Integrated Single Electricity Market (I-SEM)

I-SEM Market Power Mitigation

Consultation Paper

SEM-15-094

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Table of Contents

EXECUTIVE SUMMARY

Introduction

1. The SEM Committee's High Level Design (HLD) on the Integrated Single Electricity Market (I-SEM)[1] of September 2014 highlighted the need to develop any additional measures to ensure that electricity consumers are protected from market power abuse. Since then the Regulatory Authorities or RAs – the CER and Utility Regulator – have progressed an I-SEM market power mitigation workstream, with an introductory Discussion Paper published in May 2015, and a follow-up paper summarising responses issued in August 2015[2].

2. Taking account of comments received to the Discussion Paper, the RAs are publishing this SEM Committee Consultation Paper on the market power mitigation strategy and measures for the I-SEM wholesale energy markets, to apply from I-SEM go-live. This is with the aim of mitigating the incentive and ability of any market participant to exercise market power in the I-SEM physical and financial markets.

Stakeholder Engagement

3. Comments to this Consultation Paper, including answers to questions posed at the end of various sections, are requested from stakeholders by 18th January 2016, to be sent in electronic format to both Gonzalo Saenz at the CER at gsaenz@cer.ie and Joe Craig in the Utility Regulator at joe.craig@uregni.gov.uk.

4. The RAs will hold a public workshop to discuss this consultation, in order to explain its proposals and to allow stakeholders to air their views. This workshop will be held in the Crowne Plaza Hotel in Dundalk on Wednesday 2nd December 2015, from 14:00 to 17:00.

Relevant Markets

5. The three main dimensions commonly used to define relevant markets for assessing market power in the electricity sector are product, geography and time**.** The intersection of these three dimensions is used to propose relevant markets/trading periods for market power assessment in I-SEM shown in the following table.

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[1] Please see: http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f

[2] Please see: http://www.allislandproject.org/en/market_current_consultations.aspx?article=9c34c90d-38ea-4dee-b0de-adeed6726ea0&mode=author

Relevant I-SEM Market	Definition
Forward	• 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.
Day-Ahead Market	• Electricity is traded as an hourly product for the next day without consideration for transmission and generator operational constraints. • The geographic market includes I-SEM and interconnector capacity.
Intra-Day Market	• The Intra-Day Market (IDM) product is similar to the DAM though there are some operational differences. • The geographic market includes I-SEM and interconnector capacity.
Balancing Market	• Electricity in the Balancing Market (BM) will be traded as a half-hourly product, taking into account transmission as well as operational constraints. • The largest possible size of the geographic market will be the I-SEM and interconnector capacity (as with the DA and ID markets). • The smallest geographic market may be as small as a constrained area consisting of a single generator.

Relevant Metrics

6. The structure-conduct-performance (SCP) paradigm is used to provide a market power analysis framework. Its three main components are:

- Structure - refers to the established market structure, such as market shares, market concentration, or the pivotality of suppliers, that may influence market participants' ability and incentive to exercise market power;
- Conduct or behaviour - whether market participants engage in economic or physical withholding or other forms of non-competitive behaviour; and,
- Performance - whether market performance (e.g., market prices, price mark-ups, net revenues, liquidity) is affected by market participants' non-competitive conduct.

7. Often it is necessary to assess these three SCP components jointly. A market may not be structurally competitive but market participants may behave in a competitive manner and thus market performance may be competitive. The reverse may be true too. The SEM Committee therefore propose to use a combination of metrics to measure market power in the relevant markets/trading periods. This is detailed in section 5 and includes market share, RSI, HHI, mark-up indices (with respect to SRMC - see later), withholding analyses, net revenue and liquidity measures.

Market Power Modelling

8. Modelling has been undertaken by the RAs to assess, at a high-level, the potential for structural market power in I-SEM for selected years over the coming decade, though

of course market conduct and performance (as per the SCP paradigm) also need to be considered in developing an I-SEM market power mitigation strategy.

9. The modelled results by installed capacity and generation output are summarised in the following table. It can be seen that ESB remains the largest player; its capacity share increases up to 2024 due to plant closure by other players, but its generation market share falls significantly from circa 47% in 2016 to 30% in 2024 as wind generation increases.

	Capacity market share, DA			Generation market share, DA		
Market participant	**2016**	**2019**	**2024**	**2016**	**2019**	**2024**
ESB	44.4%	46.1%	52.3%	46.6%	42.0%	30.3%
SSE	13.5%	14.0%	8.4%	14.1%	14.9%	19.1%
AES	13.2%	8.1%	3.2%	7.2%	5.7%	0%
BGE	4.7%	4.9%	5.6%	7.0%	7.8%	12.5%
GB import	n/a	n/a	n/a	5.9%	8.8%	11.7%
Independent Wind	n/a	n/a	n/a	6.7%	8.1%	9.6%

10. Even though ESB's generation market share and overall market concentration is expected to fall, the potential for exercising market power at certain times is likely to increase. This is shown in the table below where ESB's RSI is below 1.2 circa 9.1% of the time in 2016, increasing to 37.5% in 2024. A similar trend can be seen for the 2-pivotal supplier (2PS) test. This is due to increasing intermittent wind generation, the expected reduction in non-ESB conventional generation capacity and higher demand. It means that, in periods of low wind generation, the potential for one or more market participants to exercise market power increases.

	% half hourly periods, DA					
	RSI < 1.2			RSI < 1		
Company	**2016**	**2019**	**2024**	**2016**	**2019**	**2024**
ESB	9.1%	12.5%	37.5%	0.7%	1.3%	13.9%
SSE[3]	0.0%	0.0%	0.02%	0.0%	0.0%	0.00%
2PS[4]	40.6%	40.4%	54.8%	15.4%	16.2%	30.8%

11. The two main metrics of structural market power, the HHI and the average RSI, have similar diverging results as per the following table. The rising share of wind generation and ESB's lower generation market share results in a falling HHI between 2016 and 2024, indicating lower market concentration and a decline in market power overall. However, when looking at the average RSI, ESB's average RSI falls, as a result of increased volatility due to the greater wind capacity and the exit of stations from other companies, which indicates increasing market power concerns at certain times.

[3] As well as ESB, the table show the RSI of the second largest market participant by generation market share. This is SSE for 2016, 2019 and 2024.

[4] 2PS is the combined RSI of the two largest market participants in each half-hourly period.

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

12. This modelled divergence between a reducing HHI such that the market could be considered only moderately concentrated by 2024, and yet a decreasing average RSI (indicating increased potential for market power at certain times only), needs to be taken into account when developing an I-SEM market power mitigation strategy.

13. Due to the nature of market conditions in the balancing market, different generators will be available to meet demand in different periods. In the following table the RSI of the largest player (1PS) in each period of the balancing market is reported as well as the RSI of the two largest players (2PS). For example, the results indicate that in 2019, the largest capacity holder in each period will be pivotal 62.2% of the time, with the two largest players pivotal 89.7% of the time. This suggests that a robust market power mitigation strategy will be particularly important in the balancing market.

BM - Market participant	2016	2019	2024
1PS	64.9%	62.2%	72.8%
2PS	87.5%	89.7%	94.9%

14. In addition to the structural market power of the larger market players discussed above, the modelling has also identified that smaller participants can have the incentive and ability to exercise market power at certain times of the year, which again needs to be considered in any I-SEM market power mitigation strategy.

Current SEM Measures

15. The following is the SEM Committee's view with respect to the current market power mitigation measures in SEM. This forms a backdrop for the proposed I-SEM market power mitigation measures referred to next.

- Market Monitoring Unit - the MMU function of the RAs has worked well in SEM, especially in monitoring and enforcing BCoP.
- Bidding Code of Practice - the current BCoP has been effectively enforced, and it has likely prevented market power abuses. Combined with the MMU it has helped ensure that wholesale pricing in SEM has been set at the appropriate Short-Run Marginal Cost (SRMC) level.
- Directed Contracts - DCs have reduced ESB's and PBB's (when applicable) incentive to exercise market power in the spot market and have therefore been an effective measure to address concerns about structural market power.
- Vertical ring-fencing - the general view is that vertical ring-fencing of ESB and Viridian has been effective working alongside other market power mitigation measures.

I-SEM Market Power Mitigation Measures

Context for Measures

16. The SEM Committee's focus is on competitive outcomes and market power mitigation options with respect to the relevant I-SEM physical markets. The forward market is primarily a matter for EU financial regulations and regulators, though of course the RAs will co-operate with the financial regulatory authorities to the appropriate extent.

17. The SEM Committee uses SRMC pricing/outcomes, which may include administered scarcity pricing if introduced, as a key competitive benchmark for efficient outcomes in I-SEM. This is compatible with the commercial objective of efficient generator owners recovering both fixed and variable costs, via a combination of inframarginal rents in the physical markets and capacity payments among others. Hence the SEM Committee considers an outcome for the physical energy markets that deviates from the SRMC benchmark as a potential exercise of market power.

18. The SEM Committee notes that there are a range of ex-post measures available to monitor the conduct and performance of the physical energy markets with respect to this benchmark. These include the Market Monitoring activity of the RAs, discussed next. REMIT also gives ACER and the RAs the ability to assess transaction data in I-SEM for compliance with REMIT's market rules, and the RAs can take ex-post action under REMIT and existing ex-post competition powers.

RA Market Monitoring

19. The modelling results show that there will continue to be a level of aggregate structural market power in I-SEM to 2024, while there will also be ability for participants to exercise market power for other reasons, for example due to local transmission system constraints. Furthermore, international experience suggests that there is a continued need for proactive market monitoring even as electricity markets become more competitive. In light of this, the SEM Committee believes that, for the foreseeable future at least, there will be a need for robust Market Monitoring activity of the RAs as a strong ex-post market power mitigation measure in I-SEM.

20. To facilitate this, the NEMO for DA and ID markets and market operator for the BM and imbalance settlement will be required to provide timely market data to the RAs for analysis. This will be in addition to any surveillance of the relevant markets that they will carry out themselves. The RAs will also be able to access data collected by ACER under the auspices of REMIT. In carrying out their market monitoring and enforcement activities, the RAs will:

- Determine what constitutes competitive offers in the I-SEM physical trading periods, i.e. to the extent that that they are consistent with SRMC pricing/outcomes;

- Monitor the conduct of market participants and the overall performance of the market in the various I-SEM physical trading periods, including compliance with any market power mitigation measures. This would involve using the appropriate metrics and benchmarks as referred to above. It would also include monitoring and analysing the overall financial performance of market participants, using public and regulated financial accounts, and carrying out financial/technical audits and spot checks on market participants.

21. Even with the ex-post measures, given the level of structural market power modelled for I-SEM, the SEM Committee has concluded that some level of ex-ante mitigation measures will also be required to assist the competitive dynamic to a level close or equal to SRMC. Proposals and options in this regard are detailed in section 8 and summarised below.

Forward Contracting Obligation

22. Firstly, contracting forward for the sale of a certain volume of generation removes the incentive to increase prices above SRMC levels for that volume. The existing Directed Contracts approach fit this purpose in a targeted fashion in SEM, and the SEM Committee considers that a similar incentive based ex-ante mitigation measure is warranted in I-SEM, though its form and reach could be different. This is discussed in section 8.6.

Balancing Market

23. The constrained nature of the all-island power system means that any generator may possess local market power in the balancing market, i.e. submit offers which are different to SRMC, even if it does not have overall structural market power. In addition, the modelling results point to the potential for additional structural market power for energy actions in the balancing market compared with the Day-Ahead and Intra-Day markets. As a result the SEM Committee proposes implementing an explicit ex-ante bid mitigation measure for the balancing market, with 3 options, summarised as:

- Option 1: MMU Triggered Intervention, which is focused on preventing local market power being exercised by replacing bids as needs be with formulaic/prescriptive SRMC bids, manually and ex-post via the MMU/RAs;

- Option 2: Automated Intervention, which has the same intention as Option 1, but instead is applied automatically and ex-ante. There are two sub-options provided, with Option 2a involving particular software and a PST test, and Option 2b involving the “flagging and tagging” process;

- Option 3: Prescriptive Bidding Controls, which is broader and involves prescriptive bidding controls such that generator bids are set mandatorily ex-ante at formulaic SRMC levels for all trades in the balancing market. This would be with the aim not only of mitigating local market power but also short-term market power for energy-actions.

24. For each of these options, the market monitoring function of the RAs would calculate the SRMC cost curve formula for each generator and keep on file the method used by each generator to set key elements of the marginal cost. This would then be applied to replace bids as needs be for Options 1 and 2, and used for monitoring compliance with the mandatory formulae in Option 3. Further information on these options is available in sections 8.7 and 8.8.

Day Ahead and Intra-Day Markets

25. Given the structural market power indicated in the I-SEM modelling, as well as issues such as demand potentially willing to pay a higher price in the DAM and IDM rather than managing risk with more uncertain BM prices, the SEM Committee has considered various ex-ante bidding regime options for the Day Ahead and Intra-Day markets, including:

- Option 1: Prescriptive Bidding Controls, requiring all generators bids to be set mandatorily at formulaic SRMC levels, For reasons discussed in section 8, the SEM Committee does not believe it appropriate to implement this option in the day ahead and Intra-Day markets in a non-targeted fashion. Hence the SEM Committee will likely adopt one of the following three options;

- Option 2: Bidding Principles and Ex-Post Enforcement. These principles consist of ex-ante guidelines that require generator bids to generally be at SRMC, but not necessarily in every trading period, with the MMU reviewing bids for the exercise of market power using various metrics including an SRMC benchmark; or,

- Option 3: Ex-Post Enforcement Only, i.e. no explicit bidding regime (controls or principles) set ex-ante for generators, with the MMU reviewing bids for the exercise of market power using various metrics including an SRMC benchmark.

- Option 4: Market Abuse Condition, i.e specific market participants would have a licence requirement preventing market abuse. No specific bidding regime would apply in these markets. In line with other markets in EU, such as Nordpool and BETTA, the MMU will assess the market outcomes and determine whether market abuse occurred in these markets.

26. For all approaches there will be monitoring of trades by the RAs and ACER for compliance with REMIT's ex-ante market rules, to assist the RAs in the detection of market manipulation, with the RAs taking ex-post enforcement action as necessary. These options are discussed in more detail in sections 8.9 and 8.10.

Vertical Ring-fencing

27. A key consideration for an effective market power mitigation strategy is to determine whether the potential harm from vertical integration of ESB and Viridian would likely outweigh the potential benefits. If so, the continuation of ring-fencing as a market power mitigation measure would be warranted. In this context the SEM Committee is considering the rational for ring-fencing in I-SEM, taking account also of the other proposed market power mitigation measures referred to above.

28. In addition, given future market developments, the SEM Committee is considering the conditions and criteria under which ring-fencing would be applied to non-incumbents. This would need to take account of other market power mitigation measures that would be in place.

Implementation Timelines

29. Following the market power mitigation policy decision, from Quarter 2 2016 the RAs will commence associated detailed market power implementation workstreams with a view to facilitating I-SEM go-live in Quarter 4 2017. This includes any licence changes needed and other implementation issues such as the detailed operation of the FCO (if decided upon) and any organisational issues arising, for example, in relation to the market monitoring activity of the RAs.

1 INTRODUCTION

1.1 BACKGROUND

1.1.1 The decision of the SEM Committee on the High Level Design (HLD) of the Integrated Single Electricity Market (I-SEM)[5] in September 2014 highlighted the need to develop any additional measures to ensure that electricity consumers are protected from the abuse of market power. The Regulatory Authorities or RAs - the CER and Utility Regulator - have since progressed an I-SEM market power mitigation workstream, with proposals now contained in this SEM Committee Consultation Paper.

1.1.2 At a high-level, the scope of this workstream is to identify the potential level of market power in the I-SEM wholesale energy and financial markets and to decide on an associated regulatory market power mitigation strategy and measures.

1.1.3 The RAs introduced the workstream to stakeholders through the publication on 8th May 2015 of an I-SEM Market Power Mitigation Discussion Paper (SEM-15-031)[6]. The Discussion Paper outlined the expected scope and considerations for the workstream, and requested views from interested parties regarding the topics raised.

1.1.4 The RAs then published a paper on 14th August 2015 (SEM-15-046)[7] summarising the responses to the Discussion Paper and outlining the next steps. The comments received to the Discussion Paper were also published where they were indicated as non-confidential.

1.2 PURPOSE AND OBJECTIVES

1.2.1 Taking account of the comments received to the Discussion Paper, and having reviewed the related policy issues in detail, the RAs are now publishing this SEM Committee Consultation Paper on suggested market power mitigation measures in the I-SEM energy and financial markets. This paper also includes high-level information on possible implementation timelines after a decision on market power has been issued by the RAs.

1.2.2 In particular, this RA Consultation Paper proposes a regulatory strategy and measures with the aim of mitigating the incentive and ability of any market participant to exercise market power in the I-SEM physical and financial wholesale energy markets. The proposals are also designed to meet the following objectives:

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[5] Please see: http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f
[6] Please see: http://www.allislandproject.org/GetAttachment.aspx?id=2f80cf84-d7b2-47fc-884f-3c9544fc3431
[7] Please see: http://www.allislandproject.org/en/market_current_consultations.aspx?article=9c34c90d-38ea-4dee-b0de-adeed6726ea0&mode=author

- Be in line with the I-SEM HLD and its philosophy;
- Enable efficient and transparent price formation in I-SEM's physical and financial markets;
- Promote competition in I-SEM's physical and financial markets, including appropriate generation entry/exit;
- Allow for the development of liquid physical short-term[8] and forward financial trading in I-SEM, with the latter to be progressed as part of policy developed in the I-SEM "forwards and liquidity" workstream;
- Be consistent with other I-SEM policy areas, including I-SEM's Energy Trading Arrangements, Capacity Remuneration Mechanism, Financial Transmission Rights and policies to promote forward and spot market liquidity. This includes consistency with market power mitigation measures designed separately as part of these policy measures, for example in relation to the auction design for the Capacity Remuneration Mechanism and Financial Transmission Rights. For clarity, this paper does not examine market power issues that may exist within any of these policy areas; 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; and,
- Be consistent with other segments in the electricity cost chain, including in relation to electricity networks, the "DS3" programme for system services, and retail electricity markets in Ireland and Northern Ireland (NI). Again for clarity, this paper does not examine market power issues that may exist within any of these policy areas (though it does seek to be consistent with them); they are out of scope and are dealt with by the RAs separately in a manner which is assumed to deliver efficient outcomes.

1.3 STAKEHOLDER ENGAGEMENT

1.3.1 Comments to this Consultation Paper, including answers to questions posed at the end of various sections of the paper, are requested from stakeholders by 18th January 2016, to be sent in electronic format to both Gonzalo Saenz the CER at gsaenz@cer.ie and Joe Craig in the Utility Regulator at joe.craig@uregni.gov.uk .

1.3.2 The RAs will also hold a public workshop to discuss this consultation, in order to explain its proposals and to allow stakeholders air views. This workshop will be held in the Crowne Plaza Hotel in Dundalk on Wednesday 2nd December, from 14:00 to 17:00.

1.3.3 The RAs will then work to develop a Decision Paper on I-SEM market power mitigation policy, for publication in late March 2016, with a view to implementation workstreams commencing thereafter, facilitating I-SEM go-live in Quarter 4 2017.

[8] The physical short-term markets in I-SEM will include the Day Ahead market (DAM), the Intra-Day market (IDM) and the Balancing Market (BM).

1.4 STRUCTURE OF THIS PAPER

1.4.1 The Consultation Paper is structured as follows:

- Section 1 (this section) sets out the objectives for this workstream and provides details on stakeholder engagement;
- Section 2 summarises some relevant policy developments and market trends, as well as stakeholder comments to an earlier Discussion Paper, all of which frame the context in which the I-SEM market power mitigation strategy is developed;
- Section 3 sets out the relevant geographic area and trading period(s) for assessing market power in I-SEM energy and financial trading periods;
- Section 4 discusses the emerging I-SEM design and its implications for market power;
- Section 5 sets out the relevant market power metrics for the detection of market power in the energy and financial trading periods;
- Section 6 shows modelling results in relation to potential I-SEM market power, based on various scenarios;
- Section 7 assesses the performance of the current SEM market power mitigation measures, providing a backdrop to potential measures in I-SEM;
- Section 8 sets out proposals and options for market power mitigation in the I-SEM energy and financial trading periods, taking into account policy issues and proposals included in sections 1 to 7; and,
- Section 9 provides high-level information on the next steps following a decision on market power mitigation.

2 CONTEXT FOR MARKET POWER POLICY DEVELOPMENT

2.1 INTRODUCTION

2.1.1 It is worth summarising recent and likely future high-level policy developments and market trends, which may be external to the development of I-SEM itself but which impact on it and frame the context in which an I-SEM market power mitigation strategy is developed through this RA workstream. These developments and trends are summarised below and are referenced where appropriate throughout the paper.

2.1.2 We also provide a summary of comments received to the Discussion Paper published in May 2015, which we included in our summary response paper of August 2015[9]. These are provided at the end of this section and are also taken into account for developing policy in later sections of this paper.

2.2 RENEWABLE GENERATION

2.2.1 A key ongoing and future trend of consequence to I-SEM concerns the increasing role of intermittent renewable generation on the island. Already circa 20% of the island's electricity production comes from renewable generation, mostly in the form of wind power, which is a significant increase on the level when SEM went live in November 2007. It is also ahead of many EU markets. This level of renewable generation is expected to continue to increase in the coming years, given that there is a 40% renewable generation target in both Ireland and Northern Ireland for 2020. Any policy change here for Northern Ireland over the coming months would be accounted for prior to a decision on market power[10].

2.2.2 The 2020 renewables target and the increasing role of intermittent wind power will have a direct impact on the policy environment under which I-SEM market power measures are developed. For example, it reduces the amount of generation from dispatchable conventional/thermal plant at times when wind farms are generating, as can be seen in the modelling results for I-SEM shown in section 6. It has also directly led to the development of the DS3 programme to help support the target efficiently and effectively (see section 4 of this paper), for which interaction issues are considered in this workstream. These issues feed through to the market power mitigation measures discussed in section 8.

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[9] For both papers please see: http://www.allislandproject.org/en/market_current_consultations.aspx?article=9c34c90d-38ea-4dee-b0de-adeed6726ea0&mode=author

[10] As discussed in section 6, modelling for I-SEM is made on the basis of a 40% renewable target in Ireland and Northern Ireland.

2.3 INTERCONNECTION

2.3.1 There has been a significant rise in interconnection with the British electricity market since the start of SEM, with the potential maximum export capacity from the all-island market rising from 80 MW in 2007 to 950 MW. This is due to a new 500 MW "East-West" interconnector from Ireland to Britain and an increase in the export capacity of Moyle.

2.3.2 This increased interconnection – with any future interconnectors – increases the level of competition and cross-border trades in electricity, impacting on the ability of generation located in the I-SEM bidding zone to exercise market power. It is accounted for in the I-SEM modelling in section 6 and the market power mitigation measures discussed in section 8.

2.4 DEMAND SIDE MANAGEMENT

2.4.1 The RAs have recognised the potential economic and environmental benefits of greater demand side management. This could be facilitated by changes such as the roll-out of smart metering, new forms of electric demand, and aggregation of distributed generation and storage. The I-SEM detailed design in itself should also assist in greater demand-side participation by suppliers, by allowing them to submit demand bids into the Day Ahead and Intra-Day markets, indicating the maximum price they are willing to pay. This has the potential to make demand more elastic to significant changes in prices than at present.

2.4.2 The benefits of greater demand side management could include avoided investment in peaking plant, lower curtailment of wind, support for system services, and a reduced potential for the exercise of market power through demand bids limiting the ability of generators to raise prices above competitive levels (and customers' willingness to pay). This benefit could be both on a system-wide basis and a local basis, which again are taken into account in the proposals in this paper.

