities.**

Given these considerations, the MPM Workstream will not have completed its task properly, and cannot safely hand over all consideration of forward markets to the F&L Workstream, until it is agreed formally that the F&L Workstream will cover all matters relating to liquidity in forward markets, including matters of market power delegated from the MPM Workstream. These matters cover the following topics, among others:

- ESB’s market power over risk management through asset-backed forward contracts and its implications for competition in the retail sector;
- ESB’s market power over capacity and the implications for liquidity in secondary markets for capacity to support Reliability Obligations and competition in the generation market;
- The role of Vertical Ring-Fencing in contributing to a reduction in ESB’s market power over risk management and asset-backed forward contracts.

If the MPM Workstream wishes to refer on all future work on forward markets, it is of paramount importance that the SEM Committee confirms a new mandate for the Forwards and Liquidity Workstream that addresses these matters. At a minimum, the SEM Committee should confirm that the Forwards and Liquidity Workstream (1) will address all concerns raised over forward (and capacity) markets, including all relevant aspects of electricity sector structure, ESB's conduct and market performance, even if these considerations subsequently point to the existence of market power, and (2) will not in any circumstances refer the question back to the MPM Workstream. Any division of these tasks between multiple Workstreams should be confirmed equally explicitly.

Without such confirmation, there is every possibility that the I-SEM Workstreams will not give proper consideration to (1) market power in forward and capacity markets and (2) the promotion of competition in generation and retail supply of electricity.

7. List of Consultation Questions

For ease of reference, we set out below the list of questions in the Consultation Paper, with their links to relevant sections of this document in square brackets.

Section 2: Context For Market Power Policy Development

- Do you agree with the policy developments and trends identified (above) as potentially impacting on an I-SEM market power mitigation strategy?
- Are there other factors not identified here which you consider relevant?

The Consultation Paper does not consider the risks arising from ESB's state ownership and the implications for market power mitigation. As a state-owned entity, ESB is not subject to the same commercial discipline as privately owned firms. Accordingly, the choice of MPM measures should pay particular attention to guarding against the risk of anti-competitive predation. For further discussion, see section 4.4: Competitive Prices in Complex Markets, in particular section 4.4.2.

The Consultation Paper does not examine in detail possible MPM measures in forward markets, on the basis that such matters either lie within the responsibility of financial regulators or fall to future discussion in the Forwards and Liquidity (F&L) Workstream. However, The RAs cannot yet rule out the possibility of market power and competition problems arising in forward markets, in a form that falls outside the scope of the financial regulatory authorities.

Given these considerations, the MPM Workstream will not have completed its task properly, and cannot safely hand over all consideration of forward markets to the F&L Workstream, until it is agreed formally that the F&L Workstream will cover all matters relating to liquidity in forward markets, including matters of market power delegated from the MPM Workstream. For further discussion see section 6: The Forward Market.

Section 3: Relevant Geographic Market(s) And Trading Period(s)

- Do you agree with the proposed appropriate markets/trading periods for assessing market power in I-SEM's energy and financial markets?

The definition of relevant markets follows conventional guidelines, by focusing on half-hours and other short periods. However, the review of market data uses the HHI for annual generation, which is not a relevant market. The indications provided by this statistic are misleading (since they capture a number of opposing trends) and should be ignored. The RSI and the HHI for capacity show more accurately how market power will develop. See section 3.1: HHI and RSI as the Main Indicators.

- Do you agree with the proposed geographic scope of the proposed markets/trading periods?

The Consultation Paper proposes market definitions and trading periods by which the relevant markets may be geographically narrow and short-lived, particularly for localised markets for resolving transmission constraints during

particular hours. It will take some time – and sometimes may not be practical at all – to manage such services by negotiating contracts with the system operator. In the meantime, generators must survive on their revenues from the BM. Restricting bids and offers in such localised markets, by tying them to SRMC, would damage the ability of licence-holders to finance their activities and their incentive to keep plant available to the system. For further discussion of these problems, see section 5.2.4: Limits on the role of contracts.

Section 4: I-SEM Design, Interactions And Implications

- Do you agree with the proposed definition of competitive behaviour and pricing in I-SEM?