2.5 REMIT

2.5.1 REMIT, the Regulation on Energy Market Integrity and Transparency, entered EU law on 28th December 2011 and provides for an EU-wide market rules and monitoring framework related to wholesale energy markets in electricity and gas[11].

[11] Please see: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:EN:PDF
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:en:PDF

2.5.2 Of particular relevance to SEM and I-SEM, REMIT prohibits wholesale market abuse on an ex-ante basis, specifically "market manipulation" and "insider trading", and requires that participants publish "inside information" or inform ACER and the RAs if they seek to delay its publication. The RAs have ex-post investigatory and enforcement powers with respect to these market rules.

2.5.3 Another pillar of REMIT is the reporting by relevant market participants or third parties on their behalf of energy transaction data to ACER commencing from October 2015, which has established a market monitoring function to assess for compliance with REMIT's market rules and which the RAs can access. ACER will notify the RAs of suspected cases of market abuse for investigation and enforcement at national level by the RAs as required.

2.5.4 This enhanced market rules, monitoring and enforcement regime, which is both ex-ante and ex-post in nature, is accounted for by the RAs in developing an I-SEM market power mitigation strategy and associated measures, as proposed in section 8. Similar financial regulatory developments at EU level are also taken into account for the I-SEM financial forward market.

2.6 SUMMARY OF COMMENTS TO DISCUSSION PAPER

2.6.1 While there was some diversity in the responses received to the RAs' May 2015 Discussion Paper, the following points were the broad themes which emerged from respondents. These have been considered in developing the policy in later sections in the paper.

- There was a general view that the current market power mitigation strategy in SEM has been successful in mitigating market power in spot trading, though there are concerns, especially for suppliers, with the forward financial market and its relatively low liquidity.

- Many respondents were of the view that market power at an aggregate level will continue to be a concern in I-SEM and is an important issue for the RAs to address. This is related to limited interconnection to Europe and the concentrated nature of the market, particularly with regards to ESB's high market share. Market power in the balancing market was believed to be a particular issue, especially with the potential exercise of local market power by generators due to the significant number of local transmission system constraints on the island.

- Moreover, it was pointed out that the multiple energy trading periods in I-SEM and the temporal opportunities this may afford for the exercise of market power needs to be well understood and considered by the RAs.

- There were suggestions around examining the market power interactions between the I-SEM energy/financial markets and other areas such as

Financial Transmission Rights (FTRs), the Capacity Remuneration Mechanism (CRM) and "DS3" programme for system services.

- A significant number of respondents referred to the need for market power rules not to distort the competitive dynamic of I-SEM, and in this context some referred for the need for market rules to be targeted at dominant players/ESB rather than at all participants.

- There was a view that the market power mitigation strategy in SEM can and should be adapted by the RAs for the physical I-SEM spot markets, especially in relation to the balancing market and associated bidding rules, the continuation of a form of Market Monitoring Unit (MMU) and the application of some form of Directed Contracts (DCs).

- Other measures which respondents mentioned that could assist in the mitigation of I-SEM market power included applying "REMIT" as a tool and having contracts in place for local market power issues. For the forwards market, proposals included introducing a clearing house and/or requiring ESB to be a market maker, in order to help increase liquidity and address practical concerns such as collateral requirements.

2.7 CONSULTATION QUESTIONS

2.7.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

- *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?*

3 RELEVANT GEOGRAPHIC MARKET(S) AND TRADING PERIOD(S)

3.1 INTRODUCTION

3.1.1 The definition of relevant markets is a necessary starting point in order to analyse market structure, scales of competition and to identify potential constraints within it on competitive behaviour. It allows the relevant market participants – suppliers, consumers, etc – and the relevant constraints on competitive behaviour to be identified, feeding into any proposed market power mitigation measures as discussed in section 8.

3.1.2 In this section we first provide an introduction to general considerations which are relevant when defining electricity markets. We then provide the SEM Committee proposals in relation to the definition of relevant markets/trading periods for I-SEM itself.

3.2 RELEVANT MARKETS - CONSIDERATIONS

3.2.1 The following elements are generally taken into account when considering the relevant market:

- The product(s) or services offered in the market;
- The timeframe in which the relevant products are traded;
- The stage of the supply chain where the activity takes place (in this case production, transmission, distribution);
- The geographic area in which the supply and demand for the product interact.[12]

3.2.2 The European Commission has produced guidance on how the concepts of relevant product and geographical markets should be applied in its competition investigations as shown in the box below.

Box 3.1: Definition of relevant markets

> *The European Commission has defined the main dimensions for determining the relevant market in competition cases as follows:*
>
> *'A relevant product market comprises all those products and/or services which are regarded as interchangeable or substitutable by the consumer, by reason of the products' characteristics, their prices and their intended use'.*
>
> *'The relevant geographic market comprises the area in which the undertakings*

[12] In electricity markets, relevant markets do not always correspond to geographical areas, but rather to an electrically defined set of generators that can compete to meet demand in a given area. The European Commission's definition of relevant markets, stated next, is broad enough accommodate such peculiarities of electricity markets.

> *concerned are involved in the supply and demand of products or services, in which the conditions of competition are sufficiently homogeneous and which can be distinguished from neighbouring areas because the conditions of competition are appreciably different in those area'.*[13]

3.2.3 The nature of electricity networks, in particular the need to balance supply and demand at each point in time and the relatively inelastic demand (driven by a lack of effective substitutes, at least in the short and medium term), makes them susceptible to the exercise of market power. In the electricity sector, relevant markets are commonly defined across three main dimensions, focusing on identifying the relevant product and evaluating potential substitutes for it:

- **Product** – given its generally non-storable and instant nature (i.e. cannot be stored cost-effectively at a sufficiently large scale), electricity represents a different product depending on the delivery time. This implies that electricity produced during the morning hours is not substitutable with production in the afternoon peak hours (electricity generally cannot be bought cheap and sold for more in a later period). Similarly electricity production in the winter is not substitutable with production in the summer.
- **Geography** – geographic markets will differ mostly in terms of the transmission constraints, which limit the generators' ability to compete to serve load in constrained areas.
- **Time** – electricity products can be traded in different time frames from forward markets to day ahead markets to short term balancing markets. These different time contracts are linked and to some extent substitutable however they also serve different purposes and may be considered different markets for the purpose of competition analysis.[14]

3.2.4 The area where different suppliers and consumers interact represents the geographic dimension of the market. Defining relevant geographic markets is particularly challenging in electricity networks, because transmission constraints are likely to cause varying degree of market segmentation between and within bidding zones. Therefore the relevant geographic market may not coincide with administrative/jurisdictional or bidding zone boundaries. Instead the relevant market is defined by the interaction between transmission constraints, the location of demand and the location and nature of generation supply offers. The extent to which a transmission constraint binds depends on the offers and bids from generators and

[13] European Commission, "Commission Notice on the definition of the relevant market for the purpose of competition law"

[14] That said, there are clear interactions between the different trading timeframes. For example, forward contract prices will be a function of (expected) spot prices.

demand, and where they are located compared to the capacity of the transmission network. When binding, those transmission constraints may restrict the ability of generators from outside the congested area to serve demand, and therefore would no longer be considered to form part of the same market.

3.2.5 It is important to distinguish between bidding zone-wide market power and local market power. Bidding zone-wide market power may occur when a generator (or generation company) has significant structural market share in the broader market (for example, the all-island market) or is pivotal in meeting overall market demand, especially when supplies are limited. Local market power arises when transmission constraints separate the broader market into distinct geographic markets, where some generators are needed, or in the most extreme case, are the only local generator, in order to meet demand. Local market power is most likely to arise in areas where demand is much higher than local generating capacity ("load pockets") and areas that are weakly-interconnected with the rest of the transmission system15. This is especially relevant to the balancing market as discussed later in this paper, as this is the timeframe in which the Transmission System Operator (TSO) will resolve local constraints.[16]

3.2.6 Market rules will determine whether transmission network capacity has an impact on market definition. In electricity, an "unconstrained" market is one where network constraints are assumed not to limit the ability to match system generation and demand. In a "constrained" market, the capacity of the network is taken into account when matching bids and offers.

3.2.7 Most of the market monitoring and competition analysis to date has taken national borders as the boundaries of the market. However, as referred to above, the nature of electricity transmission networks means that the relevant markets can be smaller than national boundaries where there are internal transmission constraints, and larger than national boundaries where there are no internal transmission constraints and interconnector capacity is available for cross-border competition. How this relates to I-SEM is discussed later in this section.

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[15] EirGrid's operational constraints are detailed in:
http://www.eirgrid.com/operations/dispatchbalancingcosts/operationalconstraints
This indicates that they do not change frequently. That would suggest they are fairly static. In reality, they are probably a bit more dynamic than that.

[16] The Day Ahead and Intraday markets are unconstrained in the bidding zone, as discussed later in this section.

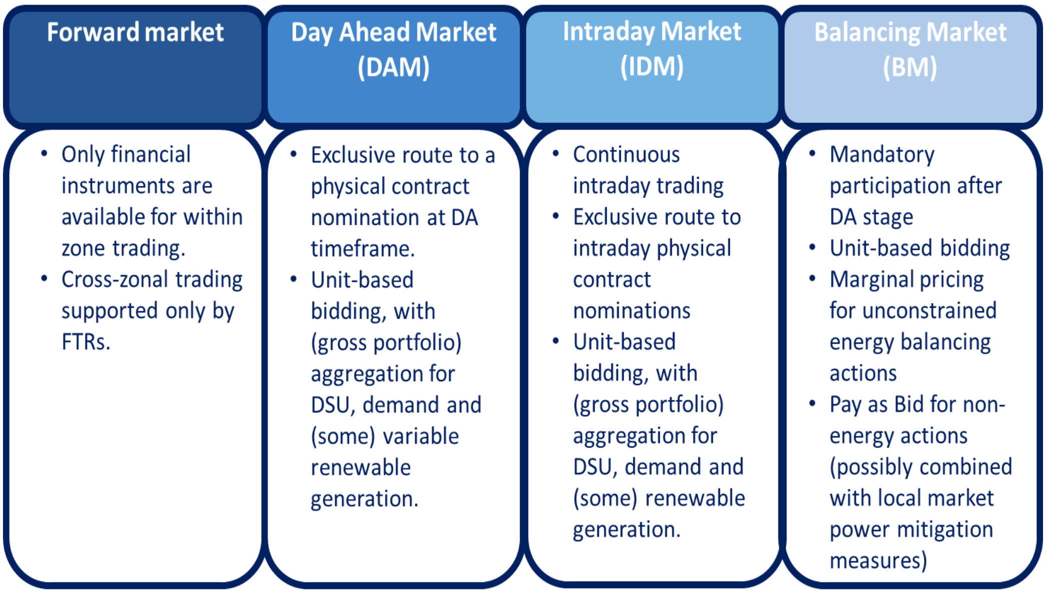
3.3 I-SEM TRADING PERIODS

3.3.1 The definition of relevant markets for I-SEM also depends on the timing of trading arrangements. The I-SEM detailed design includes four trading time frames:

- Forward Market;
- Day ahead Market (DAM);
- Intra-Day Market (IDM); and,
- Balancing Market (BM).

3.3.2 These energy markets of various timeframes are as illustrated in Figure 3.1 below.

Figure 3.1: I-SEM energy markets



3.3.3 The forward market is a financial-only market without physical delivery of the contracted power. The DAM will be the only route in the Day-Ahead timeframe for generators to obtain a physical schedule. Similarly, the IDM will be the only route for generators to physical scheduling in the Intra-Day timeframe. The BM will run concurrently with the IDM, although the TSOs are expected to refrain from taking energy balancing actions (i.e., engage in balancing trades to balance total supply and demand) before gate closure.

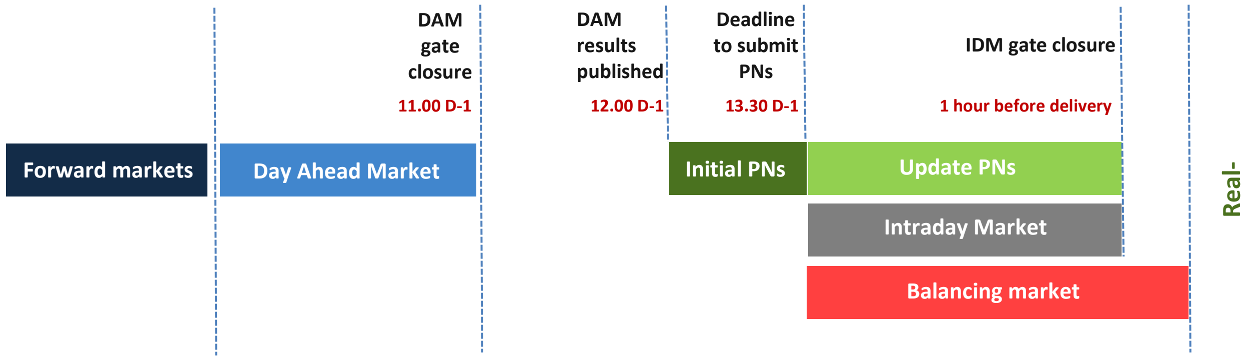
3.3.4 The DAM and the IDM operate on the basis of an unconstrained model, i.e. market outcomes are determined not taking account of network constraints. In the BM, however, physical transmission and operational constraints need to be taken into account by the TSO when determining the dispatch of units to meet demand.

3.3.5 Figure 3.2 below illustrates the I-SEM trading timeline. The trading day in I-SEM will cover 24 hours beginning at 23.00 each day. This is to align the I-

SEM with the trading day in other European electricity markets, where it begins at midnight CET.

3.3.6 In the I-SEM the IDM and the BM will be open and operate in parallel after the DAM has closed and the TSOs have received the detailed Day-Ahead Physical Notifications from the market participants. The gate closure for the IDM market is one hour before delivery, as illustrated below.

Figure 3.2: I-SEM energy markets trading timeline



3.3.7 Balancing actions can thus be undertaken by the TSOs in I-SEM in advance of the BM as defined in the Electricity Balancing Network Code (EBNC), i.e. the BM is the market for balancing capacity and energy used after gate closure time, which is one hour ahead of delivery. Although the TSOs will have the ability to take early energy and non-energy actions (while the IDM is still open) it is intended that TSOs will seek to keep early energy actions to a minimum and conduct early intervention for non-energy actions only.

3.4 RELEVANT MARKETS IN I-SEM

3.4.1 The relevant electricity markets are defined along the dimensions of **product**, **geography** and **time** as discussed earlier. Next we discuss these three dimensions in the I-SEM context.

Product

3.4.2 The most granular definition would define the product by the number of delivery periods in each trading timeframe. In the forward market, electricity is traded as baseload, mid-merit, and peak load product. In the I-SEM, electricity in the DAM will be traded for 1-hour delivery periods, thus up to 24 products are traded each day. In the BM, the delivery period is 30 minutes, thus there are up to 48 products each day. The definition of products could be aggregated to include several delivery periods (e.g., peak- and off-peak hours) but the SEMC does not think that such an aggregation would be appropriate given the varying hourly dynamics of electricity markets. Therefore we propose to apply the granular definition of hourly product in the DAM and IDM, and half-hourly product in the BM.

Time

3.4.3 The timing of trading will determine the size of supply side of market (i.e., potential set of suppliers), For example, the market for energy traded for delivery beginning at 13:00 in the DAM, will not be the same market as the one for energy for the same delivery period but traded in the IDM at 10:00. The set of generators in the Day-Ahead timeframe is likely to be much larger than Intra-Day, since many generators can still start up for next day delivery, while they may not be able to do that within the trading day.

3.4.4 The timing of the trade/balancing action has a significant impact of the size of the relevant market and the ability to exercise market power. The characteristics of the network mean that the supply/demand situation and other market conditions will change on a continuous basis and transmission constraints may evolve such that localised market power can arise, and move over time.

3.4.5 The ability of some generators to provide electricity in a given half-hourly period will also be influenced by technical characteristics such as start-up and ramp up rates which restrict the level of generating capacity available in any given time period. In this case, the generation capacity available in the market will be constrained by the ability of generators to start up or ramp up production within that time frame. This means that generally the shorter the time period to real-time settlement the lower the available capacity will be and the greater the ability of generators to exercise market power.

Geography

3.4.6 The largest possible geographic market in I-SEM includes all generators and load on the island, and the capacity of the interconnectors with GB, since that is the limit on cross-border (or between bidding zone) competition. This is the relevant geographic market when there are no internal transmission constraints and the interconnectors' entire capacity is available. This is same geographical definition as the current SEM. Price coupling will not enlarge the geographic market, since with the physical capacity of interconnectors unchanged, any potential exercise of market power in the I-SEM market is constrained by competition from cross-border generators only to the extent that output of those generators can be physically delivered to the I-SEM market.

3.4.7 The relevant geographic market is primarily determined by (binding) transmission constraints, which may not coincide with administrative or bidding zone boundaries. Transmission constraints may give rise to locational market power when in order to relieve congestion, a limited number of generators may be available to be re-dispatched. The relevant supply in a congested area will consist of the offers of those generators that can relieve the congestion, up to the MW amount they can supply within the required amount of time. Thus, depending on the constraint and the timeframe, the relevant geographic market may be quite small, as may the number of relevant generation plants.

3.4.8 Thus for I-SEM, since the redispatching is to be performed in a market-based manner in the BM using INC and DEC bids17, the relevant market will be determined by the constraint that requires the redispatch, and competition may be much weaker than in the day-ahead market coupling. To illustrate their importance, we have summarised experience with internal transmission constraints in the SEM in Appendix A.

3.5 DEFINITION OF RELEVANT MARKETS IN I-SEM

3.5.1 Taking account of the above issues, the SEM Committee proposes the following definition of relevant markets and trading periods for I-SEM.

Forward market

3.5.2 In the forward market, the product traded is a financial/hedging instrument that involves no physical delivery, but rather serves as a form of insurance against spot price increases and volatility. Therefore, we propose that all forward products traded prior to the opening of the DAM should be treated as part of a single relevant forward market that includes I-SEM capacity and the capacity of the interconnectors.18

DAM

3.5.3 Electricity is traded as an hourly product for the next day, without considering transmission and generator operational constraints. Therefore, the geographic market should include all generators on the island and interconnection capacity. It is important to note that the size of the geographic market will not exceed the combined capacity of the local I-SEM capacity and the capacity of the interconnectors. Although market coupling will make the interconnector flows more efficient, it will not enlarge the relevant geographic market beyond the physical capacity of the interconnectors.

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[17] Incremental (INC) offers and decremental (DEC) bids in the BM will represent the prices at which a market participant is willing to deviate from its market schedules established in the DAM and the IDM at the instruction of the TSO. If the TSO accepts an INC offer, then the associated generator will be instructed to generate more in return for a payment specified in the INC offer. When a generator is instructed to generate less than, it will purchase back the difference between its market schedule and actual generation at the DEC price.

[18] This definition of a forward market should be revised if smaller hubs for forward trading develop were to develop in the future.

IDM

3.5.4 As in the DAM, electricity will be traded as an hourly product, without considering transmission and generator operational constraints. Therefore the relevant geographic market will include all generators on the island and the interconnector capacity. Although the relevant IDM will have the same geographic scope as the DAM, there are some structural differences between the DAM and the IDM that will (often) make them subject to different market conditions. In particular, unexpected changes in market conditions e.g. changes in demand levels, input costs, and wind generation, will always occur and cannot be predicted and thus arbitraged away. Unexpected events could increase or decrease the ability of any market participant to exercise market power depending on whether these events led to a decrease in available generation capacity (and/or an increase in demand) or vice versa.

BM

3.5.5 In the BM, electricity will be traded as a half-hourly product, taking into account transmission as well as operational constraints. Transmission constraints are the most important structural difference between the BM and the other physical markets. In addition, the generators' operational constraints (e.g. ramping rates) will limit the available supply, especially closer to real time. The size of the relevant geographic market in the balancing timeframe will depend on whether within I-SEM bidding zone transmission constraints are binding, and will thus be dynamically changing. The largest possible size of the geographic market will coincide with that of the IDM and the DAM: combined I-SEM capacity and the capacity of the interconnectors. The smallest relevant BM may be as small as a constrained area with a single generator.

3.6 CONSULTATION QUESTIONS

3.6.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

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

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

4 I-SEM DESIGN, INTERACTIONS AND IMPLICATIONS

4.1 INTRODUCTION

4.1.1 In this section we first discuss a potential definition of competitive behaviour in I-SEM and possible strategies for exercising market power. Next, we examine aspects of the I-SEM forward market design and the physical market design for market power implications. This section concludes with a discussion of market power that may arise from the interactions with the CRM, Financial Transmission Rights and the DS3 programme.

4.2 STRATEGIES FOR EXERCISING MARKET POWER

4.2.1 Market power analysis requires a definition of competitive behaviour, which we define as:

Competitive offers equal short run marginal cost (SRMC), where SRMC includes relevant opportunity costs[19].

4.2.2 In other words, generator offers at SRMC define competitive behaviour and such behaviour is a key metric for defining competitive prices (i.e. market outcomes) in the I-SEM physical markets. Therefore prices above or below this competitive benchmark would indicate a possible exertion of market power.

4.2.3 It is important to note that SRMC-based pricing in the physical markets is compatible with the commercial objective of efficient generators to recover both fixed and variable costs through market revenues, through inframarginal rents accrued and/or through capacity payments, as discussed also in section 8. This is irrespective of whether or not an administered scarcity price is adopted as part of the market design. In a competitive wholesale market design, fixed costs that are not SRMC are recoverable through a combination of inframarginal rents, scarcity pricing if permitted and capacity markets among others.

4.2.4 Against this competitive benchmark, there are several ways in which market power can be exercised in I-SEM[20]. This includes:

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[19] In addition, inframarginal rents earned during scarcity pricing periods would also be consistent with competitive behaviour. An administered scarcity pricing mechanism, if introduced, would ensure that market participants have no incentive to inflate their scarcity rents.

[20] Twomey, Green, Neuhoff and Newbery (2009), "A Review of the Monitoring of Market Power: The Possible Roles of Transmission System Operators in Monitoring for Market Power Issues in Congested Transmission Systems", published by the Center For Energy and Environmental Policy Research,

- **Physical or quantity withholding**—generator deliberately reduces its MW offer, even though it can offer at its marginal cost, in an attempt to drive up the market price. Physical withholding can be done in a number of ways, such as simply not offering a unit or declaring an outage.
- **Financial or economic withholding**—generator offers at prices higher than the competitive (marginal cost-based) offer for the particular generator.
- **Predatory pricing strategy (or price suppression)** – generators offers at prices below the competitive level to increase their market share in detriment of competitors.
- **Transmission related strategies**—bidding in a way that creates or aggravates transmission congestion, with the purpose to raise the price a generator receives at a particular location. In I-SEM these strategies are most likely be implemented through offers in the DAM and the IDM, and INC offers and DEC bids submitted in the BM.

4.2.5 These strategies can also be implemented in combination. For example, a generator that can submit supply curve offers could be engaged in a simultaneous physical and financial withholding.

4.2.6 It is important to differentiate between high prices that are due to the exercise of market power and high prices arising due to scarcity which are necessary to signal the need to make additional generation available (including new investment) or to curtail demand. In general, the RAs consider that generators should not be allowed to include their own expectation of scarcity rents or future inframarginal rents in their offers because there is a concern of not being able to differentiate between the exercise of market power and genuine legitimate behaviour leading to high prices due to scarcity. These issues are best addressed by appropriate market design; for example, this could include administered scarcity pricing if introduced in the I-SEM, or market instruments that facilitate convergence between physical markets including virtual bidding where market participants may reflect expectations of forthcoming scarcity through submitting demand side bids into the near term markets.

4.3 FORWARD MARKET AND IMPLICATIONS

4.3.1 In I-SEM, trading in the forward market will be purely financial in the sense that contracts will not have any obligation for physical delivery or off-take. These transactions will generally be settled financially against the market price determined in one of the physical markets (i.e., DAM, IDM, or BM). The

Massachusetts Institute of Technology, Cambridge, MA, USA; reprinted from Journal of Energy, Literature, Vol. 11, No. 2, pp. 3-54, 2005.
http://web.mit.edu/ceepr/www/publications/reprints/Reprint_209_WC.pdf

primary purpose of forward markets is to provide hedging opportunities against volatile spot prices.

4.3.2 Market participants that engage in cross-border trade will face the additional risk of potential divergence and volatility between the I-SEM and the neighbouring (primarily GB) market prices. To hedge against these price differentials, it is foreseen that Financial Transmission Rights (FTRs) will also be offered in the forward timeframe. FTRs give their holders the right to the congestion rent (i.e., price differential between the I-SEM and neighbouring market price), and thus provide a financial hedge for cross-border trade. Since the value of the FTRs will be determined by the market price in the DAM, holding an FTR may increase the incentive to exercise market power in either bidding zone (increase the price in the importing zone or decrease the price in the exporting zone), but does not have any effect on the ability to exercise market power in the physical markets.[21]

4.3.3 Trading in the forward financial market should primarily be driven by expectations regarding market conditions in later (DAM, IDM, BM) timeframes, which creates important temporal interactions with market power implications. It is often assumed that competitive physical markets limit the exercise of market power in the forward market, since if a potential buyer of a forward contract is confident it can obtain electricity in the physical spot market at a competitive price, it will be unwilling to accept a forward price that is out of line of the expected spot price.

4.3.4 Furthermore, as noted in I-SEM Market Power Mitigation Discussion Paper, demand for forward contracts is likely to be more elastic than in the physical markets since potential buyers of forward contracts "can choose not to contract at a price that is above their expectations of the spot price (i.e. remain unhedged) or use alternative forms of hedging, such as the purchase fuel of hedges". Arguably barriers to entry, i.e. the provision of forward products, should also be lower than in the physical markets given that large-scale assets (generation plants) do not need to be built in response to price signals. These factors would tend to limit the potential for forward market power, as assetless traders could also offer CfDs.

[21] Although FTRs will be sold in the forward timeframe to support forward (cross-border) trades, their value will be determined in the spot/physical market(s). This creates a linkage between the forward and spot/physical markets. If someone can manipulate the spot market price to increase the value of FTRs, they may have an incentive to buy FTRs even if they do not engage in any forward trading. This may, all else equal, raise the price of FTRs in the FTR auctions, and some market participants who would want to buy/sell forward cross-border energy may decide not to do so because hedging (FTR) is more expensive. Thus, there will be distortions in the spot market, FTR auction, with knock-on effect on the forward market.

4.3.5 That said, economic literature suggests[22] that *competitive physical spot markets mitigate only the component of forward prices that is based on spot market expectations*. Risk averse buyers, typically electricity suppliers, value forward contracts also because they provide a hedge against spot market volatility; in other words, they are willing to pay for price certainty. Thus, if some providers of forward contracts have market power in the forward market, for example, because there are certain barriers to entry, they may extract above-normal profits in the forward market from risk-averse buyers. Robinson and Baniak (2002)[23] theoretically demonstrated that *generators with forward market power have an incentive to create volatility in the spot market.* They also found some empirical support for their hypothesis, by examining two GB generator's market behaviour in the 1990s.

4.3.6 If there is a level of market power in the forward market, generation owner(s) with market power can have the ability to influence the forward price at which it will sells power forward. This would disadvantage contract buyers (typically electricity suppliers), negatively impacting on the wholesale and retail markets, which could harm consumers. Whether potential barriers to entry could lead to market power in the forward market as exemplified above is unclear at this point, though the RAs have not seen significant ongoing evidence that forward market power has been exercised in SEM as discussed in section 7.

4.3.7 Furthermore, ongoing EU regulatory developments such as EMIR[24] and MiFiD[25] assist in detecting and preventing market power abuse in the forward financial market, with a role for the relevant financial regulatory authorities in relation to this matter. The RAs will co-operate with the financial regulatory authorities to the extent appropriate, but it is not anticipated that the RAs will be the lead authorities in this area.

4.3.8 Overall, taking on board the factors discussed above, the potential for market power abuse in I-SEM appears to be weaker in the forward market compared to the physical markets. In any event EU financial regulation would appear to be the main instrument to prevent the exercise of forward market power. Hence, for the remainder of this paper the focus is generally on I-SEM physical rather than financial markets, as reflected in section 8 on I-SEM market power mitigation measures.

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[22] McDiarmid, R., C.S. Bogorad and M.S. Hegedus (2002), 'Comments of the American Public Power Association and Transmission Access Policy Study Group on Market Power, Market Monitoring, and Market Mitigation Issues in Supply Margin Assessment and Standard Market Design,' FERC Conference on Supply Margin Assessment, Docket No. PL02-08-000.

[23] Robinson, T. and A. Baniak (2002), 'The Volatility of Prices in English and Welsh Electricity Pool,' Applied Economics, 34:1487–95.

[24] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32012R0648&from=EN

[25] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:02004L0039-20110104&from=EN

4.4 PHYSICAL MARKETS AND IMPLICATIONS

4.4.1 The DAM will be based on the European Price Coupling initiative using the EUPHEMIA algorithm. One of the main goals of the new market design of the I-SEM is achieving efficient interconnector flows with GB at the day ahead and Intra-Day timeframes. The main implication for market power in I-SEM is that a more efficient allocation of interconnector capacity may exert additional competitive pressure and thus act as a mitigating factor of market power in I-SEM, especially in the DA and ID markets. See Appendix B for an assessment of the extent of current interconnector flow inefficiencies.

4.4.2 Some of the I-SEM Energy Trading Arrangements (ETA) detailed design may, to an extent, mitigate market power, while others may either potentially create opportunities for market manipulation or make the detection and mitigation of market power more difficult than in the existing SEM. Table 4.1 below lists those I-SEM design elements that we have identified to have the most significant implications for market power mitigation. These fall into two general categories: transparency (the ability for a market monitor to identify whether or not a generator has withheld a plant, either financial or physical) and market rules which limit the ability or incentive to physically withhold capacity (the BM will be mandatory via licence condition).

Table 4.1: I-SEM design elements and their implications for market power mitigation

Design element	Market power implications
Unit-based bidding in DAM, IDM, BM	• Weakens the incentive to deviate from marginal cost (MC) bidding, because offers linked to individual generators/units are easier to compare to unit's MC than offers based on a portfolio of generators • Makes market power monitoring/mitigation easier
Offer/bid format in DAM and IDM	• Unlike in SEM, offers in I-SEM will no longer have a separate component for (1) energy; (2) no-load, and (3) start-up costs required at all times • Makes potential verification against SRMC more difficult, since in order to recover their fixed (start-up and no-load) costs, generators may have to increase their offers above MC • Hourly offers, vs. single daily offers in SEM, may potentially create more opportunities for market manipulation[26]
INC/DEC bids and offers in the BM	• Incremental (INC) offer: offer to increase generation or decrease demand relative to cumulative day-ahead and

[26] In some markets, e.g. PJM, hourly offers have not been allowed in order to limit opportunities gaming, although that is currently being reconsidered.

Design element	Market power implications
with mandatory participation	IDM trades • Decremental (DEC) bid: bid to decrease generation or increase demand relative to cumulative day-ahead and IDM trades • INC offers and DEC bids can be used as means of exercising local market power[27]
Physical notifications (PNs)	• First submitted to the TSOs by market participants after DAM close; will be the starting position used for imbalance settlement. • PNs must be linked to ex-ante positions at gate closure. Before gate-closure, PNs can represent the best estimate of demand or generation[28] • Exact requirement may have an impact on incentives and monitoring[29]
Voluntary participation in IDM and DAM	• Identifying physical withholding may be difficult • Participation will be incentivised, given the fact that physical schedules are established in these markets • Participation may be mandatory for CRM RO holders
Individual market participant balance responsibility	• Submitted to the TSOs by market participants after DAM close; will be the starting position used for imbalance settlement. Final imbalance settlement will be based on trading positions in DAM, IDM, and BM. • Promotes convergence between intertemporal markets • May lead to greater liquidity in DAM

[27] INCs/DECs are offer/bid prices in the BM for both energy and non-energy (e.g., constraint management) actions. Energy actions (i.e. balancing energy) should only be traded after the IDM is closed. This should limit the ability of any participant to choose BM over IDM, and vice versa. The BM before gate closure would not be alike to an all-island pool, because the TSO would typically be solving local problems with its non-energy actions.

[28] Although PNs must be linked to ex-ante gate closure, there may still be a tolerance around this.

[29] Actual DAM trades determine the DAM prices. PN is what the market participant tells the TSO it will consumer/generate in real time. Ideally, the PN (in the DA timeframe) should be an accurate reflection of the DAM trades. The TSO will likely use the PNs to determine whether it needs to trade in the BM; therefore PNs create linkages between DAM and BM. If PNs and DAM trades are only loosely related, someone could manipulate the DAM, or the BM through its PNs, without much imbalance penalty.

4.4.3 For the reasons summarised in the table above, unit-based bidding is likely to make market power monitoring easier than in those markets with portfolio-based bidding, while using a different bid format in the DAM and IDM from the current bid format in the BM, could make the detection of market power more difficult. In general, detecting deviations from marginal cost bidding is relatively straightforward, as exemplified 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.

Box 4.1: Representing fixed costs in generator offers in I-SEM

Suppose a generator with a capacity of 50 MW, incurs a marginal cost (fuel + variable operations and maintenance + emission cost) of €50/MWh when generating, and €500/start cost for each start (equivalent to €2,500/hour). Furthermore, once started, the generator must continue to run for a minimum of 2 hours ("minimum uptime" constraint). Therefore, if the generator sells energy in only one hour, it will incur a no-load cost of an additional €50/MWh (the unit cost of running one extra hour).

- If the generator cannot explicitly specify the start-up and no-load costs in its offer, and it can only submit a single/simple €/MWh offer, it would have to submit an offer of:

  €50/MWh+€500/50MW+€50/MWh = €110/MWh,

  in order to recover its costs. Since, the offer exceeds the generator's marginal cost, it may appear that it is exercising market power (financial withholding), when it fact it would just recover its costs.

As part of the ETA design the SEM Committee has decided that in the balancing market timeframe, market participants should represent any fixed costs (such as those reflected in start-up and no load costs in SEM) within their simple incremental offers and decremental bids.

4.4.4 Participation in the BM will be mandatory. After the close of the DAM auction, market participants will be required to submit physical notifications (PNs)30 to the TSO, along with incremental (INC) offers and decremental (DEC) bids.31 If dispatching a generator according to its PN would endanger system security, or the generator is simply no longer needed in real time, the TSO would instruct it to deviate from the PN by accepting its INC offer or DEC bid, depending on whether an increase or a reduction in the generator's output is desired.

[30] PNs should represent the amount a generator intends to generate based on its DAM, IDM and BM trades.
[31] INC offers and DEC bids also apply to dispatchable demand in the BM.

4.4.5 The ETA detailed design decision specified that:

- A unit that is **'constrained down'** due to a dispatch instruction from the TSOs *pays back the lower of its decremental (DEC) bid price or the imbalance price*; and,

- A unit that is **'constrained up'** due to a dispatch instruction from the TSOs *receives the higher of its incremental offer price or the imbalance price*.

4.4.6 A potential market power-related issue in I-SEM is that the DAM and IDM auctions clear without a consideration for transmission constraints. In other words, these markets yield so-called "unconstrained schedules". If some of these schedules are not feasible in real time in the BM (e.g., they would violate some transmission constraints, or aggregate supply would exceed demand), then the TSO will have to accept some INC offers or DEC bids to balance the system.

4.4.7 The key implication of local market power is the incentive it creates for the generator that possesses it. If a generator knows that it will have to be dispatched by the TSO in real time (e.g., in order to meet demand in a load pocket), it will have less of an incentive to bid competitively, since it is all but guaranteed to run in the BM, such that its INC and DEC bids are not at competitive levels. Appendix C provides examples of the potential exercise of this kind of market power in I-SEM.

4.5 INTERACTIONS WITH THE CRM AND IMPLICATIONS

4.5.1 Under the proposed design of the I-SEM an explicit Capacity Remuneration Mechanism (CRM) will be introduced. The CRM is intended to work alongside any targeted contracting mechanisms that serve as backstop measures to address specific security of supply concerns.

4.5.2 The CRM capacity product, Reliability Option (RO) will have to be backed-up by physical capacity. Reliability Options are seen as a tool to mitigate against any exercise of market power by removing the incentive for capacity contract holders to bid into the reference market (one of the physical markets) above the strike price specified in the RO contract. A generator that holds an RO also has a strong incentive to make sure they are operating/available when the RO is called or they are at risk for the difference payment. However the SEM Committee remains concerned about the ability and incentive of market participants to exercise market power up to the level of the strike price.

4.5.3 The key source of interaction between the CRM and the physical markets is the Market Reference Price (MRP). The value of ROs will be influenced by the level of the Strike Price and the MRP, which is in turn determined in the physical markets. Therefore, if a RO holder possesses market power in the physical markets, it may have an incentive to inflate or suppress the MRP, depending on the relative size of its RO holdings and physical market positions. The SEM Committee is currently evaluating the most appropriate MRP for the CRM.

4.6 INTERACTIONS WITH FTRS AND IMPLICATIONS

4.6.1 Financial Transmission Rights (FTRs) are a form of transmission rights that do not guarantee physical capacity on the interconnector, but give its holder the right to the price differential between the I-SEM and the neighbouring market in the DAM. FTRs will initially will be introduced only in the DAM, therefore potential interaction will be limited to that market. The key source of the interactions is that:

- Value of FTRs is determined by the source and sink energy market prices, i.e. the expected I-SEM DAM price and the expected GB DAM price, or vice versa.

4.6.2 If some FTR-holders had the ability to manipulate in the DAM market price, either in I-SEM or GB or both, they could do so in order to increase the value of their FTRs, though it is noted that holding an FTR increases the incentive to manipulate the DAM price but not the ability. For example, they could seek to inflate the I-SEM DAM in order to increase the value of their FTRs. Similarly a potential FTR holder could engage in price suppression in the I-SEM DAM in order to reduce the cost of purchasing an FTR.

4.7 INTERACTIONS WITH THE DS3 AND IMPLICATIONS

4.7.1 The DS3 Programme has been created to meet the challenges of operating the all-island electricity system securely with increasing amounts of variable non-synchronous renewable generation over the coming years.32 The System Services, which have been approved in principle, are outlined in the following table.[33]

Table 4-1: Products, categorisation, and technology

Product	Type of service
New Services	
Synchronous Inertial Response (SIR)	Grid stability
Fast Frequency Response (FFR)	Grid stability
Dynamic Reactive Response (DRR)	Grid stability
Ramping Margin 1 Hour (RM1)	Ramping margin
Ramping Margin 3 Hour (RM3)	Ramping margin

[32] See EirGrid – "The DS3 Programme: Delivering a Secure, Sustainable Electricity System".
[33] Single Electricity Market, DS3 System Services, Technical Definitions, Decision Paper, SEM-13-098 And IPA, "Economic Appraisal of DS3 System Services", Page 44.

Product	Type of service
Ramping Margin 8 Hour (RM8)	Ramping margin
Fast Post-Fault Active Power Recovery (FPFAPR)	Grid stability
Existing services	
Steady-state reactive power (SRP)	Grid stability
Primary Operating Reserve (POR)	Fast reserve
Secondary Operating Reserve (SOR)	Fast reserve
Tertiary Operating Reserve 1 (TOR1)	Fast reserve
Tertiary Operating Reserve 2 (TOR2)	Fast reserve
Replacement Reserve (De-Synchronised) (RRD)	Slow reserve
Replacement Reserve (Synchronised) (RRS).	Slow reserve

4.7.2 Unlike in SEM, the System Service products under DS3 should be procured through competitive mechanisms, unless potential competition is insufficient. An assessment by IPA34 - commissioned by the RAs - suggests that these markets can be highly concentrated: when analysed by splitting these products into groups according to their main characteristics (grid stability services; ramping margin services; fast reserve services; slow reserve services), each has a HHI above 2,000 ("high" market concentration). Therefore, there is a potential for both market-wide and local market power in the ancillary services market.

4.7.3 The RAs expect that there will be interactions between the various requirements within DS3 System Services and the physical markets. Whenever these constraints bind, they create local markets both for energy and DS3 products, and thus give rise to local market power.

4.8 CONSULTATION QUESTIONS

4.8.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

- *Do you agree with the proposed definition of competitive behaviour and pricing in I-SEM?*
- *Do you think that the suggested examples in which market power can be exercised in I-SEM captures the relevant issues?*
- *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?*

[34] IPA, "Economic Appraisal of DS3 System Services".

- *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?*

5 RELEVANT I-SEM METRICS

5.1 INTRODUCTION

5.1.1 This section of the paper examines appropriate metrics to measure for market power in the relevant I-SEM markets/trading periods.

5.1.2 The structure-conduct-performance (SCP) paradigm provides a basic but powerful framework for market power analysis. Its three main components are:

- **Structure** - refers to the established market structure, such as market shares, market concentration or the pivotality of suppliers. Such structural market power considerations may influence market participants' ability and incentive to exercise market power;
- **Conduct** or behaviour - whether market participants actually engage in economic withholding or physical withholding or other forms of non-competitive behaviour; and,
- **Performance** - whether market performance (e.g., market prices, price mark-ups, net revenues, liquidity) is affected by market participants' non-competitive conduct.

5.1.3 The original SCP model posited that market structure had an influence on market participant conduct, which in turn could determine overall market performance. More recent applications of the SCP paradigm have considered a more dynamic relationship between the three components. For example, market participants may behave competitively in concentrated markets, but also non-competitive behaviour may occur in markets that are unconcentrated. Therefore, an effective strategy to detect market power may require an analysis of all three components.

5.2 METRICS TO DETECT MARKET POWER

5.2.1 In general, the techniques for detecting market power can be classified along two dimensions as shown with illustrative examples in Table 5.1 below: whether they are applied ex-ante or ex-post; and whether they are used to measure market power in the long term or the short term. Ex-ante indicators can generally be used to detect potential market power because they measure such ability before any market power abuse occurs, while ex-post indicators can be used to detect an actual exercise of market power. Long-term measures are either applied over a longer period or are focused on relatively stable aspects such as market structure. Short-term indicators are used to detect actual or potential exercise of market power in a short period (e.g. in a single auction), and may be combined with measures to automatically mitigate market power (e.g. setting bids exceeding a competitive level equal to that price).

Table 5.1: Classification of market power detection metrics in electricity markets

	Ex-ante	Ex-post
Long-term metrics	• **Structural indices**: e.g. Market share, Herfindahl-Hirschman-Index (HHI), RSI • **Simulation models** of strategic behaviour	• **Competitive benchmark analysis** based on historical costs, mark-ups • **Comparison of market bids** with profit maximising bids and competitive bids
Short-term metrics	• **Bid screens** comparing bids to references bids • **Some structural indices**, such as Pivotal Supplier Indicator (PSI) and congestion indicators	• **Forced outage analysis and audits** • **Residual demand analysis**

Source: CEPA and Twomey, Green, Neuhoff & Newbery (2009)[35]

5.2.2 Often it is necessary to assess these three types of indicators - SCP - jointly. A market may not be structurally competitive, but market participants may behave in a competitive manner, and thus the overall market performance may be competitive. The reverse may also be true: a market may appear to be structurally competitive in its construct (through legislation, OTC and exchange contracts, etc.), but the actual behaviour may not be competitive. It is important to keep all of these measures in mind in order to detect market power and to facilitate competition.

5.3 MARKET POWER METRICS IN SEM

5.3.1 The RAs have considered/used the following metrics to assess market power in physical wholesale market power in the SEM:

- Market shares;
- Residual Supply Index (RSI)[36];
- HHI - sum of squared market shares; and,
- Generation price setting - identifying the firms that set the Single Marginal Price (SMP) in a given trading period.

[35] Based on Twomey, Green, Neuhoff & Newbery (2008), Table 1; Twomey, Green, Neuhoff and Newbery (2009), “A Review of the Monitoring of Market Power: The Possible Roles of Transmission System Operators in Monitoring for Market Power Issues in Congested Transmission Systems”, published by the Center For Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA, USA; reprinted from Journal of Energy, Literature, Vol. 11, No. 2, pp. 3-54, 2005.
http://web.mit.edu/ceepr/www/publications/reprints/Reprint_209_WC.pdf

[36] Note that in order to accurately identify market power in changing market conditions, the definition of RSI needs to be more dynamic; it should be calculated using available or offered capacity, not installed capacity.

5.3.2 The first three of these (market shares, RSI, HHI) are usually used as long-term, ex-ante metrics within the taxonomy of market power detection methods explained above, although they can also be used as short-term metrics. They primarily focus on market structure; while the last metric—generator price setting—can be considered a market conduct metric (if the focus on individual generator's behaviour) or a market performance indicator (if the objective is to assess whether the market price is negatively affected by the price-setting generators).

Residual / Pivotal Supply Index

5.3.3 RSI uses a continuous scale to examine whether a generator is 'pivotal', to inform an assessment of the potential for a generator to exert market power as the market develops in the chosen scenarios. It is calculated as follows:

RSI = (System capacity (including import capability) – Uncommitted capacity of investigated generator) / demand

5.3.4 Pivotal Supply Index (PSI) measures whether a given generator or generation owner is pivotal in serving demand, where demand may include the capacity need to meet the reserve requirement. If demand cannot be met without the generator, then it is deemed pivotal. Thus, PSI is a binary indicator (i.e., a generator is either pivotal or not). The general formula of PSI is as follows:

PSI = 1 if System capacity (including import capability) – Uncommitted capacity of investigated generator < demand
= 0 otherwise

5.3.5 PSI may be calculated for a single generator (to detect the potential for unilateral market power) or for multiple generators that could jointly exercise (multilateral) market power.

5.3.6 Uncommitted capacity here is the part of total capacity that has not been contracted forward, and requiring an increase in the RSI for the investigated generation owner is equivalent to requiring an increase in its contract cover. RSI is evaluated against a threshold. For example, if the planning reserve margin is 15%, then RSI may be evaluated against a threshold of 1.15. Whenever the investigated generation owner's RSI is less than this threshold, it is required to meet demand and the reserve requirement, and thus is pivotal. RSI is the preferred metric among structural metrics (e.g., HHI, PSI) because it addresses the shortcoming of some of the other metrics, such not taking market demand into account, or ignoring contracted positions of generators.

5.4 MARKET POWER METRICS IN OTHER JURISDICTIONS

5.4.1 A broad range of market power metrics have been applied in electricity markets of other jurisdictions and have been considered by the SEM Committee for I-SEM. Table 5.2 below summarises these metrics by type, with some general comments regarding their strengths, weaknesses, and potential applicability.

Table 5.2: Classification of market power detection metrics in electricity markets

Metric	Type	Comments
Market structure metrics		
Market shares **HHI**	ex-ante	• Commonly used and simple to calculate, but little theoretical justification for relevant competitive thresholds; • Ignores the demand side of the market (when measured based on generation capacity); • Generally not suitable to assess dynamic market conditions when using generation capacity without taking into account availability; therefore, serves best as a descriptive metric.
RSI **PSI**	ex-ante ex-post	• Better suitable than HHI to track market power in dynamically changing markets; • Explicitly incorporate demand conditions; • RSI is continuous index; PSI is binary; therefore RSI is more suitable for measuring the evolution of market power over time, while PSI can serve as a trigger for mitigation.
Residual Demand Analysis[37]	ex-post	• Measures the incentive of a firm to exercise market power by examining the elasticity of a generator's residual demand curve as an indicator of potential market power; • Requires detailed offer data; • Generally it can only be conducted ex post.
Market conduct/behavioural metrics		
Mark-up indices	ex-post	• Includes, Lerner Index (LI), defined as (P – SRMC)/P; and Price-Cost Margin Index (PCMI), defined as (P – SRMC)/SRMC, where P is market price; • System mark-up: mark-up applied by the marginal generator.