Only within the theoretical abstraction of a perfectly competitive atomistic market do producers set prices equal to their own SRMC. In practice, in electricity markets with start-up costs and other fixed costs (economies of scale), a competitive market outcome is consistent with a generator setting its offer price above its SRMC, because the competitive market price lies above the SRMC of the most expensive generator running at the time. The RAs would therefore be imposing non-competitive outcomes if they forced generators to offer or to accept a price tied to SRMC for regulatory purposes. For further discussion of the theory of competitive pricing, see section 4: SRMC as the Target for “Competitive” Pricing.

Any MPM measures designed to restrict offer prices must allow the system operator to purchase the output of transmission-constrained generators at prices which (1) cover all the associated costs, (2) maintain the incentive to produce and (3) allow market participants to achieve an efficient outcome. In particular, rules that prescribe a formula for SRMC pricing may deny consumers access to the support that generators provide to the network in transmission-constrained areas. For further discussion of this problem, see section 5: Specific Problems with SRMC Pricing for Transmission Constrained Generation.

- Do you think that the suggested examples in which market power can be exercised in I-SEM captures the relevant issues?

The examples in the Consultation paper narrowly interpret the exercise of market power as pricing above a generator’s own SRMC. This narrow focus increases the risk of Type 1 and Type 2 errors. In practice, generators may price *above* their own SRMC in competitive markets, so imposing SRMC would represent over-regulation (a Type 1 error). See sections 4: SRMC as the Target for “Competitive” Pricing, and 5: Specific Problems with SRMC Pricing for Transmission Constrained Generation.

On the other hand, generators may behave anti-competitively by pricing *below* SRMC. ESB has a dominant position and, as a state-owned entity, is not subject to the same commercial pressures as privately owned companies, which suggests that predation may be a particular risk in the I-SEM. Allowing offer prices below a prescribed level of SRMC (as suggested in paragraph 8.7.5 of the Consultation Paper) would then represent under-regulation (a Type 2 error). See section 4.4.2: Predatory pricing.

These examples demonstrate the need for discretion (to be applied according to clearly defined principles) when defining and applying MPM measures.

- Do you agree that the potential for market power abuse in I-SEM appears to be weaker in the forward financial market compared to the physical markets?

No. We think that ESB's dominance and vertical integration provide it with additional levers to exercise its market power by denying access to hedging products. The RAs should consider this risk separately from the prompt market, either as part of this workstream or as a clearly delegated task for the F&L workstream. For further discussion, see section 6: The Forward Market.

- Do you agree with the implications for market power arising from interactions between the physical markets, CRM, FTRs and DS3 System Services as shown above?

Through arbitrage, pricing in the BM ought to dictate prices in other "derivative" markets, including DA, ID and forward markets. The application of MPM measures to these "derivative" markets therefore requires consideration of factors other than simply SRMC at the time of a trade. For further discussion of the role of SRMC in derivative markets, see section 4.5: Application to DA and ID Markets.

The overall package of market rules and MPM measures must comply with legal requirements, including the obligation to allow licensees to finance their activities, which requires that they can cover their costs. For a discussion of this topic in general and in relation to transmission-constrained generators, see sections 1.2: Legal Requirements and 5: Specific Problems with SRMC Pricing for Transmission Constrained Generation.

Although forward contract pricing should in principle reflect expected prices—and hence market power—in the BM, there is considerable scope for market power to arise separately in forward markets, because of the reliance on asset-backed traders. (The Consultation Paper notes this reliance in paragraph 7.2.17, but does not spell out its implications.) ESB's dominance of generation extends into the forward market, because of this link between assets and contracting, which represents a barrier to entry. Any reluctance on ESB's part to trade forward contracts hampers the ability of independent third parties to manage their risks and, hence, to compete in physical markets for generation and retail supply of electricity. For further discussion of this point, see section 6: The Forward Market.

Section 5: Relevant I-SEM Metrics

- Do you agree that these are the appropriate metrics to identify market power ex-ante and ex-post in I-SEM?

The HHI for "annual generation" does not correspond to any of the relevant markets defined earlier in the Consultation paper, which are half-hourly or perhaps daily. Measures of HHI derived from it are therefore unrelated to any particular market and potentially misleading.

By comparison, the HHI for capacity and the RSI describe the situation in physical markets in high stress periods, i.e. at times of moderate-to-high demand, with low wind output. These are the periods when market power is

most likely to be a problem, so these indicators provide the most informative basis for filtering candidates and for targeting MPM measures. For further discussion, see section 3.1: Identification of Candidates for MPM Measures.