[37] For an example of residual demand analysis, see http://www.caiso.com/Documents/ResidualDemand--example.pdf.

Metric	Type	Comments
Withholding analysis	ex-post	• May includes audits of outages and derates, as well as withholding through falsely declared generator parameters (e.g. ramp rates, start-up times, minimum runtimes); • Verifying all events and all parameters may require significant effort; • Requirement to truthfully declare outages, derates, and generator parameters could be implemented as a licence condition; with fines for non-compliance.
Market performance metrics		
Net revenue	ex-post	• Measures "market health", including long-run considerations such as incentives to enter and exit the market; • As with mark-up indices, determining the true SRMC may not always be straightforward; • Metric is affected by other factors, e.g. excess of existing capacity; therefore should be interpreted in context.
Liquidity measures	ex-post	• Includes a number of measures, such as, volume of trade in a market relative to the underlying physical demand (churn rate), number of market participants, etc.; • Not a useful measure to draw conclusions about market power; liquid markets may not be competitive, and vice versa, illiquid markets may produce competitive outcomes.

5.4.2 Market shares, HHIs, and liquidity measures are common metrics used to assess the level of competition in electricity markets in Europe and elsewhere. In some consultations on market competition, Ofgem has used the PSI and RSI metrics. In the ongoing Energy Market Investigation, the UK Competition and Markets Authority (CMA) has applied, on an ex-ante basis, the Residual Demand Analysis to determine whether the GB wholesale market is competitive.

5.4.3 In the PJM wholesale market, the market monitor considers mark-up indices and net revenue measures as the most important ex-post metrics of market participant conduct and market performance. In addition, PJM has implemented an ex-ante, automated mitigation of offers in the day ahead and the balancing markets, when generators are deemed to have local market power, based on a version of PSI known as the Three Pivotal Supplier Test.

5.4.4 Lastly, withholding analyses, including audits of forced outages, are commonly applied in US wholesale markets.

5.5 PROPOSED I-SEM METRICS

5.5.1 The SEM Committee proposes to use a combination of metrics for the relevant I-SEM markets/trading periods (as defined in section 3). This combination is shown below, along with the potential role of each of the metrics in an overall market power mitigation strategy as discussed later. It should be noted that forwards is not referenced as it is considered largely out of scope as discussed in sections 4 and 8.

Table 5.3: Proposed role of market power metrics in I-SEM

Metric	Type	Applicable markets	Role within broader I-SEM market power strategy
Market Structure Metrics			
Market shares **HHI**	Ex-ante	BM, IDM, DAM	• To be used as a descriptive metrics by MMU in its regular reporting. • May be used to determine FCOs.
Residual Supply Index (RSI) **Pivotal Supplier Indicator (PSI)**	Ex-ante Ex-post	BM, IDM, DAM	• RSI to be used by the MMU for ex-ante determination of the expected level of market power. • RSI/PSI could be used for ex-ante mitigation in the BM. • May be used to determine FCOs.
Residual Demand Analysis	Ex-post	BM, IDM, DAM	• To be used on an ad hoc basis by the MMU to conduct ex-post investigations when significant market power concerns arise.
Market Conduct Metrics			
Mark-up indices	Ex-post	BM, IDM, DAM	• Generator mark-up over its SRMC and system mark-up (applied by the marginal generator over its SRMC) to be monitored by the MMU and included in its regular reporting. • Applied by the MMU as part of ex-post enforcement.
Withholding analysis	Ex-post	BM, IDM, DAM	• The MMU should conduct (random) audits of outages and derates, as well as withholding through falsely declared generator parameters (e.g. ramp rates). • Applied by the MMU as part of ex-post enforcement.
Market Performance Metrics			

Metric	Type	Applicable markets	Role within broader I-SEM market power strategy
Net revenue	Ex-post	BM, IDM, DAM	• Generators' net revenue and system mark-up (applied by the marginal generator over its SRMC) to be routinely monitored by the MMU and included in its reporting. • Applied by the MMU as part of ex-post enforcement.
Liquidity measures	Ex-post	All	• The MMU should conduct (random) audits of generator outages and derates, as well as withholding through falsely declared generator parameters (e.g. ramp rates). • Applied by the MMU as part of ex-post enforcement.

5.6 CONSULTATION QUESTIONS

5.6.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

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

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

6 ESTIMATE OF I-SEM MARKET POWER

6.1 INTRODUCTION

6.1.1 Modelling has been undertaken by the RAs to provide a high-level assessment of the potential level of system-wide structural market power in relevant trading periods/markets in the I-SEM over the coming decade. The modelling exercise has considered market developments, including future generation, interconnection, demand and fuel price scenarios.

6.1.2 As described in section 5, the market power analysis framework relies on three main components: Structure, Conduct and Performance - the SCP paradigm. This modelling exercise is meant to provide a view of how the market structure may develop in future years, i.e. for the Structure component of the SCP framework. This then feeds into the market power mitigation proposals and options discussed in section 8.

6.1.3 Of course the future Conduct of market participants and the Performance of the market as per the SCP paradigm is hard to predict, and any proposed market power mitigation for I-SEM will also need to take into account of these aspects of the market power analysis.

6.2 MODELLING SCENARIOS

6.2.1 The RAs have taken a conservative modelling approach to identify an upper bound on the likely extent of structural market power in I-SEM, for example by using a high demand forecast, and assuming a lower bound on the closure of generation by market participants with high market share. The scenarios modelled included:

- Expected market conditions in the SEM in 2016 (reflecting current generation portfolio and interconnection capacity)—this serves as a baseline for the future I-SEM scenarios;

- Expected market conditions in the I-SEM in 2019; and,

- Expected market conditions in the I-SEM in 2024.

6.2.2 The scenarios reflect forecast demand and generation capacity from the All-Island Generation Capacity Statement 2015-2024[38]. The main base case scenario assumptions are listed in the table below. Apart from the system data and the installed capacity of wind, the main differences between the

[38] http://www.eirgrid.com/media/Eirgrid_Generation_Capacity_Statement_2015.-2024.pdf

years are down to discrete events such as the closure of generation plants or the commissioning of new plants.

Table 6.1: Base case scenario assumptions

Year	2016	2019	2024
Demand	Current model	High demand forecast as per GCS 2015-2024	
Dispatchable generation	Existing	Two new plants: Dublin waste to energy plant (62MW) + New OCGT plant (98MW)	
Plant retirements	None	Ballylumford (B4, B5 & B6) - 250 MW	Tarbert (592 MW) Kilroot Coal (476 MW)
Wind[39]	Current model	Wind installed capacity as per GCS 2015-2024, allocated proportionally to wind regions based on current regional capacities. Ownership share is assumed unchanged in all years.	
Interconnection	Existing (Moyle derated)	Existing (EWIC + Moyle restored at full capacity)	

6.2.3 Wind generation output is determined using a typical year's wind profile (currently used in the model) uplifted for the increases in installed wind capacity. This produces a wind generation figure for each half-hourly period during the year.

6.2.4 Additional sensitivities that have been tested include:

- An alternative scenario for 2024 with an additional 500 MW of interconnection with the GB market;
- An alternative scenario for 2024 where two additional gas-fired generating units, which we have assumed will be owned by a new entrant, with a total capacity of 412 MW are considered as well as the additional 500 MW interconnector with GB; and ,
- Alternative fuel price scenarios for 2019 and 2024 where increased availability of relatively inexpensive natural gas (for example, due to shale gas exploration) results in low gas prices causing some gas-fired plants to replace coal plants in the merit order;

6.2.5 All scenarios have been modelled using the RAs' Validated SEM PLEXOS Forecast Model. Please see Appendix D for detailed information on the modelling assumptions made in this analysis.

[39] Company ownership ratio of wind is based on estimates for 2014.

6.2.6 For clarity, the modelling results presented do not take any forward contracting into account - to the extent that market participants do contract forward the results of the structural market power metrics would be different.

6.3 METRICS AND TRADING PERIODS FOR MODELLING

6.3.1 The analysis for each scenario consists of calculating market shares and pivotality metrics - the PSI and the RSI - to assess the potential for the exercise of structural market power in I-SEM, based on the market structure component of the SCP paradigm (referred to earlier), by individual generation owners. The analysis was conducted for each half-hourly period of the dataset being investigated but annual averages are also reported. HHIs were also calculated to give an indication of the trends in the market structure across the scenarios.

6.3.2 Market shares represent the simplest indicator of the ability to exert structural market power, since they are relatively easy to calculate, transparent and readily understood. Market shares have been calculated based on both ownership of generation capacity and actual energy dispatched.

6.3.3 Market conditions and dynamics in each of the forward and physical trading periods are likely to be different such that any modelling of structural market power can only provide a high-level assessment of expected levels of structural market power by capturing a snapshot of market conditions in a particular time frame. The average RSIs by generator and the HHI for the overall market were calculated to give an indication of the general trend across scenarios.

6.3.4 Pivotality metrics are generally the preferred metrics for assessing structural market power in electricity markets as they also reflect the degree to which (largely) inelastic demand can be met without the capacity of a particular generator. The RSI analysis sets out the frequency of periods in which the system is not able to balance supply with demand without the supply of the 'investigated' market participant. For each scenario, we considered the individual position of the largest generator (typically ESB) and the combined position of the two largest generators (the two pivotal supplier test).

6.3.5 The RSI is calculated for each company by summing all the available capacity of all other companies in I-SEM, all the output of wind generation and the full capacity of the interconnectors. This is then divided by the total demand, which is the all-island customer demand plus demand from pumped load and any interconnector exports. This differs from the calculation of generation market shares which include the output from wind capacity owned by each company.

6.3.6 Strictly speaking, if the RSI is below 1 (or 100%) then the capacity of the generator is necessary to meet the next MW of demand (the generator is pivotal as measured by the PSI). However the RSI measure also allows the use of a higher threshold to reflect the need for additional spare generation capacity, for example to allow the TSOs to meet a certain operational reserve margin.

6.3.7 To reflect this need for additional spare capacity we have used in our analysis an RSI threshold of 1.2 to identify periods when competition in the market is limited. This is consistent with a previous assessment of structural market power in the SEM, in which CEPA[40] noted that, whilst there are no consensus rules as to what the critical value should be, empirical studies in California suggests an RSI above 1.2 would result in a competitive market price outcome. In addition to this the studies[41] undertaken as part of the European Commission Sector enquiry highlighted a critical value of at least 1.10 for 95% of the periods observed.

6.3.8 This modelling has assessed the expected level of structural market power in the I-SEM DAM and the BM. The IDM is not shown explicitly; however when trading in the IDM takes place, for example, close to 12 hours (or more) ahead of delivery market conditions are likely to be very similar to those experienced in the DAM. When IDM trading takes place close to gate closure, market conditions are more likely to resemble those seen in the BM. Therefore, the SEMC believes that the results of the DAM and BM modelling are representative of the likely structural market power in the IDM also.

6.4 RESULTS FOR DAY AHEAD MARKET

6.4.1 The PLEXOS algorithm optimises the economic dispatch such as to minimise system costs. The unconstrained PLEXOS model should thus produce a market schedule approximating the DAM schedule in the I-SEM.

Base Case Market Share - 2016, 2019, 2024

6.4.2 The modelling results for 2016 largely reflect current market conditions, with ESB having the largest market share in terms of both ownership of installed capacity and generation output as shown in the table below. SSE and AES have similar capacity market shares but SSE holds higher generation market share. BGE has a similar generation market share to AES but has much lower share of capacity. Overall HHI is measured at 2,617.

[40] The 2010 CEPA report for the RAs: "Market Power and Liquidity in the SEM" (December 2010).
[41] European Commission, DG COMPETITION REPORT ON ENERGY SECTOR INQUIRY (January 2007).

Table 6.2: Average market shares for 2016

Market participant	Capacity market share	Generation market share
ESB	44.4%	46.6%
SSE	13.5%	14.1%
AES	13.2%	7.2%
BGE	4.7%	7.0%
BnM	2.5%	4.3%
Aughinish	1.8%	3.8%
Viridian	8.1%	1.9%
Power NI	6.3%	1.3%
Tynagh	4.1%	0.4%
GB import	n/a	5.9%
Independent wind	n/a	6.7%
Others	1.3%	0.8%
HHI	**2,484**	**2,617**

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

6.4.3 Similar to 2016, ESB is the largest market participant in 2019 for both capacity and generation. SSE is still the second largest player in the generation market while AES has a fall in its capacity market share due to the expected decommissioning of three units at Ballylumford. This also results in a small increase in the market shares of the other market players including ESB and SSE. Extra wind capacity results in an increase in wind output. The share of total wind (owned by companies with conventional generation and independent wind generators) generation output increases to 31% in 2019. The expected return of the Moyle interconnector to full capacity also results in an increased role for GB imports in 2019. The generation HHI has reduced from 2617 in 2016 to 2,237 by 2019.

Table 6.3: Average market shares for 2019

Market participant	Capacity market share	Generation market share
ESB	46.1%	42.0%
SSE	14.0%	14.9%
AES	8.1%	5.7%
BGE	4.9%	7.8%
BnM	2.6%	4.4%
Aughinish	1.8%	3.5%

Market participant	Capacity market share	Generation market share
Viridian	8.5%	1.5%
Power NI	6.6%	1.0%
Tynagh	4.3%	0.3%
GB import	n/a	8.8%
Independent wind	n/a	8.1%
Others	3.1%	1.9%
HHI	**2,558**	**2,237**

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

6.4.4 In 2024, the expected decommissioning of the Tarbert plants in the Republic of Ireland and the Kilroot coal plants in Northern Ireland leads to the loss of more than 1,000 MW of dispatchable generation capacity in the I-SEM compared to 2019. In the base case scenario, only 160 MW of dispatchable generation capacity is expected to be added in the I-SEM compared to the 2016 scenario (a 62 MW waste energy plant and a 98 MW OCGT plant). The decommissioning of AES and SSE-owned generation capacity means that ESB's capacity market share is likely to increase in 2024 to around 52%. However greater wind contribution (36.9%) results in an ESB generation market share reduction to just over 30%. The generation HHI has reduced considerably from previous years, to 1,667, a level for the market that could be considered only moderately concentrated[42].

Table 6.4: Average market shares for 2024

Market participant	Capacity market share	Generation market share
ESB[43]	52.3%	30.3%
SSE	8.4%	19.1%
BGE	5.6%	12.5%
AES	3.2%	0.0%
BnM	2.9%	4.9%
Aughinish	2.1%	3.4%
Viridian	9.6%	2.6%

[42] The modelled capacity margin is lowest in 2024 due to the combined assumptions of high demand growth and the single set of assumptions used around station retirements and entry, which results in a net reduction in installed capacity. This may not be considered a likely scenario but was considered appropriate for structural market power modelling in this context.
[43] Assumes the peat stations remain available but dispatched on the basis of the fuel price for peat, and that the Dublin Bay power station bids using the day ahead cost of gas.

Market participant	Capacity market share	Generation market share
Power NI	7.5%	1.8%
Tynagh	4.9%	2.2%
GB import	n/a	11.7%
Independent wind	n/a	9.6%
Others	3.5%	1.9%
HHI	**3,036**	**1,667**

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

Base Case RSI - 2016, 2019, 2024

6.4.5 While the market share metrics shown above give a good indication of the ownership of generation capacity, the RSI gives a better indication of whether the capacity of a particular player is necessary to meet demand and thus whether it has the ability to exercise market power. Note that a company's wind capacity is not included in this calculation, whereas it is included in the previous figures on generation market share. The average RSI by company is presented in the following tables which allows comparison of companies that fall under the RSI thresholds (1 or 1.2) and those that don't.

6.4.6 In the figures below we show the individual RSI curves of the two largest players (by generation market share) as well as the combined RSI of the two largest players for each year modelled. Factors that affect RSI over time are demand growth, change in forecast wind generation output, and changes in generation ownership (either though investment in new generation or closure of existing generation plants) by owners other than the company for which the RSI is being calculated

6.4.7 The RSI curves show the percentage of half-hourly periods in the year when the RSI is lower than a given level. For example, the RSI ESB line in the 2016 RSI figure crosses the "1.2" line at the 9% mark. This indicates that the available capacity in the market after taking away the ESB available capacity is less than 120% of demand in around 9% of half hourly periods in the year. Similarly the ESB RSI is below 1 around 0.7% of the time. In these periods there isn't sufficient non-ESB generation capacity in the market to meet demand (even if all reserves are used).

6.4.8 The RSI curve for SSE, the second largest market player in 2016, has also been plotted in the figure below. Except ESB however, no other market player's individual RSI falls below the 1.2 threshold in any of the half-hourly periods.

6.4.9 In addition, we have also calculated the combined RSI for the two largest generators in the market for each half hourly period to account for the possibility of exercising structural market power through collusion between market participants. Given that the largest generation capacity is held by ESB in every period, this means calculating an RSI where the capacity of both ESB and of the next biggest player is unavailable. In this case, the combined capacity of the two largest generators is necessary to meet the 1.2 threshold over 40% of the time.

6.4.10 The average RSI in table 6.5 shows that ESB is 30% below the next largest company, SSE and that taken together they are just 9% above the threshold of 1.2 throughout the entire year.

Figure 6.1: RSI curve 2016 (base case scenario)

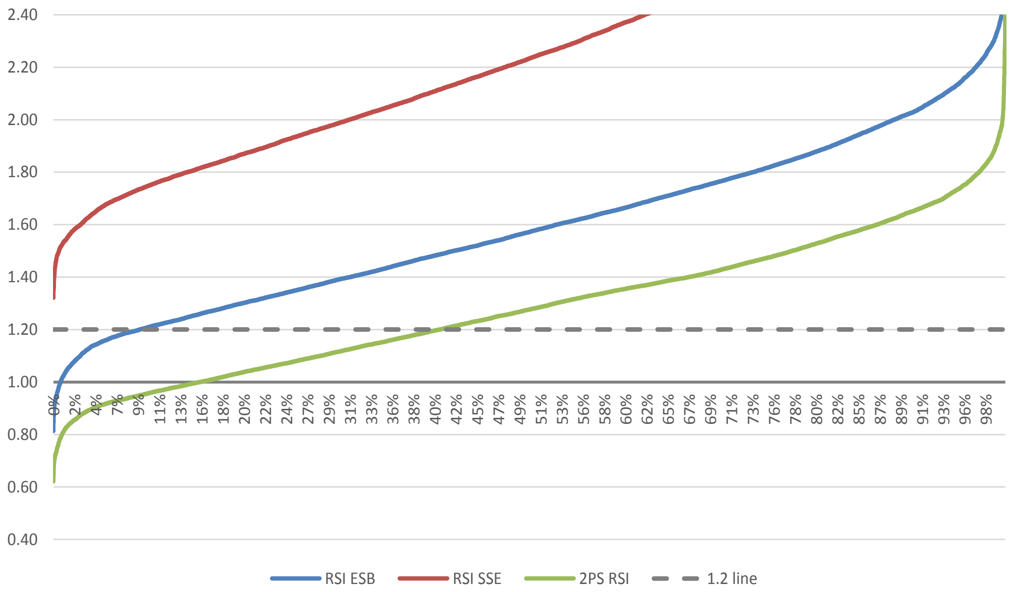


Table 6.5: Expected percentage of time when RSI is below threshold (2016)

Company	% half hourly periods		Average RSI
	RSI < 1.2	RSI < 1	
ESB	9.1%	0.7%	1.60
SSE	0.0%	0.0%	2.27
2PS	40.6%	15.4%	1.29

6.4.11 The 2019 scenario measures the expected level of structural market power shortly after the implementation of the I-SEM. Similar to 2016, ESB is the only pivotal player in the market. However the percentage of time when ESB's RSI falls below the 1.2 threshold increases in 2019 to 12.5% of all half-hourly periods. This increase is driven primarily by demand growth and the decrease in conventional generation capacity.

Figure 6.2: RSI curve 2019 (base case scenario)

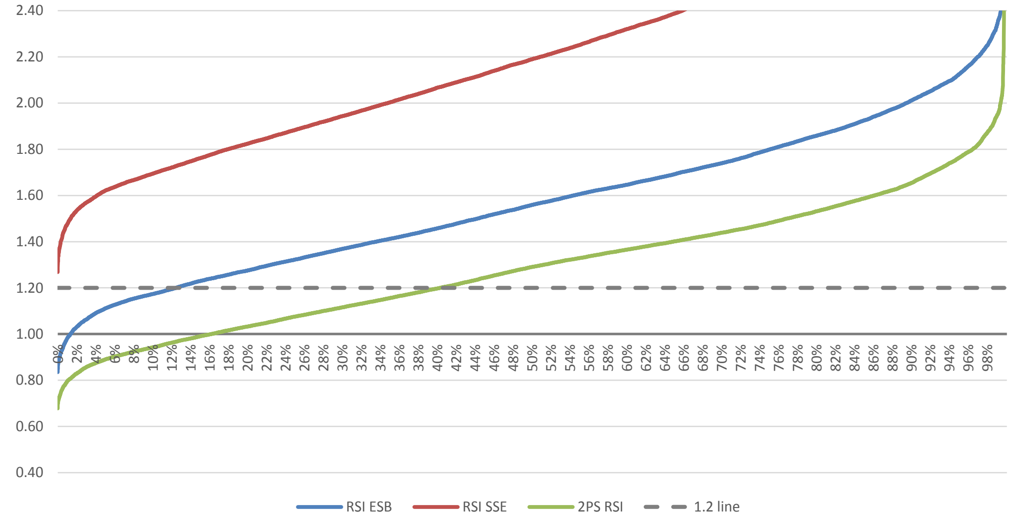


Table 6.6: Expected percentage of time when RSI is below threshold (2019)

Company	% half hourly periods		Average RSI
	RSI < 1.2	RSI < 1	
ESB	12.5%	1.3%	1.57
SSE	0.0%	0.0%	2.22
2-PS	40.4%	16.2%	1.29

6.4.12 The 2024 RSI curves show that the expected potential for exercising structural market power is likely to be even greater in 2024 with ESB's RSI being below the 1.2 threshold 37.5% of the time.

Figure 6.3: RSI curve 2024 (base case scenario)

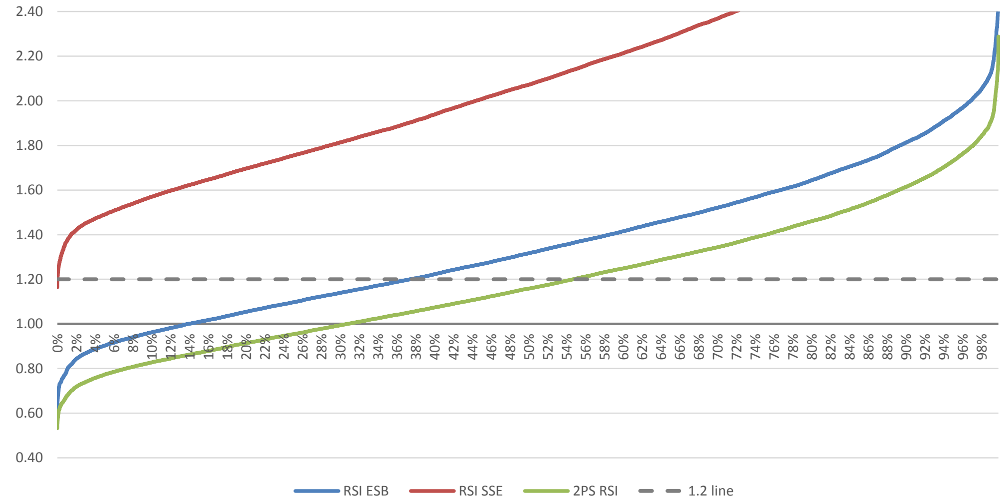


Table 6.7: Expected percentage of time when RSI is below threshold (2024)

Company	% half hourly periods		Average RSI
	RSI < 1.2	RSI < 1	
ESB	37.5%	13.9%	1.35
SSE	0.02%	0.00%	2.13
2-PS	54.8%	30.8%	1.19

6.4.13 The closure of AES and SSE owned power plants at Tarbert and Kilroot means there is less conventional generation capacity to meet higher levels of demand. An increasing share of electricity generation in 2024 will be provided by wind. The intermittent nature of wind generation means however that while there will be periods during the year when wind will be providing a high proportion of energy demanded in the I-SEM, remaining demand will have to be met by conventional generation capacity and imports over the interconnector.

6.4.14 Increases in demand and decreases in conventional generation capacity over the coming decade mean that the conventional capacity available to meet demand in low wind periods is likely to be smaller in 2024 resulting in a higher number of periods when ESB is pivotal. This is confirmed by the relatively strong correlation (0.7 in 2024) between the share of wind generation and ESB's RSI (i.e. periods of low wind penetration tend to coincide with periods of low RSI).

Alternative Scenarios – 2024

6.4.15 Several additional scenarios were examined for 2024, including an additional 500 MW interconnection capacity with GB and two new gas-fired power plants, owned by a new entrant, with a combined capacity of 412 MW capacity. The results of these scenarios are shown below, starting first with market share and HHI results and then showing the RSI results.

6.4.16 The additional 500MW interconnector results in a sharp increase in imports from GB to 19.6% (from 11.7%) and a decrease in the generation market share of I-SEM generating units. The further addition of two new I-SEM gas-fired power plants results in a further drop in the market share of the largest market participants. ESB's generation market share falling to just below 26% in this scenario and the overall HHI falling to 1,386.

Table 6.8: Average market shares for 2024 (with additional interconnector)

Market participant	Generation market share
ESB	26.8%

Market participant	Generation market share
SSE	18.3%
AES	0.0%
BGE	10.7%
BnM	4.9%
Aughinish	3.5%
Viridian	2.3%
Power NI	1.4%
Tynagh	1.0%
GB import	19.6%
Independent wind	9.6%
Others	1.9%
HHI	**1,386**

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

Table 6.9: Average market shares for 2024 (with additional interconnector and new gas-fired plants)

Market participant	Generation market share
ESB	25.7%
SSE	18.1%
AES	0.0%
BGE	10.2%
BnM	4.9%
Aughinish	3.5%
Viridian	2.1%
Power NI	1.2%
Tynagh	0.6%
GB import	20.5%
Independent wind	9.6%
Others	3.5%
HHI	**1,313**

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

6.4.17 The additional interconnector and new power plants increase the capacity available to meet the same level of demand compared to the 2024 base case scenario. This has the effect of lowering the number of periods when a particular player is pivotal.

6.4.18 Compared with the 2024 base case scenario, the percentage of time ESB's RSI is below 1.2 falls from 37.5% to almost 17%. However this still represents a level of structural market power higher than the level of structural market power indicated by the RSI metric in 2016.

Figure 6.4: RSI curve 2024 with additional 500MW interconnector with GB

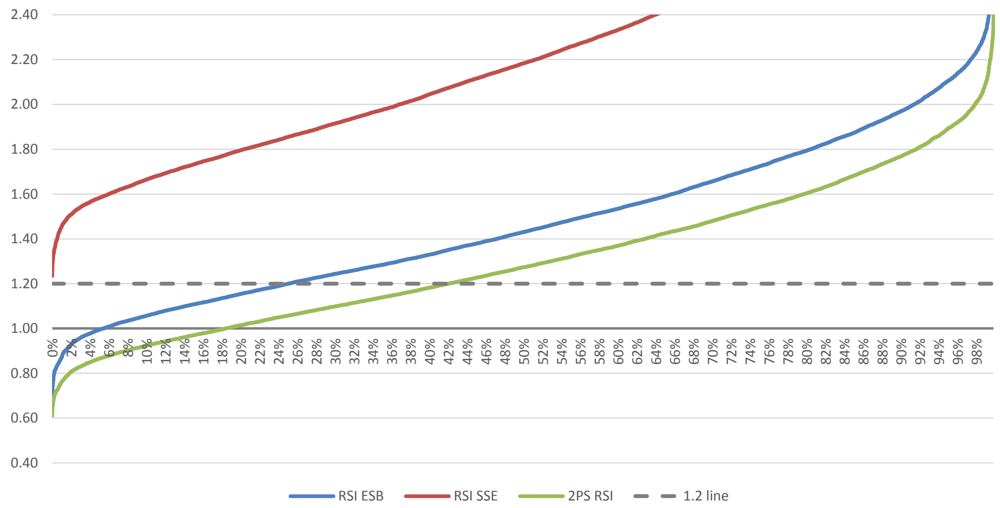


Table 6.10: Expected percentage of time when RSI is below threshold (2024 with additional interconnector)

Company	% half hourly periods RSI < 1.2	Average RSI
ESB	25.1%	1.47
SSE	0.0%	2.25
2PS	42.1%	1.31

Figure 6.5: RSI curve 2024 with additional 500MW interconnector and new gas-fired power plants

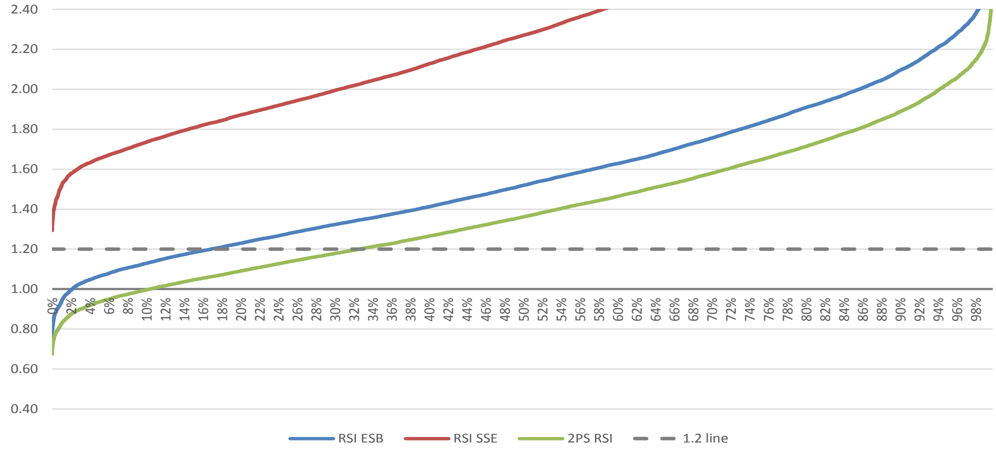


Table 6.11: Expected percentage of time when RSI is below threshold (2024 with additional interconnector and new gas-fired power plants)

Company	% half hourly periods RSI < 1.2	Average RSI
ESB	16.9%	1.57
SSE	0.0%	2.35
2PS	32.7%	1.40

6.4.19 All the scenarios for 2019 and 2024 presented above have also been run using an alternative fuel price scenario. This is based on the assumption that gas prices will decline significantly in the coming years such that gas-fired generators will displace coal plants in the merit order.

6.4.20 Given that the total capacity available in the DAM is not impacted by fuel prices, this scenario has little impact on the expected level of structural market power in the DAM as measured by the RSI.

6.4.21 It will however have an impact in terms of the units which are dispatched such that generators using gas-fired power plants will have a higher a market share than under the base case scenario at the expense of generators relying more heavily on coal-fired plants.

6.4.22 The table below shows the generation market shares for the biggest market players. In the relative low gas price scenario the generation market share of ESB for example will decline more rapidly. In 2019, ESB's expected market share reaches 33.5% compared to 42% in the base case scenario, while in 2024 its market share falls to 24.6% compared to 30% in the base case scenario. In contrast the market shares of SSE and BGE increases by over 3% (in 2019) and below 2% (in 2024) in the base case scenario under the alternative fuel price scenario.

Table 6.12: Average generation market shares (low relative gas price scenario)

Market participant	2019	2024
ESB	33.5%	24.6%
SSE	18.3%	19.7%
BGE	10.9%	14.4%
AES	0.1%	0.0%
BnM	4.5%	4.8%
Aughinish	3.5%	3.4%
Viridian	2.5%	3.2%
Power NI	2.7%	3.3%
Tynagh	4.2%	4.9%
GB import	9.8%	10.3%
Independent wind	8.2%	9.4%
Others	2.0%	2.0%
HHI	**1,784**	**1,449**

Note: Generation market shares include both GB imports and wind generation. Company market share include an estimate of company wind.

Non-Structural Market Power

6.4.23 The increased importance of intermittent wind generation, which is priority-dispatched, means that the range of potential price setting plants will increase. For example, plants, which are typically baseload, may become price setters in periods of high wind output. This may also result in larger price swings across the different periods and can have implications for the potential to exercise market power of even the players that do not have structural market power.

6.4.24 To illustrate this, we have considered the number of periods during a year when a small generator could be expected to be the marginal price-setting generator in the DAM. We have conducted this analysis for 2024 by estimating a generation supply curve based on each generating unit's SRMC. For each half-hourly period, we have determined which is the expected price-setting generator based on the estimated demand level and wind output for that period and assuming the maximum installed capacity of each generator is available. The results show that, on aggregate, these units could be expected to act as the price-setting generator over 7% of the time, as shown below.

Table 6-13: Estimated price-setting generator

Generator	Ballylumford B31 & B32	Whitegate
% periods	1.4%	6.0%

6.4.25 Based on the differences between the SRMC of each of these units and the SRMC of the next unit in the merit order, we have estimated the uplift that these units could apply to the DAM market price. The relative steepness of this portion of the supply curve means that there could be potential for these units to exercise market power during certain times of the year, i.e. to engage in financial withholding.

6.5 RESULTS FOR BALANCING MARKET

6.5.1 In the I-SEM, the BM will run concurrently with the IDM, from approximately 13:30. The IDM will end at gate-closure, and the BM will continue until real-time[44]. Given the characteristics of electricity networks, the supply/demand situation and market conditions will change on a continuous basis during the functioning of the BM. Transmission constraints may mean that localised market power can arise, and move over a specific power station who is uniquely able or necessary to maintain the system frequency.

6.5.2 For the purposes of assessing the expected level of market power in the I-SEM, market conditions in the BM at IDM gate closure (one hour ahead of delivery) have been considered. This is consistent with the expectation that the TSOs will refrain as much as possible from undertaking energy actions before the IDM gate closure.

6.5.3 The BM has been modelled by assuming an unexpected balancing need that the TSOs need to fulfil one hour ahead of delivery. This balancing need could arise for example due to a wind forecast error or an unexpected shift in demand and has been modelled as a 10% increase in the demand level in each half-hourly period.[45] The generating capacity available to meet this balancing need has been determined by taking into account the level of committed generation based on the market schedule quantities determined

[44] While gate-closure will be one hour ahead of real-time, there may be an earlier gate-closure during a transitional phase which will last no more than 12 months. The decision on this will be made closer to I-SEM go-live. If an earlier gate closure is chosen, it will be no earlier than four hours before real-time.

[45] This assumption means that balancing volumes used to calculate market power metrics change dynamically depending on demand in each half hourly period. For example, in 2024 balancing volumes vary between around 250 MW and 700 MW.

through PLEXOS and the remaining generating units' operational constraints (e.g. start times and ramp rates).[46]

6.5.4 This analysis is meant to illustrate how shorter-term supply-demand conditions might look for energy actions in the balancing market and ignores non-energy actions and local market power.

6.5.5 The table below shows the results of the RSI analysis on the balancing market under the base case scenarios. Due to the short-term nature of the BM, different generators will be available to meet balancing demand in different periods. The RSI of the largest player (1PS) in each period is reported as well as the RSI of the two largest players (2PS). For example, the results indicate that in 2016, the largest capacity holder in the modelled balancing timeframe will be pivotal 64.9% of the time. The analysis shows that this figure is likely to vary in future years. The combined RSI of the two largest generators in the balancing market increases in both 2019 and 2024 while the RSI of the largest player in the balancing market shows a decrease in 2019 followed by a sharp increase in the 2024 scenario.

Table 6-14: Expected percentage of time when RSI is below 1.2 threshold and largest capacity holders in BM

Market participant	2016	2019	2024
1PS	64.9%	62.2%	72.8%
2PS	87.5%	89.7%	94.9%
Largest capacity providers (% of half hourly periods)			
ESB	34%	36%	64%
SSE	10%	7%	2%
AES	7%	9%	0%
BGE	14%	11%	6%
POWERNI	8%	6%	4%
Tynagh	5%	4%	7%
Viridian	6%	6%	4%
GB Gen	16%	22%	13%

6.5.6 These results are largely due to the same factors driving the results in the day ahead market, i.e. higher demand and lower conventional generation capacity. In addition, a third factor that may lead to tighter market condition

[46] For generators "in-merit" in the DAM, the capacity available for dispatch in the balancing market equals total generation capacity minus generation scheduled in the DAM. This is also subject to ramp up constraints.

in the BM is the fact that in periods with high wind penetration many conventional generating units will not be dispatched. As most of these units are unlikely to be able to start at short notice there will be a loss of capacity available for the BM compared to a situation where such units would be dispatched but still have some spare capacity which they could supply at short notice (subject to ramp constraints).

6.6 IMPLICATIONS OF RESULTS

6.6.1 The modelling analysis indicates that ESB has the largest market share in installed capacity in 2016 at circa 44% and this is likely to increase somewhat in following years due to expected plant decommissioning by other market participants. However ESB's generation market share is likely to diminish significantly over the years as wind penetration increases and non-ESB conventional generation capacity closes, with the generation share falling from around 47% in 2016 to around 30% in 2024 - for clarity the results do not represent a linear progression between the years modelled.

6.6.2 In contrast the percentage of half hours when the RSI is below 1.2, the threshold that typically suggests structural market power potential, will increase. For ESB it increases from 9% in 2016 to around 37% in 2024 due to a fall in non-ESB conventional generation capacity, increased intermittent wind generation and higher demand levels. A similar trend can be seen for the 2-pivotal player (2PS) test. This will be particularly the case when high demand periods coincide with low wind generation periods.

6.6.3 Table 6-15 shows the contrasting results coming from the two structural measures of market power - the HHI and the RSI - over the years modelled. The rising share of wind generation and ESB's falling market share results in a declining HHI - and hence structural market power - between 2016 and 2024. However, ESB's average RSI falls over the same period as a result of the increasing wind and market exit experienced over the period, which indicates increasing market power concerns.

Table 6-15: Summary of market structure metrics in the day-ahead market

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

6.6.4 This modelled divergence between a reducing HHI such that the market could be considered only moderately concentrated by 2024, while RSI on average is decreasing indicating increased potential for structural market power at certain times only, needs to be taken into account when developing an I-SEM market power mitigation strategy.

6.6.5 The modelling also shows that new interconnection/generating capacity would further mitigate market concentration and therefore the potential to exercise market power; however the expected level of structural market power by ESB will remain significant particularly in periods of high demand and low wind generation.

Table 6-16: Summary of ESB structural market power metrics in the day-ahead market

Market participant	Capacity market share	Generation market share	RSI < 1.2 (% periods)
2016	44.4%	46.6%	9.1%
2019	46.1%	42.0%	12.5%
2024	52.3%	30.3%	37.5%
2024 (with additional I/C)	52.3%	26.8%	25.1%
2024 (with additional I/C and new gas-fired plants)	49.7%	25.7%	16.9%

Note: Capacity market shares exclude interconnection and wind capacity. Generation market shares include both GB imports and wind generation. The ESB generation market share includes an estimate of ESB wind output.

6.6.6 Due to the short-term nature of market conditions in the balancing market, different generators will be available to meet balancing demand in different periods. For example, the results indicate that in 2019, the largest capacity holder in the modelled balancing timeframe will be pivotal in 62.2% of the time, with the two largest players pivotal 89.7% of the time. This suggests that a robust market power mitigation strategy will be particularly important in the balancing market.

6.6.7 Although other players are unlikely to have structural market power in future years, the examples presented in section 6.4 show how even smaller market participants could at certain times have the incentive and ability to exercise market power. This again would need to be considered in a market power mitigation strategy.

6.6.8 The modelling results presented in this section provide a high-level assessment of the potential to exercise market power in future years in the I-SEM based on forecast changes in the I-SEM market structure. These results have been used to inform the I-SEM market power mitigation measures and options laid out in Section 8.

6.6.9 These measures will however necessarily need to take into account the fact that market structure alone is not the only determinant of market power behaviour. As discussed earlier, in certain periods even players that do not have structural market power can find themselves in a position to exercise market power; conduct and performance as per the SCP paradigm in assessing market power are important too in developing the market power mitigation strategy shown in section 8.

6.7 CONSULTATION QUESTIONS

6.7.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

- *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?*

7 REVIEW OF CURRENT SEM MEASURES

7.1 INTRODUCTION

7.1.1 This section examines the performance of market power mitigation measures in SEM, forming a backdrop to the I-SEM mitigation measures proposed later in Section 8.

7.1.2 As a background, the SEM market power mitigation strategy was designed by the RAs to mitigate certain features anticipated in relation to the market structure at the time. The text box below summarises current market power mitigation measures in SEM.

Box 7.1: Market power mitigation measures in SEM

Market Monitoring Unit (MMU

The MM) analyses how the SEM operates in practice in order to safeguard against market failure and potential abuses of market power by market participants.

Bidding Code of Practice (BCoP)

Generator units in the SEM are bound by the bidding principles. Central to the principles of bidding is the BCoP and the associated licence conditions in each jurisdiction. The bidding principles establish a requirement for generators to bid their Short-Run Marginal Costs into the market. The BCoP is published as an annex to the Decision Paper AIP-SEM-14-018. Important excerpts include:

- When calculating the Shor Run Marginal Cost (SRMC) of a generation set or unit in a trading day, constituent cost-items are to be valued at their opportunity cost, so that a reasoned explanation of the calculation of that opportunity cost is capable of being given to the Utility Regulator or CER on request.
- The opportunity cost of any cost-item shall compromise the value of the benefit forgone by a generator in employing that cost item, by reference to the most valuable realisable alternative use of that cost item for purposes other than electricity generation.

There have been several issues explored by the MMU relating to specific cost items in generators commercial offer prices. Because the principles are not explicit numerical rules, there is a degree of judgment required in interpreting them and in monitoring/administering them.

The consultation paper “Market Power Mitigation in the SEM” of 1st February 2006[47] offered the following distinction between bid controls and bidding principles:

- *Bid controls* tell a generator how to bid using a potential algorithm to simulate SRMC; while
- *Bidding principles* allow the bidder to freely submit any bid which may then

[47] AIP/SEM/02/06 and subsequent Decision Paper AIP/SEM/31/06.

be subject to review.

The paper noted the pros and cons of a prescriptive approach vs principles, noting that, 'Too frequent invocation of prescriptive procedures will handicap generators vis-à-vis their competitors to the extent that the prescriptions annul the use of better bidding strategies which more closely represent the true SRMC. But a prescriptive approach may have advantages where local market power requires constant intervention'. On balance, the RAs considered that the use of DCs removed the necessity for prescriptive controls and that bidding principles and monitoring could be lighter handed. The thinking was that bidding principles for SEM would give market participants considerable latitude in determining aspects of marginal costs that require judgement.

Directed Contracts (DCs)

DCs are forward Contracts for Differences (CfDs) used to remove or mitigate the incentives on the incumbents to attempt to profit from the use of market power in the physical spot market by deviating from SRMC bidding. They were introduced at the time the SEM was established, and there was a relatively high level of market concentration in generation. The volumes, pricing and eligibility methodology of the DCs is set by the RAs, and apart from reducing the ability of the main player ESB to take advantage of its spot market power, it also provides an important source of liquidity in the forward market.

Vertical ring-fencing

During the development of the SEM, the RAs jointly decided that, as part of a market power mitigation strategy, vertical ring-fencing between affiliated generating and supply businesses within the ESB and Viridian groups was appropriate.[48] The main purpose of these arrangements was to ensure that, via licences, the businesses of ESB and Viridian operate independently of each other. They feature separate management, separate accounts, as well as a prohibition of anti-competitive behaviour, cross-subsidies (either to or from their affiliate businesses) and contracts with affiliates if they are not on an arm's length basis on normal commercial terms. This applies to both the generation and supply arms of the ESB and Viridian groups. An important part of the licence requirement on ESB PG and for Power NI PPB is the requirement to contract on an arm's length basis and on normal commercial terms only, i.e. it can't offer special terms to favour its affiliates.

Vertical ring-fencing arrangements can potentially enable competition in both the retail supply and wholesale markets by facilitating price formation in the interface between the two activities, and they remove cross-subsidies between business entities, thereby facilitating new entry in the market.

[48] Ring-fencing was specifically referred to in the market power mitigation decision paper. AIP/SEM/31/06. The RAs consulted on appropriate ring-fencing arrangements for incumbent Suppliers in August 2005 (AIP/SEM/74/05) and then briefly again as part of a broader consultation paper in February 2007 (AIP/SEM/07/16) which was then followed by a decision in June 2007 (AIP/SEM/304/07).

Local market power mitigation

Local market power mitigation measures may be applied, as necessary, and may include cost-based Reliability Must Run (RMR) contracts for generators that possess local market power and are needed for system reliability.

7.1.3 A relevant background to this assessment of SEM market power mitigation measures is a previous review which the SEM Committee concluded in February 2012[49]. This found no significant market power exercised in the SEM spot market due to the relevant market power mitigation measures in place. Specifically the review found that the BCoP, MMU and DCs had helped ensure generator bids at competitive SRMC levels, resulting in efficient SEM wholesale prices. The assessment below incorporates and updates on this conclusion of 2012.

7.2 ASSESSMENT OF CURRENT SEM MEASURES

7.2.1 In order to assess the potential applicability of each of the SEM market power mitigation measures in I-SEM, the RAs assessed their historical performance, as follows.

MMU and BCoP

7.2.2 The Market Monitoring Unit (MMU) resides within the RAs and is responsible for monitoring how the SEM market operates in practice, serving as a safeguard against market failure and market power abuses. The MMU is primarily responsible for monitoring:

- Short- and long-term SEM outcomes; and,
- Market participant behaviour;

7.2.3 The MMU reports to the SEM Committee on these matters on an ongoing basis, and publishes internal and public reports. The MMU's work informs the RAs' broader regulatory work. The MMU also acts as the interface with market participants who wish to report on market power, SEM operation, scheduling and dispatch, and related matters.

7.2.4 Since the start of SEM, the MMU has been very active in evaluating compliance with market rules and engaging with market participants. Although formal investigation have been limited in number, informal investigations have been conducted frequently (as many as 10 per week).

[49] Please see: http://www.allislandproject.org/en/market_current_consultations.aspx?article=682a98fe-9c18-4c73-8fa3-57e75d24d85e&mode=author

7.2.5 The main focus of the MMU has been on verifying compliance with SRMC bidding, mandated by the generation licences and BCoP, on an ex-post basis. An analysis of market schedules to identify price-setting generators is conducted on a daily basis, once all the relevant data is received, four days after the operating day. The MMU also conducts a regular assessment which identifies potential differences between the MMU-estimated offers and submitted offers.

7.2.6 The MMU has developed an in-house tool that compares, on an ex-post basis, expected bid/offer profiles with those submitted by market participants. Expected offers are derived using publically available information on fuel costs and generators' technical parameters. Deviations are investigated by the MMU, primarily by seeking an explanation for the observed discrepancy from the generator involved. If it can be demonstrated that a market participant did not adhere to SRMC bidding, then the MMU usually conducts further analysis to assess any potential market power impacts, including local market issues created by transmission constraints.