- Are there other metrics that you consider should be applied?

An “effective” filter does not only identify market participants that have market power, but also excludes market participants that provide competitive pressure. The Consultation Paper recognises the “SCP” framework (in para 5.1.2), but concentrates on Structural data as the basis for defining filters. These filters will give misleading indications about the market (Type 1 and Type 2 errors), unless augmented by consideration of Conduct and Performance.

For discussion of filters for Conduct and Performance, see section 3: Identification of Candidates for MPM Measures and section 6: The Forward Market.

Section 6: Estimate of I-SEM Market Power

- Do you agree with the approach taken by the RAs to modelling market power in I-SEM?
- Do you agree with the conclusions for I-SEM market power that have been drawn from the modelling results?

The HHI for “annual generation” does not correspond to any of the relevant markets defined earlier in the Consultation paper, which are half-hourly or perhaps daily. Measures of HHI derived from it are therefore unrelated to any particular market and potentially misleading.

By comparison, the HHI for capacity and the RSI describe the situation in physical markets in high stress periods, i.e. at times of moderate-to-high demand, with low wind output. These are the periods when market power is most likely to be a problem, so these indicators provide the most informative basis for filtering candidates and for targeting MPM measures.

See section 3: Identification of Candidates for MPM Measures, particularly section 3.1: Identification of Candidates for MPM Measures.

Section 7: Review of Current SEM Measures

- Do you agree with the SEM Committee’s view on the effectiveness of each of the SEM market power mitigation measures?

In the Consultation Paper, the SEM Committee expresses its view that the current MPM measures have been successful. The success of the BCOP, in particular, has relied on using a principles-based approach, rather than prescriptive formulae, for regulating offer prices.

For further discussion of our views, see section 2: Review of Current MPM Measures.

- Are there any particular aspects of the SEM market power mitigation strategy that you think should be applied differently, especially in relation to I-SEM?

Changes to the bid formats available to participant under I-SEM energy trading arrangements mean more flexibility than is currently allowed under the BCoP will be required. For further discussion of this point, see section 2: Review of Current MPM Measures, particularly section 2.1.2: New problems arising from the design of the I-SEM Energy Trading Arrangements.

Section 8: SEM Mitigation Strategy and Measures

- Do you agree with the five key principles for assessing market power mitigation policies as outlined in this section 8.3? If you think there should be alternatives, please state the reasoning.

The Consultation Paper lists five key principles to be used “as the basis for assessing various market power mitigation policies.”⁸² These key principles encompass useful decision-making criteria, but they are subject to a wide range of possible interpretations. To provide a practical guide to decision-making, these key principles must be considered in conjunction with the legal requirements arising from compliance with the statutory duties of the RAs and with the general principles of European law and Irish constitutional and administrative law. When applying these principles, it will also be necessary to avoid the two types of error also set out in section 8.3 of the Consultation Paper (para 8.3.3).

In this response we have provided detailed comment on the five key principles, taking into account both the wider legal framework and the need to minimise both “Type 1” and “Type 2” errors. We have also stressed the importance, from a market participant perspective, of MPM measures meeting the transparency criterion, without which market participants will not be prepared to exploit competitive opportunities and competition will suffer.

For further discussion of our views on these principles, see our review of appraisal criteria in section 1.3: Key Principles.

- For the Forward Contracting Obligation:
 - What should be the measure and threshold that results in a market participant being included or excluded in the FCO, i.e. what is its applicability?
 - What should be the volume and product definition of forward contracting required from a market participant who falls under the FCO?
 - How should the price be set for the volume contracted under the FCO?
- What type of access should buyers have to FCO volumes?

There is considerable scope for market power to arise separately in forward markets, because of the reliance on asset-backed traders. (The Consultation Paper notes this reliance in paragraph 7.2.17, but does not spell out its implications.) ESB’s dominance of generation extends into the forward market, because of this link between assets and contracting, which represents a barrier to entry. Any reluctance on ESB’s part to trade forward contracts

⁸² SEM-15-094, paragraph 8.3.1.

hampers the ability of independent third parties to manage their risks and, hence, to compete in physical markets for generation and retail supply of electricity.

The discussion of FCO volumes is not independent of the consideration of liquidity by the F&L Workstream. Independent generators and suppliers require access to forward contracts for the purpose of risk management. The same requirements of risk management tie the supply of forward contracts to the ownership of assets. Any generator who is dominant in the market for generation therefore needs to be obliged to offer contracts for (at least) the volume of its expected output, and to offer such contracts on a non-discriminatory basis to independent third parties (not just to its own retailing businesses).

If consideration of these requirements is to be taken up by the F&L Workstream, it is imperative that the MPM Workstream does not shut off the possibility of considering market power (as well as liquidity) in forward markets.

For further discussion of these points, see section 6: The Forward Market.

Having made these general comments, we respond to the questions raised about forward contracting obligations (FCOs) more specifically below:

Forward Contracting Obligations

Experience from SEM indicates that a competitive forward market will not develop organically in I-SEM without direct regulatory intervention because of the underlying structural issues in the market (notably ESB market dominance). We note that liquidity on the current OTC screen remains poor with low trade volumes and uncompetitive pricing on product offerings. We furthermore note Baringa's conclusion that such dynamics

"...could be indicative of the exertion of market power." (P.26)

The exertion of market power in the forward market could undermine the conditions for effective retail competition and result in inefficient retail customer pricing levels, regardless of spot market liquidity levels. It is therefore essential that there are effective measures introduced to mitigate the capability of any participant to exert market power in the I-SEM forward contract market.

- What should be the measure and threshold that results in a market participant being included or excluded in the FCO, i.e. what is its applicability?

FCOs should be used to mitigate market power in both spot and forward market timeframes. A market participant's inclusion under the FCO should be determined with reference to their capability to exert market power in: 1) I-SEM spot markets; and 2) the I-SEM forward contract market. For details on our views regarding the assessment of market power under 1) see section 3 of this response and under 2) see section 6.

- What should be the volume and product definition of forward contracting required from a market participant who falls under the FCO?

Energia recommends that FCO volumes are set at a level that is sufficient to manage market power in both the forward and spot market timeframes, rather than with reference to the spot market only. Any generator who is dominant in the market for generation (such as ESB) should therefore be obliged to offer contracts for (at least) the volume of its expected output, and to offer such contracts on a non-discriminatory basis to independent third parties (not just to its own retailing businesses).

In terms of the form of contracts offered under the FCO, Energia would welcome consideration of the following design features. These would help align contract product offerings with the risk management requirements of suppliers.

1. Volumes sold up to 27 months in advance – e.g. a 3 month lead time with a trading horizon spanning 24 months. Extending the duration of the trading horizon will facilitate suppliers to implement hedging strategies and will also help in the development of a forward curve for the I-SEM.
2. Fixed eligibility for the 24 month trading window to provide certainty to suppliers of their FCO contract eligibility. This will provide support to retail competition by providing more certainty in relation to available hedging products and thereby facilitate planning of retail hedging strategies by suppliers.
3. Similar cumulative laddered approach to volumes offered in each FCO contract round but with monthly products being offered for the first 6 months of the trading horizon with quarterly products sold for the period thereafter. This would allow suppliers to better manage month to month changes in consumption.
4. Provision of mid merit 2 products and less emphasis on mid merit 1 product. Increasing product alignment with GB contract types could help incentivise GB players to participate in the I-SEM forward market, particularly if exchange based trading were developed.

Energia would also emphasise that PSO backed CfD contracts also provide essential access to hedging instruments for suppliers and we therefore recommend that they are maintained in the I-SEM given the liquidity issues. To better align PSO contract offerings with the risk management requirements of suppliers we suggest the following changes to their current format.

1. Contracts are sold up to 15 months in advance – e.g. a 3 month lead time with a trading window spanning 12 months. Extending the duration of the trading horizon will facilitate suppliers to implement hedging strategies and will also help in the development of a forward curve for the I-SEM.
2. Contract volumes fixed for the 12 month trading window to provide certainty to suppliers of contract availability. This will provide support to retail competition by providing more certainty in relation to available hedging products and thereby facilitate planning of retail hedging strategies.
3. Similar cumulative laddered approach as FCO contracts process in each PSO contract round but with monthly products being offered for the first 6

months of the trading horizon with quarterly products sold for the period thereafter. This would allow suppliers to better manage month to month changes in consumption.

- How should the price be set for the volume contracted under the FCO?