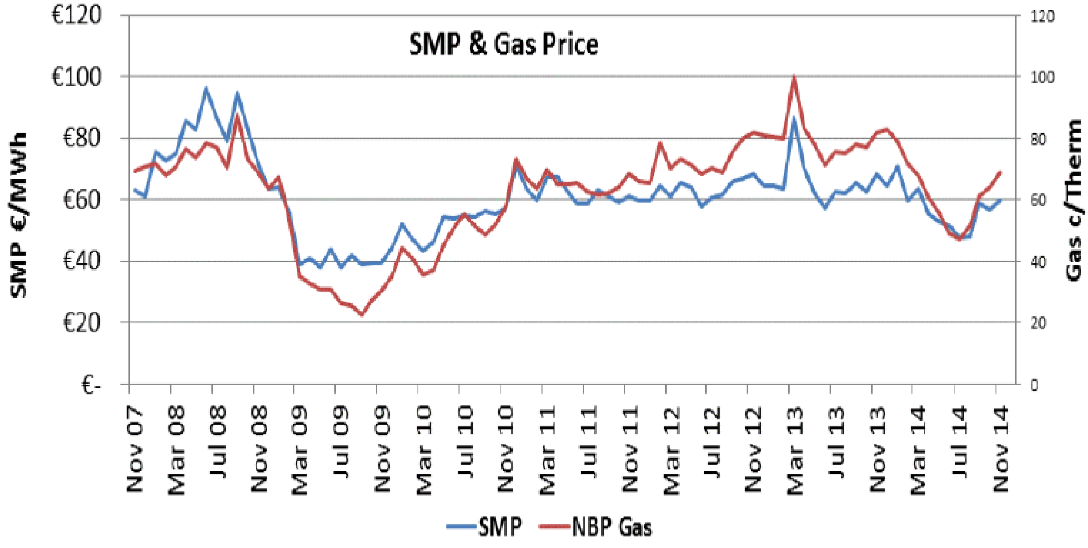
7.2.7 The majority of issues investigated by the MMU have involved a local market power element, in particular submissions of offers in excess of SRMC during periods of constrained operation. Local market power mitigation measures are available on an as-needed basis, but such measures have not yet been formally defined, nor have they ever been invoked. Formal investigations involving the SEM Committee and RAs have, however, been carried out with regard to the potential breach of the BCoP coinciding with significant levels of "constraining-on" of generators.

7.2.8 The RAs are of the view that the existence of market power alone, as detected by the HHI, PSI and RSI metrics, does not imply an abuse of market power. In fact the MMU has found that deviations from BCoP and SRMC bidding by those market participants that, based on traditional metrics such as HHI, PSI and RSI were deemed to have market power, have not occurred.

7.2.9 As also noted in the I-SEM Market Power Mitigation Discussion Paper[50], a high-level indication that the MMU and BCoP have been successful at restraining market power in the SEM is that the System Marginal Price (SMP) has closely tracked the gas price (National Balancing Point or NBP), a key generation cost input, as illustrated in Figure 7.1 below.

[50] Figure 5, SEM-15-031.

Figure 7.1: Evolution of SMP and gas price in SEM



7.2.10 Overall, the SEM Committee believes that the MMU has been effective at ensuring the market participants adhere to their licence obligations, in particular the requirements under the BCoP, with market pricing set at the appropriate Short-Run Marginal Cost (SRMC) level.

Directed Contracts

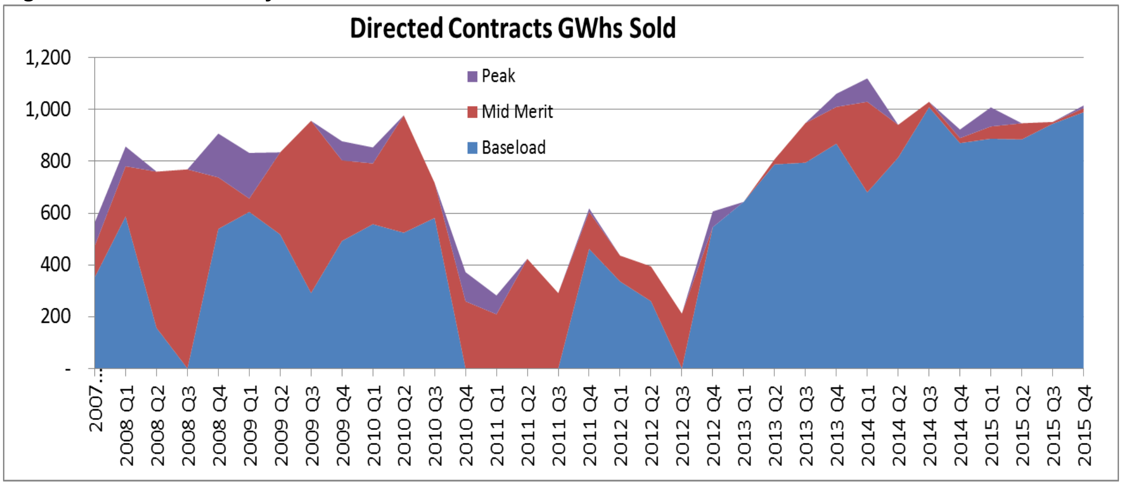
7.2.11 Directed Contracts (DCs) are mandated Contracts for Differences (CfDs) imposed on generators that are deemed to have market power. The two former incumbent generators, ESB and the Power NI Power Procurement Business (PPB), have to date been required to offer DCs in SEM based on forecasts of their spot market shares.

7.2.12 The volume and pricing is determined by the RAs with eligibility also set via an RA-approved methodology; thus DCs are offered at terms, which are beyond the control of the mitigated firms. The amount of generation that the mitigated firms have effectively available to offer in the spot market is the difference between the total generation owned and controlled less the volume of DCs. Thus DCs are considered to mitigate spot market power by reducing the incentive for the generators to submit bids into the BM above their SRMC, since such a strategy would not be profitable.

7.2.13 Initially, DCs were offered once a year for the following year. Since 2011, they have been offered according to "rolling quarterly approach", under which DCs are allocated on a rolling basis up to five quarters ahead. The intent behind adopting this approach was to allow the DC prices and quantities to be more up-to-date to market share and pricing forecasts, providing suppliers with more flexibility in hedging.

7.2.14 The volumes of DCs sold since the start of SEM are shown in the following graph. They were expected to decline because the firms offering them were predicted to lose market share. This was the case from 2009 to 2011. DC volumes increased again in 2013 when ESB PG and ESBI were allowed to horizontally integrate. The relatively low price of coal compared to gas during this period also contributed to a higher ESB spot market share – and therefore DC volumes – than might have been anticipated.

Figure 7.2: Evolution of DC volumes 2007-2015[51]



7.2.15 DCs are only a part of the CfDs available to suppliers in the forward market52. Other products include Non-Directed Contracts (NDCs), which are traded at prices and volumes determined by the generators and suppliers, not the RAs. However, to date it appears that only three firms have offered publicly-traded NDCs: ESB, PPB, and AES.

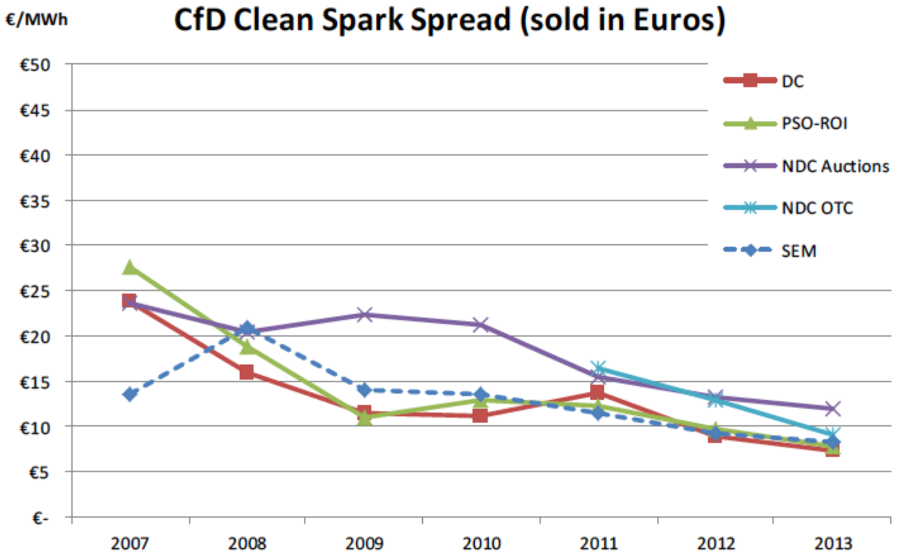
7.2.16 DCs have generally been priced at lower levels when compared to NDCs. This is most apparent when comparing CfDs (sold at different times) on the basis of clean spark spreads53, as illustrated in Figure 7.3 below.

[51] The Single Electricity Market: Market Update (October -December 2014), SEM-15-022, 9 April 2015

[52] DCs have represented up to about one quarter of total CfD volumes between 2007 and 2013.

[53] The clean spark spread is measured as the wholesale price of electricity minus the price of natural gas, and the cost of carbon credits, taking into account the fuel efficiency of natural gas in producing electricity. The clean spark spread is essentially the theoretical gross income of a gas-fired power plant from selling a unit of electricity (measured in MWh), having bought the fuel and carbon credits required to produce this unit of electricity.

Figure 7.3: CfD clean spark spreads 2007-2013[54]



7.2.17 Forward CfDs/hedges in the SEM have been offered by a limited number of firms, with ESB having a large market share. It is unclear whether this was the case because of the lack of interest by non-asset backed traders (i.e., there are better opportunities for them somewhere else) or due to some barriers to entry by potential players. Some market participants have noted that there is an up to 15% collateral requirement in the forward market, and that may act as a barrier to entry.. Even if the level of collateral were that which could be expected in a competitive market, credit risk arrangements may make it difficult for poorly capitalized players to enter the market. If, however, the collateral is commensurate with the trading partner's credit risk, it would be hard to argue that its level is a problem (at least from the point of economic efficiency), even though it would prevent the entry of some potential players.

7.2.18 Given the concentration of generation ownership, such potential for forward market power in the I-SEM may exist, but the RAs have not seen evidence to suggest that ESB or other participants have behaved (or will behave) in this manner. Overall, DCs appear to have reduced ESB's and PPB's (when applicable) incentive to exercise market power in the spot market, and therefore have been an effective measure to address concerns about structural market power in SEM.

Vertical ring-fencing

7.2.19 As a background, vertical ring-fencing on the former incumbent electricity companies of ESB in Ireland and Viridian in Northern Ireland is a legacy from the introduction of sector regulation and the separation of different costs components of these former public monopolies. In order to facilitate the

[54] Figure 21, SEM Contracting Report 2007-2013, SEM/14/073, 7 August 2014

effective introduction of competition into different parts of the cost chain, wholesale generation and retail supply, ring fencing of the vertically-integrated former incumbents (referred to as "incumbents" for ease of reading), was an important tool in the separation of costs and the prevention of cross subsidisation from one asset base to another. Where one business is regulated and another is facing competition, it is important that costs from competition are not incorporated into the regulated business and vice versa. When two or more business that are operating in competitive markets, there is not the same case for ring-fencing unless one or more of them possess market power.

7.2.20 The former is the case for vertical ring-fencing within the incumbent electricity company in Northern Ireland, Viridian, between their generation and supply business (Power NI is a regulated supply company). The latter is the case for the vertical ring-fencing within the incumbent electricity company in Ireland, ESB, which operates in a competitive generation wholesale and retail markets but possesses market power in the generation market.

7.2.21 Hence vertical ring-fencing of the incumbents is a SEM market power mitigation measure implemented with the purpose to mitigate potential market power arising from vertical integration, including where they have both generation and retail supply businesses. Vertical ring-fencing prevents these jointly-owned businesses from sharing information and working together between their retail and generation businesses. Any trades between them should thus be arms-length transactions, just like any other transaction they strike with other market participants.

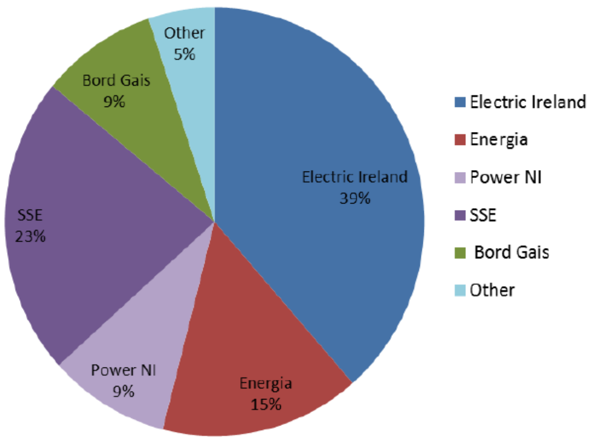
7.2.22 The RAs have assessed the effectiveness of vertical ring-fencing in SEM with respect to the theoretical harms and benefits. In such assessments, it is important to examine whether vertical ring-fencing is effective on its own, and in combination with other market power mitigation measures mitigates potential harm to competition.

7.2.23 Assessing the effectiveness of vertical ring-fencing on its own (i.e., as if no other market power mitigation measures were in place) is difficult, partly because it is not straightforward to estimate the impact of functional separation on generation and retail market performance, and partly because market outcomes that can be observed may have been influenced by other mitigation measures.

7.2.24 A previous RA review of the market power mitigation measures in SEM, which started in 2010 and concluded in February 2012 (see earlier in this section), found that vertical ring-fencing - specifically of ESB as this was under review around that time - should continue. The reasons for this at the time were that the wholesale market was quite highly concentrated and there was a concern over potential damage to competition if ESB were allowed to horizontally integrate. However, ESB's generation units/businesses were allowed to integrate as this was not considered to represent a significant market power risk; subsequent to licence change this was undertaken by ESB in 2013.

7.2.25 To assess the effectiveness of ring-fencing, the RAs have examined market developments since the last review. At that time, the retail market in the RoI was opening up and developing rapidly, with ESB rapidly losing market share, as shown in Figure 6.4 below. Even with these developments, it was recognised that access to liquidity was very important for potential retail market entrants, and allowing VI was seen as potentially harmful to such liquidity. These concerns were voiced by market participants who pointed out the lack of products offered in forward market, for example, products of a longer duration, for non-integrated retailers wishing to offer say a one year tariff.

Figure 7.4: Retail supplier market shares in SEM Sept'13-Aug'14



7.2.26 Although today in the retail markets Electric Ireland (ESB) is still a major player, as shown in Figure 6.4, its market share has stabilised in the recent years. Thus, it appears that while there has been significant new entry, and expansion of competition in both the domestic and commercial sectors, these competitors have not eroded ESB's retail market significantly. At the same time, other vertically integrated firms (SSE, Bord Gáis) have gained higher market shares. The evolution of these market shares is an important consideration for the market power mitigation strategy.

7.2.27 Some respondents to the I-SEM Market Power Mitigation Discussion Paper have questioned whether ring-fencing has effectively been implemented. They argued that these provisions should be more detailed than the current provisions and should look to require complete segregation of generation and supply businesses. On the other hand many stakeholders argued that ring-fencing should be retained, either because they believed it worked well or because of the high levels of continuing dominance.

7.2.28 The RAs have seen no direct evidence to suggest that there has been a breach of ring-fencing requirements. For example, the RAs have no evidence that ESB is offering NDCs to Electric Ireland cheaper than rival suppliers or is passing over commercially sensitive information. Overall, the vertical ring-fencing measures applied in SEM to ESB and Viridian seem to have served their purpose, in conjunction with the other mitigation measures applied.

7.3 ASSESSMENT OF CURRENT SEM MEASURES

7.3.1 In summary, the following is the SEM Committee's view with respect to the current market power mitigation measures in SEM. This forms a backdrop for the proposed I-SEM market power mitigation measures referred to in section 8.

- **MMU** - the MMU function has worked well in SEM, especially in monitoring and enforcing BCoP.
- **Bidding Code of Practice** - the current BCoP has been effectively enforced, and it has likely prevented market power abuses, especially where local market power arises due to system constraints, despite the fact the formal local market power mitigation measures have not been formulated.
- **Directed Contracts** - DCs have reduced ESB's and PPB's (when applicable) incentive to exercise market power in the spot market and have therefore been an effective measure to address concerns about structural market power.
- **Vertical ring-fencing of the incumbents** - the general view is that vertical ring-fencing of ESB and Viridian has been effective working alongside other market power mitigation measures.

7.4 CONSULTATION QUESTIONS

7.4.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

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

8 SEM MITIGATION STRATEGY AND MEASURES

8.1 INTRODUCTION

8.1.1 This section presents the SEM Committee's proposals and options for an I-SEM market power mitigation strategy covering I-SEM's relevant markets/trading periods (detailed in section 3). They are formed against the backdrop of the SEM Committee's view that the current SEM market power mitigation measures have been broadly effective, as discussed in section 7, as well as emerging developments which may be external to I-SEM itself but are of relevance to I-SEM market power. These issues are discussed in section 2 and include increased intermittent renewable generation, interconnection and demand-side management, along with REMIT (see also section 8.2).

8.1.2 The market power mitigation proposals and options are made in the context of the envisaged design of I-SEM and interaction issues as per section 4, the modelling results detailed in section 6 and the SCP approach to assessing market power explained in section 5. They are also framed by reference to the issues and principles referred to in sections 8.2 to 8.4 below.

8.2 BACKGROUND AND CONTEXT

8.2.1 This subsection provides a background to some the issues, discussed earlier in the paper, which are relevant to the I-SEM market power mitigation approaches and options as introduced here and detailed later in section 8.

8.2.2 Among other objectives discussed in section 1, the SEM Committee seeks to ensure that both competitors and end-use consumers are protected from the exercise of market power via measures that enable efficient and transparent price formation in I-SEM's physical and financial wholesale markets. Efficient prices in the physical markets are those that meet a competitive outcome such that they reflect the Short Run Marginal Cost (SRMC) of meeting the last (or next) MWh of demand, as referred to in section 4

8.2.3 The objective of SRMC based pricing in the physical markets is compatible with the commercial objective of efficient generation owners to recover both fixed and variable costs through market revenues. With SRMC based outcomes in the physical energy markets (DAM, IDM and BM), efficient generation plants which do not set the price can recover their fixed costs through a combination of inframarginal rents in the physical markets and through the Capacity Remuneration Mechanism (CRM).

8.2.4 As discussed in section 4, there is a distinction between high prices that are due to the exercise of market power and high prices due which are due to scarcity - which are necessary to signal the need to make additional generation available or to curtail demand. In general, the RAs consider that generators should not be allowed to include their own expectation of scarcity rents or future inframarginal rents in their offers because there is a concern of not being able to differentiate between the exercise of market power and genuine legitimate behaviour leading to high prices due to scarcity. These issues are best addressed by appropriate market design; for example, this could include administered scarcity pricing if introduced in the I-SEM, or market instruments that facilitate convergence between physical markets including virtual bidding where market participants may reflect expectations of forthcoming scarcity through submitting demand side bids into the near term markets.

8.2.5 Hence, and as referred to in section 4, the SEM Committee considers that the competitive outcome for the physical energy markets are prices that reflect overall SRMC and views prices that deviate from this benchmark as a potential indication of market power abuse. The SEM Committee's focus is on competitive outcomes and market power mitigation options with respect to the I-SEM physical markets rather than the forward financial market. This for the reasons discussed in section 4.3, including that the forward market is primarily a matter for EU financial regulations and regulators, rather than the RAs, though of course the RAs will co-operate with the financial regulatory authorities in this area to the appropriate extent.

8.2.6 Given the results of the modelling work reported in section 6, the SEM Committee considers that there are time periods when generation owners could have market power. This market power could manifest itself either through physical or financial withholding, i.e. either by not offering a generation plant into the market or by offering it with an offer price in excess of SRMC. Where a generator company has a portfolio of plants, such withholding could increase the price, increasing its profitability even if its generation output is reduced. This means that a competitive dynamic that would drive prices to SRMC would not arise on its own, and that intervention would be needed via regulatory market power mitigation measures to bring the market outcome closer to SRMC.

8.2.7 REMIT, as discussed in section 2, is a new EU-wide market rules and monitoring framework related to wholesale markets in electricity and gas. It is particularly relevant to I-SEM market power from a policy perspective as it prohibits market abuse on an ex-ante basis, provides for EU-wide market monitoring via ACER which the RAs can access, and facilitates enforcement by the RAs at national level. This enhanced market rules, monitoring and enforcement regime, which is both ex-ante and ex-post in nature, is accounted for by the SEM Committee in developing I-SEM market power mitigation proposals later in section 8.

8.2.8 In general the SEM Committee notes that there are a range of ex-post measures available to it to monitor the conduct and performance of the physical energy markets. These include the Market Monitoring activity of the

RAs, discussed in section 8.5, which monitors the conduct of market participants and the overall performance of the market. As referred to above, REMIT also gives the RAs the ability to assess transaction data in the SEM, and this ability will continue in the I-SEM. Where market manipulation is identified, the RAs can take action under REMIT and existing ex-post competition powers, in conjunction with other relevant agencies. The RAs will continue to rely on these measures under I-SEM, and these are discussed in more detail in Section 8.4.

8.2.9 Even with REMIT (which is both ex-ante and ex-post in nature) and other ex-post measures available under I-SEM, the SEM Committee considers that relying on these measures would not be sufficient to protect customers and competitors from the exercise of market power, given the level of structural market power forecast for I-SEM. Hence the SEM Committee has concluded that some level of ex-ante mitigation measures (as well as ex-post) will be required to assist the competitive dynamic to a level that will lead to outcomes close or equal to SRMC. Various ex-ante measures are referenced at a high level below and then detailed later in section 8. These measures address both the incentive and the ability to manipulate the markets, using the Structure-Conduct-Performance (SCP) paradigm referred to in section 5.

8.2.10 Firstly, contracting forward for the sale of a certain volume of generation removes the incentive to increase prices above SRMC levels for that volume. The existing Directed Contracts approach fit this purpose in a targeted fashion as discussed in section 7, and the SEM Committee considers that a similar incentive based ex-ante mitigation measure is warranted in I-SEM, though its form and reach could be different. The structure of such a forward contracting obligation is discussed in Section 8.6.

8.2.11 The SEM Committee further considers that mitigation measures that restrict the “ability” to exercise market power may also be required to ensure a competitive outcome in the various physical energy markets. The SEM Committee recognises that the competitive dynamic differs across time periods and has proposed different mitigation measures accordingly. Based on the modelling in section 6 which highlighted that generation plants may be especially pivotal in the Balancing Market (BM) due to its short-term nature, and due to local market power concerns in the BM (see section 4), the SEM Committee has concluded that a market power mitigation intervention is needed in this timeframe. Since the BM is mandatory, there is no need for any mitigation measure to address physical withholding of generation output; hence the policy is designed to address financial withholding, i.e. generators submitting offers above SRMC. The proposed options related to the mitigation of market power in the BM are outlined in section 8.7.

8.2.12 Next the SEM Committee addresses the issue of any necessary mitigation measures in the DAM and IDM. In light of other planned mitigation measures, namely a forward contracting obligation, and planned mitigation measures in the BM, the SEM Committee is assessing whether specific mitigation measures are needed in the DAM and IDM. While the ability of demand to move from the DAM and IDM, if prices rose above SRMC, to the BM (where active mitigation measures are planned as above), would argue against the need for further mitigation measures, the SEM Committee currently has some doubt as to whether this would materialise.

8.2.13 Firstly, discouraging demand participation in the DAM and IDM makes the role of the TSO in operating the BM more difficult. Secondly, suppliers may be willing to pay a higher price in the DAM and IDM as a way to manage risk associated with uncertain BM prices. In addition, the modelling results in section 6 indicate a level of structural market power out to 2024. The SEM Committee is therefore concerned that generators may be able to extract this risk premium from suppliers through offering above SRMC.

8.2.14 Since the DAM and IDM are voluntary, it is not possible to conclude that any generator not participating in these markets, by not submitting an offer, is physically withholding from a market power point of view. A generator not making an offer in either of these markets may have concluded that better opportunities lay in the BM. Hence any mitigation measures applicable to the DAM and IDM would be limited to addressing issues of financial withholding. The possible approaches to mitigation measures applicable in these timeframes are discussed in Section 8.9.