Energia would welcome further consideration and debate around possible approaches to the sale and pricing of FCO contracts and PSO backed contracts that could help promote wider liquidity in the I-SEM forward market. A potential option is to sell such contracts through an exchange or trading screen in designated liquidity windows. For such an approach to work the RAs would need to set a price cap for the forward contracts offered, but the approach would allow the market to establish the traded price. In the case of FCO contracts, a volume cap (based on participant eligibility), could be imposed on participants, that could apply across a predefined time period. Further discussion on the specifics of how this could be implemented could be conducted as part of the forward and liquidity workstream but the approach should encourage liquidity pooling and may help promote more competitive dynamics on the bid side of the market, while providing robust regulation of the offer side (where there is a lack of competition due to structural issues).

We note there could also be potential synergies between the approach proposed above and mitigation measures that are required to deliver a liquid, competitively priced secondary market in ROs, including volume obligations on dominant participants, measures to ensure competitive pricing and a centralised exchange or trading platform.

Energia would strongly emphasise, however, that regardless of the approach taken to the sale of FCO and PSO backed contracts, effective, comprehensive regulatory monitoring and reporting on I-SEM forward market trading dynamics is required to re-enforce self-correcting behaviour and help ensure that the conditions necessary to maintain retail competition are maintained in the I-SEM forward market.

- Which of the balancing market mitigation options do you consider most appropriate, i.e. MMU-triggered intervention, automated intervention via a PST or via the “flagging and tagging” approach, or prescriptive bidding controls? Where feasible please relate the preferred approach the five key principles for this workstream of effective, targeted, flexible, practical and transparent.

We do not consider any of the proposed options for the Balancing Market to be at all suitable to conditions in the I-SEM or to be consistent with applicable legal requirements. They would all impose prescriptive formulae based on SRMC, which would prevent market participants from setting competitive prices, from providing useful pricing signals and from financing their activities. Prescriptive rules on SRMC pricing are accordingly not an option that is open to the RAs. A practical and effective MPM measure, that minimises both Type 1 errors and Type 2 errors, must couch restrictions on bidding or pricing in terms of principles (similar to, or adapted from, those in the BCoP). That applies as much to the BM as to any other market in the I-SEM.

Thus, only a principles-based approach to mitigating market power holds any prospect of promoting competition in the Balancing Market and of being compliant with applicable legal requirements. We support Option 4 as proposed for the DA and ID markets and also consider this the only appropriate MPM measure for the Balancing Market. As discussed in section 1.3, a requirement for transparency applies to this and all other principles-based options, and hence there is a need for some published guidelines on what constitutes prohibited behaviour.

We note that the RAs have effectively rejected the possibility of applying prescriptive formulae to the DA and ID markets.⁸³ Precisely the same arguments as those used in relation to the DA and ID markets apply to the BM. At the RA Public Workshop held in Dundalk on 2 December 2015, panel members even stated in response to a question that the omission of any principles-based option was a “drafting oversight”.

We believe that having regard to the significance of this matter, it would have been appropriate and consistent with the RA's obligation of transparency that a clarification be published and we requested that the RAs do so in our letter of 23 December 2015. In the RAs' letter of 15 January 2016, the RAs acknowledge a level of ambiguity in the Consultation Paper but disappointingly say that no clarification is required, and furthermore that “it is clear that the SEM Committee does not consider Option 4, the least interventionist of the options in the DAM and IDM as appropriate for the BM”. For the avoidance of doubt, we do not believe that any explanation, let alone a satisfactory explanation, is offered in the Consultation Paper why “Option 4” should not even be *considered* for the BM. In any event, the letter continues to say that “There is also scope of for these [ex ante bidding] principles to apply to the energy actions in conjunction with a number of BM options, such as option 1 and 2 (A and B)”.

We therefore assume, consistent with the RAs' obligations, that flexible options in respect of the BM have not been ruled out and that the final decision on MPM Measures will at least consider – and, in the light of the evidence, adopt – a principles-based approach to mitigating market power in the BM.

The interpretation of any future bidding principles must be flexible enough to deal with all future cases and objective or transparent enough to give market participants clarity over what competitive behaviour is allowed, as well as what abuses are prohibited. The criteria used for applying them – whether ex ante or ex post – must therefore be defined clearly in advance. The implications for appraisal criteria are set out in our review of the RAs' proposed principles, in section 1.3: Key Principles.

For further discussion of these points, see section 4: SRMC as the Target for “Competitive” Pricing, and section 5: Specific Problems with SRMC Pricing for Transmission Constrained Generation.