8.2.15 The SEM Committee has also reviewed the existing vertical ring-fencing measure that has the outcome of limiting the ability of the former incumbents (which have both generation and supply activities) to exercise market power in other aspects of the market, such as the retail market or the forward contracting market. Section 8.11 discusses this policy measure in the context of I-SEM.

8.3 KEY PRINCIPLES FOR MARKET POWER MITIGATION MEASURES

8.3.1 The SEM Committee seeks to ensure that both competitors and end-use consumers are protected from the exercise of market power via measures that among other objectives discussed in section 1, enable efficient and transparent price formation in I-SEM's physical and financial markets. The SEM Committee considers the following five key principles to be appropriate as the basis for assessing various market power mitigation policies as discussed later:

- **Effective**: the proposed measure is effective in mitigating the potential market power conduct (behaviour) or outcome (market performance), and is consistent with the objectives detailed in section 1 of this paper.

- **Targeted**: The objective is to interfere with the operation of the market to the minimum extent necessary. A targeted policy can be considered on two dimensions: to minimise the number of participants to which it applies, and to minimise the number of situations (markets, timeframes) or behaviours to which it applies. A targeted policy should also limit the impact on the commercial incentives of market participants and it allows for innovative bidding strategies. Market power mitigation measures should allow a reasonable return on new investments in order to encourage competition to emerge and to signal the need for investment.

- **Flexible**: The mitigation measures should be sufficiently flexible, and robust, to account for changes in market fundamentals, such as swapping of the merit order of fuel types, changes in congestion patterns due to new transmission capacity, and changes in the generation mix due to new additions and closures of existing generators. Flexible also implies the ability to easily sunset a market power mitigation measure if conditions warrant its removal and, if feasible, the conditions under which such a scheme could be removed should be stated in advance.

- **Practical**: Market power mitigation should allow the RAs to have readily understood, predictable and reasonable administrative processes to implement the mitigation measures and facilitate enforcement within a short timeframe. A market power mitigation scheme should be cost-effective and not excessively difficult to implement and within the scope of the regulatory framework of the SEM Committee and the RAs.

- **Transparent:** Market power mitigation measures should be easily understood and compliance should be easily achievable and transparent for all existing and potential participants to view.

8.3.2 As the RAs have recognised, there may be some conflict among these principles. For example, effective mitigation may require complex strategies. Similarly, publishing some market power detection techniques may render them ineffective if the market participants can in response alter their behaviour, and thus avoid detection.

8.3.3 In addition, the proposals and options for market power mitigation in this section can potentially result in two types of error:

- **“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.

8.3.4 The SEM Committee strategy focuses on mitigation measures that either incentivise competitive behaviour or, where considered necessary, mitigate generator offers to competitive levels, such that the physical market outcomes are competitive. The SEM Committee uses SRMC offers and prices (i.e. market outcomes), which includes administered scarcity pricing if introduced, as a key competitive benchmark. This is explained in section 8.2 above and in section 4 of the paper. This benchmark applies for all proposals and options referred to later in this section.

8.3.5 The SEM Committee believes that it is possible to define and monitor competitive behaviour in a manner that minimises costs associated with a Type 1 error. Type 2 error is a failure to mitigate market power abuses which leads to market prices above or below the competitive level, with potentially very large costs to consumers, and to competitors. Therefore the SEM Committee is seeking measures to incorporate into the strategy that keep the risk of Type 2 error at a minimum, while also being mindful of the costs of Type 1 errors.

8.3.6 Given the issues referred to in section 8.2 and elsewhere, there are risks for consumers associated with relying entirely on ex-post powers, namely that the exercise of market power, leading to higher prices, has already taken place before the impact is known and remedies implemented. Hence the ex-post regime that is likely to apply by I-SEM go-live, including REMIT, and the desire to prevent a Type 2 market power error in particular, points to the need for some additional and limited ex-ante regulatory intervention as part of an overall I-SEM market power mitigation strategy. In sections 8.4 and 8.5 below the RAs discuss the ex-post regime with respect to I-SEM market power before then introducing ex-ante proposals/options.

8.4 I-SEM ENFORCEMENT MECHANISMS

8.4.1 As introduced in section 8.2, the SEM Committee has today a range of ex-post monitoring and enforcement capabilities, and intends to continue to use these once I-SEM goes live. Ideally, the SEM Committee and the RAs would, to the maximum extent practical, rely more on ex-post rather than ex-ante powers in mitigating I-SEM market power, consistent with one of our five guiding principles, i.e. of having targeted intervention. The extent to which RAs can rely on existing monitoring and enforcement mechanisms to ensure competitive outcomes has implications for the optimal mix of market power mitigation policies.

8.4.2 In the current SEM the RAs actively monitor the conduct and performance of the market. In the event that any market manipulation is identified, the RAs can take enforcement action.

8.4.3 In Ireland, the CER may pursue generation licence breaches (e.g. of BCoP) via directions/orders from the courts. For example, the CER is entitled to give a direction to the licence holder to take any measures necessary to cease the contravention or to prevent a future contravention. To ensure compliance with a direction, the CER may apply to the High Court for an order to refrain from specified practices. The High Court may make such order as it thinks fit and may confirm, revoke or vary a direction given by CER. It is expected that CER's ex-post enforcement powers will be enhanced by I-SEM go-live in areas of relevance to market power mitigation. Specifically, the CER may be able to impose a major sanction to a party with respect to a licence breach, albeit only with the involvement of the Courts and possibly an Appeals Panel.

8.4.4 In Northern Ireland, the Utility Regulator currently has more extensive ex-post powers of relevance to market power mitigation than the CER. If the Utility Regulator finds a market participant in breach of its licence conditions, it may:

- Issue an enforcement order to ensure compliance with licence conditions;
- Impose financial penalties (what is reasonable in the circumstances);
- Revoke a licence.

8.4.5 The Utility Regulator also has powers relating to the enforcement of competition under the Competition Act in relation to commercial activities connected with the generation, transmission, distribution or supply of electricity. In these areas the Utility Regulator is entitled to exercise concurrent powers with the Competition and Markets Authority.

8.4.6 The introduction of REMIT and the recent go-live of the transaction data monitoring system in ACER (which the RAs may access) has given further powers and abilities to the RAs in relation to market power mitigation. Pursuant to REMIT (see sections 2 and 8.2), the CER has ex-post powers to prosecute market participants that engage in market manipulation or insider trading. Pursuant to S.I. No. 480 of 2014 the fines for such a breach on summary conviction in Ireland is up to €5,000 and on conviction on indictment to a fine for a body corporate not exceeding €500,000.

8.4.7 The Utility Regulator also has powers to impose similar ex-post sanctions/penalties under REMIT if it finds that a market participant failed to comply with a REMIT requirement. The determination of the amount of the penalty, must have regard to: (1) the seriousness of the failure in question in relation to the nature of the requirement not complied with; (2) the behaviour of the person; and (3) whether the person on whom the penalty is to be imposed is an individual.

8.5 RA MARKET MONITORING

8.5.1 The modelling results show that there will continue to be a level of aggregate structural market power in I-SEM to 2024, while there will also be ability for participants to exercise market power for other reasons, for example due to local transmission system constraints or due to technical operating constraints. Furthermore, international experience suggests that there is a continued need for proactive market monitoring even as electricity markets become more competitive. The basis for any ex-post enforcement action is active monitoring and investigation of the conduct of market participants and the overall performance of the market.

8.5.2 In light of this, the SEM Committee considers that, for the foreseeable future at least, there will be a need for robust Market Monitoring activity by the RAs, as a strong ex-post market power mitigation measure in I-SEM. To facilitate this, the NEMO for DA and ID markets and market operator for the BM and imbalance settlement will be required to provide timely market data to the RAs for analysis. This will be in addition to any surveillance of the relevant markets that they will carry out themselves. The RAs will also be able to access data collected by ACER as part of its EU-wide wholesale market monitoring under the auspices of REMIT.

Roles and Responsibilities

8.5.3 In carrying out their market monitoring and enforcement activities, the RAs will:

- Determine what constitutes competitive in the I-SEM physical trading periods, i.e. to the extent that that they are consistent with SRMC pricing/outcomes as discussed in sections 4 and 8.2, including what are the other appropriate metrics and benchmarks to use such as mark-up indices, withholding analyses and net revenue metrics - see section 5 of the paper;

- Monitor the conduct of market participants and the overall performance of the market in the various I-SEM physical trading periods, including compliance with any market power mitigation measures. It will involve itself in monitoring the forward financial trading period only to the extent appropriate, taking account of the financial regulatory regime and its role in this market. It would involve developing and using the appropriate metrics and benchmarks referred to above. It would also include monitoring and analysing the overall financial performance of market participants, using public and regulated financial accounts, and carrying out financial/technical audits and spot checks on market participants; and,

- Monitoring and verifying compliance with REMIT, which prohibits wholesale market manipulation and insider trading on an ex-ante basis such that the RAs could take enforcement action for non-compliance (as discussed earlier in section 8). This would include being able to access data collected by ACER as part of its EU-wide wholesale market monitoring.

8.6 FORWARD CONTRACTING OBLIGATION

8.6.1 Market participants who contract prior to the day-ahead market timeframe lack an incentive to exploit market power in the I-SEM physical markets, for the volumes that are contracted. A forward contract obligation (FCO) is an ex-ante market power mitigation measure proposed by the SEM Committee with respect to the I-SEM physical market, given that, among other issues, the modelling results indicate that there is likely to be at least one participant with a level of market power to 2024 - see section 6.

8.6.2 This approach would require a market participant deemed to have market power in the physical market (in one or more of the trading periods) to contract before the day-ahead market. It would form another ex-ante market power mitigation measure with respect to the physical market. The form this measure would take, its applicability, etc. is for consideration as discussed below.

8.6.3 Section 7 discussed the effectiveness of the SEM forward contract obligations, Directed Contracts (DCs), which applied to the incumbent generators at the beginning of the market, ESB and PPB. When designing such measures for I-SEM, a number of issues need to be considered by the SEM Committee as follows,

1. What is the measure and threshold that results in a market participant being included or excluded in the FCO, i.e. what is its applicability?
2. What is the volume and product definition of forward contracting required from a market participant who falls under the FCO?
3. How is the price set for the volume contracted under the FCO?
4. What type of access do buyers have to FCO volumes?

8.6.4 Each of these issues is discussed in more detail below and the RAs would welcome feedback on them. Taking into account stakeholder comments, the RAs will carry out a full review of options for the FCO against the five key principles for this workstream (in section 8.3).

Applicability

8.6.5 The first question on FCO applicability requires the selection of a measure and threshold for the application of the FCO on a market participant. As previously discussed there are a number of metrics that can be used to determine market power including market share, RSI and HHI. The threshold for setting the application of the FCO would be unique to the chosen measure. For example with forecast market share the threshold could be

25%, with the RSI it could be a participant with a forecast RSI below 1.2 for 5% or above of time across the year, and for the HHI it could be a threshold of 625 for an individual participant. These examples are not an indication of the RAs preferred thresholds, rather an illustration of the mechanism.

8.6.6 In SEM the FCO/DCs have been applied solely to the former incumbent generators, where one (ESB) has remained the largest generator in the market and the other (PPB) has become one of the smaller generators in the market, due to the cancellation of power purchase agreements with other generators. DCs do not currently apply to generators other than the incumbents, regardless of their market share.

8.6.7 A potentially more targeted and flexible approach, which correspond to the regulatory principles referred to in section 8.3, would take account of the changes in the market via a wider FCO requirement (not only applying to the incumbent generators), whether these are driven by and could vary with market entry, exit, mergers or divestment – see the modelling results in section 6 as an example.

Volume and Product

8.6.8 The second question is to address what is the appropriate volume and product definition that a participant with an FCO should be required to offer. In order to remove the incentive from a market participant deemed to possess market power from exercising it, a significant portion of its forecast capacity would need to be sold before the physical markets in I-SEM. This is because when a participant sells a portion of their capacity forward, it becomes indifferent to the price they receive in the physical spot markets for this capacity but still may have an incentive to exercise market power for any remaining capacity unsold in the forward market. In this situation a participant would have an incentive to use all their generation capacity to exercise market power in the physical markets, even the capacity that was sold forward, as they are only indifferent to the price changes for that volume.

8.6.9 A range of product definitions can be used to shape of the forecast volume on offer to the forecast profile of generation. This includes both the duration of the contract i.e. annual, quarterly, monthly, weekly etc. and the hours of the day that the contract applies to i.e. baseload, mid merit etc. The range of contracts on offer can impact on the overall liquidity in the forward market, subject to the volume of secondary trading taking place.

8.6.10 In the SEM the volume of DCs is set by ongoing forecast modelling by the RAs that seeks to reduce the HHI of the spot market to 1,150 and results in ESB offering forward contracts to achieve this result. There are three DC products offered, baseload, mid-merit and peak. The modelling results suggest that the total volume of contracts that ESB can offer into the future will decline, driven by the increasing share of wind in the market.

Price Setting

8.6.11 The third question asks what is the most suitable method for setting the price of FCO volumes offered by a participant. This could be left to the participant themselves, with the sole obligation to sell a forecast volume of FCOs; it could be set by the RAs or there could be a combination of the two. This could include the setting of reserve prices by the participant/RAs, the inclusion of a regulated bid/ask spread or the setting of the price by the RAs.

8.6.12 In the SEM the DCs are set administratively by the RAs, while for some other contracts such as the Irish PSO-related contracts, the CER sets the reserve price and allows the market to bid up the price in an auction. This approach may be seen as more targeted and transparent, again principles for this workstream, though they may be less effective in mitigating market power.

Buyer Access

8.6.13 The final question looks at the access that buyers of FCO volume have. This can be market-based or administered by the RAs. A market-based approach would allow the highest bidders to obtain the preferential access to FCO volume. In the SEM the DCs are administered, with access only allowed to suppliers with customers in the retail markets of Ireland and Northern Ireland and is based on their current market share. This approach may limit competitive entry and exit in the forward market as a retail supplier needs to demonstrate a certain level of market share before they are able to receive an allocation of DCs.

8.7 BALANCING MARKET BID MITIGATION

8.7.1 As discussed in section 8.2, and reflecting the modelling of the short-term energy actions in the balancing market (BM) in section 6, there may not be a sufficiently competitive dynamic in the BM to drive offers to the level of SRMC. In addition the constrained nature of the all-island power system means that any generator may possess local market power in the BM for non-energy actions at some point, i.e. submit offers which are different to SRMC, even if it does not have overall structural market power, as discussed in sections 4 and 8.2.

8.7.2 Given these concerns, the SEM Committee proposes implementing an explicit ex-ante bid mitigation measure for the BM. A single mitigation measure may be used to target market power for both energy and non-energy actions.

8.7.3 There are 3 bid mitigation options in the BM proposed for consideration, as detailed later in this section. In summary, they are:

- Option 1: RA/MMU Triggered Intervention, which is focused on preventing local market power being exercised by replacing bids as needs be with formulaic/prescriptive SRMC bids, manually and ex-post via the MMU/RAs.
- Option 2: Automated Intervention, which has the same intention as Option 1, but instead is applied automatically and ex-ante. There are two sub-options provided, with Option 2a involving particular software and a PST test, and Option 2b involving the "flagging and tagging" process;
- Option 3: Prescriptive Bidding Controls, which is broader and involves prescriptive bidding controls such that generator bids are set mandatorily ex-ante at formulaic SRMC levels for all trades in the BM. This would be with the aim of mitigating short-term market power for both energy and non-energy-actions in the BM.

8.7.4 For each of these options, the RAs would calculate the SRMC cost curve formula for each generator and keep on file the method used by each generator to set key elements of the marginal cost, including fuel, variable O&M, start-up costs, the heat curve and physical constraints such as start-up times. This would then be applied to replace bids as needs be for Options 1 and 2, and used for monitoring compliance with the mandatory formulae in Option 3. For both sub-options under option 2 the generators could be required to submit two offer curves (which could be the same), one being developed by them and one being the SRMC cost curve, with the latter applied by the TSO if option 2's criteria are met.

8.7.5 It should be noted that for all options, the SRMC formulae still allow generators to innovate to a certain extent, in driving down costs as specific cost levels would not be prescribed. Generators could also vary prices in response to different hourly fuel prices or to different operating procedures, for example coal handling.

8.7.6 The options are discussed in more detail next, followed by an initial comparison of their relative merits and drawbacks.

Option 1: MMU-Triggered Intervention

8.7.7 Option 1 involves the RAs monitoring generator offers to identify generator offers in excess of SRMC that would be consistent with the exercise of local market power by a market participant and then, if observed, directing the TSO to replace its offers with an explicit SRMC-based offer curve (verified by the MMU) for a set number of future settlement periods thereafter. By definition this intervention would occur after the market has cleared, and would apply only to future time periods[55]. In terms of practicalities, the RAs could possibly require the TSO to reject any offer thereafter from the participant that does not comply with this SRMC standard, and instead apply an explicit SRMC offer curve already pre-approved by the RAs.

8.7.8 This approach would apply not only to local market power issues but also energy balancing actions in the BM, as it will by definition apply to both energy and non-energy actions, as the same bids are used by the TSO.

Option 2: Automated Intervention

8.7.9 This option can be split in two sub-options, which are explained in more detail in the following paragraphs. Option 2a would rely on the TSO performing a Pivotal Supplier Test (PST) to identify what bids should be replaced by a regulated SRMC-based offer curve. Option 2b would rely on the "flagging and tagging" process to identify constrained balancing actions, which in turn would have the original prices submitted by generators replaced by a regulated SRMC-based offer curve.

8.7.10 Option 2a is a fully automated and structural ex-ante mitigation mechanism employed by the TSO that uses a dynamic definition of a relevant local market. It identifies a potential exercise of market power via structural metrics such as a PST and then automatically switches the participant's offers to SRMC using a prescriptive offer curve, in advance of the market clearing in the BM. A similar approach applies in other markets such as in PJM. For clarity, with this approach, "manual" RA intervention as per Option 1 could still be applied for intervention if there was market power exercised without the automatic trigger – but here we will focus on the automatic aspect.

8.7.11 This bid mitigation approach for local market power is dynamic and reflects the fact that local markets change with transmission constraints. Specifically, the TSOs would: (1) determine the relevant local market in each period[56]; (2) determine the available local supply; (3) apply a structural market power test, e.g., PST; and, (4) reset the generator offers of those generators that fail the test to an explicit SRMC offer curve. Further information on this approach is provided in Appendix E.

8.7.12 In general, local market power in I-SEM is most likely to arise due to thermal and voltage constraints, and therefore Option 2a would primarily apply to them. The majority of these constraints are currently must-run constraints,

[55] Enforcement for un-competitive behaviour that led to the imposition of the ex-ante bidding controls would also be carried out by the RAs.

[56] This generally requires the TSO to operate security-constrained economic dispatch and monitor dynamic transmission constraints in real time.

for example a certain number of units must be online at their minimum generation level in a given area if demand exceeds a threshold. The ownership of the units that are eligible to satisfy these constraints is sufficiently concentrated that a 3 PST would be failed most of the time, such that bid mitigation would apply much of the time.

8.7.13 Option 2b would involve the use of regulated SRMC offers to all balancing actions which are related to system constraints. During the process of calculating the imbalance price, the TSO would identify energy and non-energy actions via a “flagging and tagging” procedure. The TSOs would only replace the unregulated offer by a regulated SRMC-based one if a generator was called to address a local system constraint.

8.7.14 In summary, the difference between the options is that in Option 2b the TSO would not use PST metrics and associated software to identify local market power such that an SRMC offer curve would be applied if the PST is failed. Instead, all non-energy actions of the TSO would be treated as a potential instance of local market power and thus have an SRMC offer curve applied.

Option 3: Prescriptive Bidding Controls

8.7.15 Option 3 involves prescriptive ex-ante bidding controls where all generator bids are set mandatorily at formulaic SRMC levels for all trades in the BM (not only with the aim of mitigating local market power). Under this option, SRMC-based offers would be maintained as the default for the BM. The MMU would verify the SRMC-based offers on an ex-post basis and require bids to be changed to comply if needs be.

8.7.16 This option is broader than the first two options and its aim would be not only be to mitigate local market power but also short-term market power in the BM for energy-actions which can arise from there being a limited number of generation plants available to meet system demand. As exemplified in the modelling results in section 6, this need can lead to increased structural market power in the BM compared with the DA and ID markets, and therefore may justify a market power mitigation measure to cover all trades in the BM.

8.8 INITIAL ASSESSMENT OF BID MITIGATION OPTIONS

8.8.1 This section provides an initial RA assessment of the options for bid mitigation in the BM against the five key principles referred to in section 8.3. Taking on board stakeholder consultation responses, the RAs will further analyse these options against the principles before coming to a decision on the matter.

Effective

8.8.2 Options 2 and especially 3 are arguably more effective in mitigating market power than Option 1. This is because both of the sub-options in Options 2 apply ex-ante to non-energy actions irrespective of generator behaviour (with Option 2a only applying if a PST is failed), while Option 3 applies ex-ante to all offers in the BM. In contrast Option 1 involves RA/MMU intervention after a market power breach has occurred (rather than ex-ante), with SRMC offers then applied for a period thereafter.

Targeted

8.8.3 Option 1 is capable of being targeted in that the RAs can determine which offers represented the harmful exercise of local market power and then make the appropriate intervention for future trading periods. Option 2 is less targeted than Option 1 and operates irrespective of generator behaviour, with Option 2a operating only if a PST is breached in a constrained local area and Option 2b applicable to all offers in a constrained local area. Option 3 is arguably the least targeted of the options as it deliberately applies to all offers in the BM, irrespective of whether they are energy or non-energy related.

Flexible

8.8.4 Option 1 allows flexibility in intervention based on an evaluation by the MMU of the nature and impact of the exercise of market power. Option 2b is also flexible as it doesn't need specific additional systems to implement and hence can be applied (or not) relatively easily. Option 2a is arguably less flexible as it needs systems to implement, so there could be a sunk cost if it were desired to remove the measure at a later date. ur Option 3 is also arguably less flexible as it deliberately applies to all offers in the BM and so there is no obvious "sun-setting" aspect to it.

Practical

8.8.5 Option 1 would require a well-resourced MMU to manually detect uncompetitive bidding instances. Option 2a may be complex from a TSO systems point of view, and the systems/software may be costly to implement and not available for I-SEM go-live. Option 2b should be relatively straightforward to implement as it would rely on the flagging and tagging process that the TSO would have to develop for imbalance pricing57. Thus Option 2b could score highly against this principle. Option 3 would likely involve less ongoing intervention by the TSOs/RAs than the other options (which could be seen as advantageous), though RA/MMU monitoring for compliance would still be needed.

[57] Please see SEM-15-065

Transparent

8.8.6 Transparency of operation in Option 1 would be dependent on the publication of the operations of the MMU including criteria for intervention. Option 2a would be relatively transparent if the exact PST for a local area were defined beforehand. In option 2b transparency would also require clarity on the identification of offers related to system constraints only. Option 3 would be transparent where the formulaic SRMC levels would be known and applied by the generators themselves.

8.9 MITIGATION MEASURES FOR DA AND ID MARKETS

8.9.1 As outlined in section 8.2, the SEM Committee remains concerned that the existence of structural market power will not give rise to a sufficiently competitive market dynamic in the DAM and IDM. This is related to the modelling results in section 6 which indicates a level of structural market power, and issues such as demand potentially willing to pay a higher price in the DAM and IDM rather than managing risk with more uncertain BM prices.

8.9.2 However the SEM Committee is also cognisant that the intervention on the DA and ID market should carefully considered as these markets have greater potential for competitive outcomes.