- Which ex-ante bidding/offer market power mitigation options for the DA and ID markets do you favour – bidding principles and ex-post assessment, or ex-post assessment only? Where feasible please relate

⁸³ SEM-15-094, paragraph 8.9.7

the preferred approach to the five key principles for this workstream of effective, targeted, flexible, practical and transparent.

Prescriptive rules on SRMC pricing will not promote efficient competition, are wholly inconsistent with applicable legal requirements including constitutionally protected rights of property, and will deny consumers the services they require. Prescriptive rules on SRMC pricing are accordingly not an option that is open to the RAs.

Applying bidding principles to the DA and ID markets will require an additional degree of discretion and interpretation, because competitive prices in these “derivative” markets will depend on expected prices in the BM, not on the SRMC at the time of a trade.

The interpretation of any future bidding principles must be flexible enough to deal with all future cases and objective or transparent enough to give market participants clarity over what competitive behaviour is allowed, as well as what abuses are prohibited. The criteria used for applying them – whether ex ante or ex post – must therefore be defined clearly in advance. The implications for appraisal criteria are set out in our review of the RAs’ proposed principles, in section 1.3: Key Principles.

Energia supports Option 4 as proposed for the DA and ID markets. A requirement for transparency applies to this and all other principles-based options, and hence there is a need for some published guidelines on what constitutes prohibited behaviour.

Energia also recommends that effective mitigation of the dominant entity’s market power across all I-SEM and DS3 markets must be the primary focus of the market power mitigation strategy to help develop the conditions required to support effective competition under I-SEM and DS3.

For further discussion of these points, see section 4: SRMC as the Target for “Competitive” Pricing and in particular section 4.5: Application to DA and ID Markets.

- If ex-ante bidding principles were to be adopted, how flexible should they be and how would this be facilitated/enshrined in their wording?

The interpretation of any future bidding principles must be flexible enough to deal with all future cases and objective or transparent enough to give market participants clarity over what competitive behaviour is allowed, as well as what abuses are prohibited. The criteria used for applying them – whether ex ante or ex post – must therefore be defined clearly in advance. The implications for appraisal criteria are set out in our review of the RAs’ proposed principles, in section 1.3: Key Principles and section 4: SRMC as the Target for “Competitive” Pricing.

- Under what structural conditions or in combination with other market power mitigation measures should vertical ring-fencing of the incumbents be relaxed?

Vertical ring-fencing has a role to play in the control of market power and in promoting a competitive and liquid forward market. The RAs should impose ring-fencing obligations based on an assessment of appropriate metrics – e.g. market shares – rather than based on the status of a particular company as a

“legacy incumbent”. However, taking these metrics into account (see above), we would strongly oppose any proposal to remove the ring-fencing obligation from ESB.

Based on all current evidence it would be absurd to regard a reform of the electricity market rules as sufficient justification for removing the obligation to adopt vertical ring-fencing on ESB. Indeed, it seems imprudent, or even reckless, to make such a significant change in the structure of the market before accruing evidence on market operation under the new rules and MPM measures.

It is therefore appropriate that a targeted obligation to adopt vertical ring-fencing continues to apply to ESB at least. It would require novel and compelling arguments to justify removing this obligation and none has been advanced.

See section 6: The Forward Market, and in particular section 6.7: Vertical Ring-Fencing.

- Under what circumstances and criteria (or metrics) should the application of ring-fencing to other market participants be considered?

Vertical ring-fencing has a role to play in the control of market power and in promoting a competitive and liquid forward market. The RAs should impose ring-fencing obligations based on an assessment of appropriate metrics – e.g. market shares – rather than based on the status of a particular company as a “legacy incumbent”. However, taking these metrics into account (see above), we would strongly oppose any proposal to remove the ring-fencing obligation from ESB.

Based on all current evidence it would be absurd to regard a reform of the electricity market rules as sufficient justification for removing the obligation to adopt vertical ring-fencing on ESB. Indeed, it seems imprudent, or even reckless, to make such a significant change in the structure of the market before accruing evidence on market operation under the new rules and MPM measures.

It is therefore appropriate that a targeted obligation to adopt vertical ring-fencing continues to apply to ESB at least. It would require novel and compelling arguments to justify removing this obligation and none has been advanced.

See section 6: The Forward Market, and in particular section 6.7: Vertical Ring-Fencing.