8.9.3 In addition to applying some form of bid mitigation in the BM, ranging from local market power mitigation to prescriptive ex-ante bidding controls (as discussed above), the SEM Committee has considered various bidding regime options for the DA and ID markets, including:

- **Option 1: Prescriptive Bidding Controls**, requiring all generators bids to be set mandatorily at formulaic SRMC levels;

- **Option 2: Bidding Principles and Ex-Post Enforcement.** These principles consist of ex-ante guidelines that require generator bids in the DA and ID markets to generally be at SRMC, but not necessarily in every trading period, with the MMU reviewing bids for the exercise of market power using various metrics including an SRMC benchmark;

- **Option 3: Ex-Post Enforcement Only,** i.e. no explicit bidding regime (controls or principles) set ex-ante for generators in the DA and ID markets, but with the MMU reviewing bids for the exercise of market power using various metrics including an SRMC benchmark.

- **Option 4: Market Abuse Condition:** Market Participants would have a license requirement preventing market abuse. No specific bidding regime would apply in these markets. Market Participants deemed to have structural market power would have additional reporting requirements to the MMU.

8.9.4 With all approaches the MMU would monitor and review participant behaviour and market outcomes as described earlier. Also, for all approaches there will be monitoring of trades by the RAs and ACER for compliance with REMIT's ex-ante market rules (see sections 2 and 8.2), to assist the RAs in the detection of market manipulation and insider trading, with the RAs taking ex-post enforcement action to ensure compliance with REMIT's market rules as necessary. The final approach adopted by the SEM Committee for the DA and ID markets will be considered in a manner such that it complements - though could well be different from - the approach decided upon for the BM[58]. The 3 options are discussed in more detail below.

Option 1: Prescriptive Bidding Controls

8.9.5 With prescriptive bidding controls, deviations by generators from mandatory SRMC bid formulae is considered to be a violation of bidding rules. Such an approach could be desirable where there is a very significant level of market power, as is the case with respect to local system constraints and possibly for energy actions in the BM given the short-term market power that could be exercised in this market (see earlier).

8.9.6 However, for markets/trading periods where there is expected to be more competition and less market power, a prescriptive approach would not be justified. This is the case with the I-SEM DA and ID markets, which will be subject to cross-border trade and for which the modelling results in section 6 show a generally declining level of structural market power potential to 2024. Hence bidding controls in the DA and ID markets would not be in line with the I-SEM High Level Design because the overall objective of the design was to allow the market to operate to the maximum extent possible. Such strict bidding controls have the drawback of discouraging an innovative competitive strategy by market participants, one of the regulatory principles for this workstream, and it would be difficult to justify in light of reducing structural market power to 2024 as shown in the modelling in section 6.

8.9.7 Prescriptive bidding controls in the DA and ID markets would also be less practical, another regulatory principle in this area. They would be difficult to implement in practice where a bid would need to reflect a number of different operational conditions and where values may change frequently. This is potentially a problem for bids in the DAM, where the structure of the bids into Euphemia requires the generators to estimate a likely running

[58] Purely as an illustrative example and strictly without any indication as to the SEM Committee's decision at a later date, if bidding principles were adopted in the DA/ID markets, and prescriptive bidding controls were not adopted in the BM, then bidding principles could be applied for energy actions in the BM also.

pattern over the following 24 hour period. In practice, a single SRMC prescriptive bid formula is likely to be insufficient to describe the cost characteristics of every generator under all possible market and operational conditions. As a result, frequent deviations from the prescribed SRMC values could happen, reducing the ability of the RAs to enforce such bidding controls.

8.9.8 In light of these considerations, the SEM Committee does not believe it appropriate to implement the option of prescriptive bidding controls in the DA and ID markets in I-SEM, at least not generally (i.e. untargeted), though there may be specific circumstances where it is warranted.

8.9.9 A key issue which the SEM Committee is considering, however, is whether there should or should not be bidding principles, as discussed next in Options 2 and 3 respectively. This is followed by an initial discussion on the relative merits and drawbacks of each approach.

Option 2: Bidding Principles and Ex-Post Assessment

8.9.10 Bidding principles require on an ex-ante basis generators to bid SRMC costs in general, but they are looser than prescriptive bidding controls. They allow deviations from SRMC in certain trading periods so long as it delivers SRMC over a longer time period, and they allow generators to innovate with respect to their bidding strategies and to determine their SRMC within certain bounds.

8.9.11 The modelling results in section 6 show that, while market power in I-SEM physical markets is predicted to decline overall to 2024 as measured by the HHI, they would still be fairly concentrated - and with average RSI in fact decreasing to 2024. This could indicate the need to apply ex-ante principles to all generators, i.e. in an untargeted fashion. Bidding principles could be applied for the DA and ID markets only or they could be applied in all I-SEM physical markets including the BM (depending on the approach decided upon for the BM). As referred to earlier in this section, REMIT's ex-ante market rules would also apply, with monitoring of trades by ACER and the RAs as well as ex-post enforcement by the RAs. This could be in a manner which compliments bidding principles.

8.9.12 In addition, the DA and ID markets in GB are considered to be competitive and hence should drive offers and outcomes there that are consistent with the marginal cost of generation or dispatchable demand. This would provide for a level of consistency with I-SEM bidding principles.

8.9.13 Situations where the bidding principles would allow for deviation from SRMC in any trading period typically related to unit commitment issues. For example, an inflexible generator may offer below its apparent SRMC in some hours in order to avoid being out of merit and shut down during low-load hours. In fact, these situations could still be consistent with SRMC bidding if the offer reflects the fact that the generator were shut down, it would forgo the opportunity to generate in future hours when it could earn significant inframarginal rents that would off-set any loss incurred in the off-peak period. The level of flexibility allowed and enshrined in the bidding principles would need to be considered, and the RAs would welcome feedback on this matter.

8.9.14 The MMU would monitor compliance of generators with the bidding principles and REMIT, as well as market prices/outcomes/performance, i.e. using the Conduct and Performance aspects of the SCP paradigm discussed in section 5. The MMU would use a variety of metrics to do so, from the SRMC benchmark through to other indices such as mark-up indices, withholding analyses and net revenue metrics - see section 5 for the Conduct and Performance metrics that can be used.

8.9.15 Market participants would need to demonstrate to the MMU ex-post that they have complied with the bidding principles, the various metrics employed by the MMU (as above) and REMIT; indeed the emphasis in this regard would rest more with the market participants taking steps to demonstrate compliance with the principles rather than the MMU prescribing how the market participant could meet an SRMC benchmark. Based on this the RAs can take ex-post action, ranging from investigation through to enforcement, as considered appropriate.

Option 3: Ex-Post Assessment Only

8.9.16 Alternately there could be no ex-ante bidding principles regime specifically set by the SEM Committee for the DA and ID markets. Thus, in addition to monitoring compliance with REMIT's ex-ante rules (see next), the MMU would focus on the ex-post conduct of market participants and on the market pricing/outcomes/performance, i.e. using the Conduct and Performance aspects of the SCP paradigm discussed in section 5. It would use a variety of metrics to do so, from the SRMC benchmark through to other indices such as mark-up indices, withholding analyses and net revenue metrics - see section 5 for the Conduct and Performance metrics that can be used.

8.9.17 It should be noted that under this approach REMIT would continue to apply as referred to earlier, in terms of its ex-ante market rules, monitoring of trades by ACER and the RAs as well as ex-post enforcement by the RAs. Thus REMIT could also be complimentary to an ex-post only enforcement approach in as much as it is to an approach which includes bidding principles. In addition, the RAs will also identify additional data that the NEMO and TSOs will provide to facilitate this ex-post assessment.

8.9.18 This approach would also be similar to the one with ex-ante bidding principles in that market participants would need to demonstrate to the MMU ex-post that they have complied with the various metrics employed by the MMU (as above), as well as REMIT. Based on this the RAs can take ex-post action, ranging from investigation through to enforcement, as considered appropriate. Overall the key difference between Option 2 and Option 3 is that Option 3 does not have ex-ante bidding principles set by the SEM Committee against which participants must comply; otherwise the two options are essentially the same.

Option 4: Market Abuse Condition

8.9.19 Options 1, 2 and 3 present a decreasing level of intervention of the RAs in the DA and ID markets. Option 4 is at one end of the spectrum of possible regulatory controls as it is the option with the least amount of interventions. The SEM Committee is of the view that when compared to the Balancing Market, the Day Ahead and Intra Day Markets have relatively reduced vulnerability to the abuse of market prices. Therefore the SEM Committee sees merit in putting forward an option where the RAs intervention in these markets is less intrusive.

8.9.20 The key economic principle underpinning the development of market power mitigation measures is that efficient markets should drive prices towards SRMC. In the context of options 1 to 3, If individual orders to the day ahead and intra-day markets are different from SRMC (with some flexibility in terms of horizon and reason) then a market abuse event may be in evidence. Option 4 differs from options 1 to 3 to the extent that it aims at addressing the obstacles to efficient price formation instead of imposing a metric (i.e. SRMC either ex-ante or ex-post) for orders into the DA and ID markets.

8.9.21 This option focuses on the effect of the market participants' behaviour rather than the form of the behaviour itself (i.e. bidding principles). The RAs would introduce licence conditions specifying particular types of conduct as potentially constituting abuse, including:

- Acting alone or in collusion to materially prejudice the efficient price formation in the Day Ahead and Intra Day markets.
- Without good cause, limiting generation or capacity availability in ways that materially increase wholesale prices for electricity; or
- Pursuing discriminatory pricing policies by determining wholesale prices for electricity that differ unduly between times when market demand and cost conditions are otherwise similar.

8.9.22 The new licence condition would stop short of dictating that orders to the Day Ahead and Intra Day market should be cost reflective (SRMC), as is the case under options 1 to 3. The licence change would be consulted upon in time for I-SEM go-live.

8.9.23 The terms of the new licence condition as described above would apply to all market participants. However the SEMC is of the view that market participants with structural market power should be under closer scrutiny from the MMU. For that reason all of the licences' relevant conditions would have latent effect and would only apply to market participants deemed to have market power.

8.9.24 Market participants deemed to have structural market power would be obliged to report to the MMU periodically to demonstrate that their bidding strategies to the DA and ID market are compatible with competitive behaviour under an efficient market. These market participants would also be subject to closer scrutiny from the MMU.

8.9.25 The MMU would publish periodically the list of market participants which would have these additional reporting obligations arising from the market power licence condition. The methodology for the establishment of this list including the criteria that would determine inclusion on it will be consulted upon in the next stage of the policy development of the market power work stream. However the SEM Committee would like to invite views from market participants on what market metrics, thresholds and periodicity for calculation would inform of this assessment by the MMU and so trigger (or not trigger as appropriate) the licence reporting requirements.

8.9.26 The Initial view of the SEMC to use metrics such as HHI thresholds similarly to the ones used in the concentration model for the calculation of DC volumes or Residual Supplier Index to determine the list of participants with market power. Again this is something the SEMC would welcome market participants views.

8.9.27 In relation to the enforcement of this additional licence condition, the MMU, in determining whether the level of prices represent an abuse of dominance, would come to a view of the counterfactuals. That is, the MMU would evaluate whether pricing is excessive through an assessment of the level of prices that would have occurred without the alleged market abuse behaviour. This may also include evidence that long-run profitability exceeds an appropriate risk-base measure. Market Participants with structural market power would then be required to demonstrate, as required by the MMU, that their orders to the Day Ahead and Intra Day markets does not constitute a market abuse.

8.9.28 The new licence condition should be applied not only to generators but also to suppliers.

8.9.29 In summary, this option would have the following characteristics:

- A licence condition would be introduced outlining the high level principles in terms of market conduct.
- A latent licence condition requiring additional reporting would be in all licences but would only apply to market participants with structural market power.

- The MMU would periodically revise the list of market participants deemed to have structural market power.
- It would apply to both Generators and Suppliers

8.10 INITIAL ASSESSMENT OF OPTIONS FOR DA AND ID MARKETS

8.10.1 The SEM Committee does not believe it appropriate to implement prescriptive bidding controls in the DA and ID markets for all market participants (Option 1) as discussed in section 8.9. What follows is an initial RA assessment of Option 2 (Bidding Principles and Ex-Post Assessment), Option 3 (Ex-Post Assessment Only) and Option 4 Market Abuse Condition against the five key principles for this workstream detailed in section 8.3. The RAs would welcome stakeholder views and feedback on the options. Taking on board stakeholder consultation responses, the RAs will further analyse these options against the principles before coming to a decision.

Effective

8.10.2 As referred to in section 8.9, both Option 1 and 2 involve market participants demonstrating to the MMU ex-post that they have complied with the various metrics employed by the MMU as well as REMIT. For Option 2, the application of readily understood and enforceable ex-ante bidding principles would also be required. Whether it is possible to develop bidding principles which are sufficiently flexible and enforceable is a key issue which the RAs will be reviewing in considering the best option to implement. This is not an issue with Option 3. On the other hand, the RAs will need to consider whether Option 3 can readily and efficiently allow for enforcement by the RAs/MMU of SRMC pricing/outcomes from I-SEM go-live, without ex-ante principles being in place (aside from those in REMIT). This is an important criterion and will inform the relative scoring of the two options for the RAs in coming to a decision. The effectiveness of option 4 (and indeed all options) would be related to the capacity of the MMU to undertake complex analysis of market scenarios to determine counterfactuals to the market behaviour of market participants suspected to have abused the market. The option for would probably add another layer of complexity to the MMU work as this option does not rely on a single benchmark (i.e. SRMC bids).

Targeted

8.10.3 It is not currently obvious which option would be more targeted as all involve the MMU/RAs reviewing participant behaviour and market outcomes, using the variety of metrics referred to earlier. All options involve the MMU/RAs taking targeted ex-post action in relation to market participants as considered appropriate, informed by participants' conduct and market prices/performance, using the various metrics and REMIT. In Option 2 all generators would also have to comply with ex-ante bidding principles - and the impact on how targeted this would be would depend the level of flexibility enshrined within the bidding principles. Option 4 lends itself to more targeted intervention on those behaviours and outcomes deemed to constitute market abuse. It would also only apply to specific market participants for that reason this option would score high on this criteria.

Flexible

8.10.4 In relation to Option 2, the use of ex-ante bidding principles could potentially limit the flexible application of the market power measurement (compared with Option 3) for the RAs/MMU as it applies to all participants. However, as above the extent of this would depend on the wording enshrined in any such principles. Flexibility also implies the ability to sunset and re-introduce a market power mitigation measure if conditions warrant it. The publication of a set of bidding principles in Option 2 could be seen as less flexible than an ex-post assessment-only approach as it could involve market participant licence and other changes. Hence on “sunsetting” Options 3 and 4 may score higher than Option 2. Option 4 potentially allows the most flexibility in its application as the MMU could come to a holistic view when interpreting events of market abuse.

Practical

8.10.5 For Option 2 the application of readily understood and enforceable ex-ante bidding principles by the RAs/MMU would be required. In addition other issues such as licence changes would need to be considered. For Option 3, an issue is whether the approach can readily and efficiently allow for enforcement by the RAs/MMU of SRMC pricing/outcomes from I-SEM go-live. These issues will be considered by the RAs as referred to earlier. All options would in any event involve a significant level of market monitoring by the RAs using various metrics and REMIT. All options therefore involve the need for a well-resourced market monitor with the necessary systems/software and expertise in place by I-SEM go-live. Option 4 concentrates the MMU’s efforts into specific market participants at specific trading periods for that reason it would score high on practicality.

Transparent

8.10.6 Provided the bidding principles in Option 2 and the high-level metrics employed for both Option 2 and 3 are clear and transparent, both options should have a similar level of transparency. Both options could have transparency issues around SRMC not necessarily being required in every trading period, for example due to unit commitment issues as discussed in section 8.9; this is a function of not applying prescriptive SRMC bidding. Option 4 would allow greater discretion on behalf of regulatory intervention however the principles triggering these interventions would be clearly specified in a licence condition.

8.11 VERTICAL RING-FENCING

8.11.1 The RAs consider that vertical ring-fencing of the former incumbent players (referred to as "incumbents" for ease of reading), ESB and Viridian, has been effective in SEM working alongside other market power mitigating measures in ensuring that these companies do not gain any advantage in the broader market due to their overall size (see section 7 for more information). For I-SEM, the impact of vertical ring-fencing or integration on market participants' conduct or overall market performance is not something that can be easily modelled. This relates to both the wholesale and retail markets. This analysis, therefore, is qualitative in nature.

8.11.2 From a theoretical point of view, vertical integration can provide both efficiency benefits but can harm competition59. Therefore, a key consideration for an effective market power mitigation strategy is to determine whether the potential harm from vertical integration of ESB and Viridian would likely outweigh the potential benefits. If so, the continuation of ring-fencing as a market power mitigation measure in I-SEM would be warranted. In this context the RAs are considering the issue of ring-fencing of the incumbents in I-SEM, taking account also of the other proposed market power mitigation measures referred to earlier in section 8. The RAs would welcome stakeholder views on this matter. Relevant issues are discussed in the following paragraphs.

8.11.3 Studies on market power implications of vertical integration have been conducted in several international markets. A review of market power of a vertically integrated retailer and generator was undertaken in the Australian National Electricity Market (NEM)60. The paper notes that the non-contractual natural hedge of a vertically integrated player causes the retailer to reduce demand for fixed-price forward contracts, which in turn increases the incentive to exercise unilateral market power in the short-term wholesale electricity market, which raises the equilibrium spot price.

8.11.4 However, in the current GB Energy Market Investigation61, the CMA has provisionally concluded that vertically integration did not harm competition. This conclusion was in part based on CMA's analysis of wholesale market liquidity, which was found to be sufficient for independent firms to hedge their exposure to wholesale market risk in a similar way to VI firms. Although the six VI firms in GB exhibit different trading and hedging patterns than non-

[59] If the view is that it is more efficient to have the transactions within a single company rather than between two companies via a market, then that would imply that the more efficient model is having vertically integrated companies rather than markets. We note, however, that competition and competitive markets also provide efficiency benefits.

[60] A Comparison of Ex Ante versus Ex Post Vertical Market Power: Evidence from the Electricity Supply Industry, J, Gans & F. Wolak, 2012.

[61] https://www.gov.uk/cma-cases/energy-market-investigation

VI firms, they generally conducted their hedging strategies using products that were available and traded to all market participants, and there was no indication that VI firms were gaining an advantage by systematically using internal trades. Furthermore, the CMA found that all of the six large vertically integrated firms externally trade multiples of their combined generation and supply volume in electricity, and therefore they actually make a net positive contribution to liquidity. However, given substantial differences between the GB and SEM markets, findings from the CMA analysis should be extrapolated with caution.

8.11.5 I-SEM will represent a significant change in market design, and it is therefore appropriate to raises the question of whether vertical integration by the currently ring-fenced incumbents should be allowed for I-SEM go-live and/or at some stage in the future thereafter. If it were clear that the potential benefits (i.e. cost savings) from allowing incumbents to vertically integrate clearly outweighed the potential market power costs associated with, say, any negative impacts on forward liquidity or the risk of foreclosure, then allowing vertical integration would have a justification. However, currently there are no independent estimates of the cost savings from vertical integration, nor how forward market liquidity would evolve.

8.11.6 On the one hand there is the question of whether there is a need for vertical ring-fencing of the incumbents in I-SEM, especially in light of other market power mitigation measures that may apply as described earlier in this section. In addition there may be ongoing costs and efficiency issue associated with ring-fencing for the incumbents, especially with multiple trading periods in I-SEM.

8.11.7 On the other hand, merits of keeping vertical ring-fencing of the incumbents in I-SEM include:

- It offers some regulatory oversight whereby the RAs can at least view, although not set, ESB and Virdian Non Directed Contract (NDC) prices, thereby limiting their ability to exercise market power in the forward contracts market.

- It helps prevent ESB and Viridian having informational or pricing advantages with respect to their competitors which could deter competition and new entry, both in the wholesale and the retail market. For example, in an integrated ESB, Electric Ireland (ESB’s supply arm) would be aware of other supplier purchases of forward contracts from ESB, potentially providing it with an advantage over other suppliers. In addition, forward contracts could legitimately be offered to the supply companies of the former incumbents at different prices (and other terms and conditions) compared with those offered to other suppliers potentially negatively impacting on wholesale and retail competition;

- Keeping vertical ring-fencing of ESB's and Viridian's generation and supply businesses is consistent with the assumption adopted on the I-SEM building blocks development which holds that no policy previously decided by SEM Committee should be revisited unless it proves to be unworkable or incompatible with I-SEM.

8.11.8 On this basis, the SEM Committee is now considering the structural conditions, in combination with other proposed market power mitigation measures, in which vertical ring-fencing of the incumbents in I-SEM could be relaxed. The RAs would welcome stakeholder views on this matter.

8.11.9 Finally, given potential market entry, exit, mergers and divestments, as exemplified in the modelling on section 6, the SEM Committee is considering the conditions and criteria (or metrics) under which ring-fencing would be applied to non-incumbents. This would need to take account of other market power mitigation measures that would be in place. The RAs would welcome stakeholder views on this matter.

8.12 CONSULTATION QUESTIONS

8.12.1 Along with general comments, the RAs would welcome stakeholder views on the following questions:

- *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.*

- *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?*

- *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.*

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

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

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

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

9 NEXT STEPS

9.1 MARKET POWER POLICY TIMELINES

9.1.1 Comments to this Consultation Paper are requested from stakeholders by 18th January 2016, with comments to be sent in electronic format to both Gonzalo Saenz the CER at gsaenz@cer.ie and Joe Craig in the Utility Regulator at joe.craig@uregni.gov.uk .

9.1.2 The RAs will also hold a public workshop to discuss this consultation, in order to explain its proposals and to allow stakeholders air views. This workshop will be held in the Crowne Plaza Hotel in Dundalk on Wednesday 2nd December, from 14:00 to 17:00.

9.1.3 The RAs will then work to develop a Decision Paper on I-SEM market power mitigation policy, for publication in late March 2016, with a view to implementation workstreams commencing thereafter, facilitating I-SEM go-live in Quarter 4 2017.

9.2 DETAILED IMPLEMENTATION TIMELINES

9.2.1 Following the market power mitigation policy decision (expected in late March 2016, as above), from Quarter 2 2016 the RAs will commence associated detailed market power implementation workstreams with a view to facilitating I-SEM go-live in Quarter 4 2017.

9.2.2 This work includes any licence changes needed to facilitate the market power mitigation decision such as any changes needed to generation licences for FCOs and bidding rules. The RAs will also commence work on other implementation issues such as the detailed operation of the FCO (if decided upon), and any organisational issues arising, for example, in relation to the market monitoring activity of the RAs.

APPENDIX A: INTERNAL CONSTRAINTS IN SEM

Internal transmission constraints within the all-island market may create one or more smaller geographic markets. The RAs conduct ex-post studies on internal constraint levels in SEM[62], using four metrics:

- **Constraint payments**—i.e. payments to generator that are constrained off such, that their Dispatch Quantity is lower than its Market Schedule Quantity.
- **Proportion of energy payment attributable to constraints**—constraint payments as a percentage of overall wholesale energy payments (approx. 8% in 2013).
- **Infra-marginal rents earned through constraint payments**—when a generator is constrained off it will pay back to the market operator the savings in cost between the dispatch quantity and the market schedule quantity. In this case, it retains any difference between the SMP and the costs, which would have been incurred to deliver its Market Schedule (referred to as Infra-marginal rent). In 2013, monthly infra-marginal rents were in the range of €8-€16 million.
- **Constrained running**—this metric shows how energy volumes differ as a result of deviation from the market schedule. On average for the year 2013, the dispatch quantity deviated from the market schedule by roughly +20%.

The total constraint payments for 2013 (the latest year analysed) were close to €189 million. The TSOs' analysis suggests that internal transmission constraints are significant in the all-island market, and they often give rise to local geographic markets. Furthermore the analysis of the causes of constraint payments suggests that internal constraints are likely to be a continued problem in I-SEM.

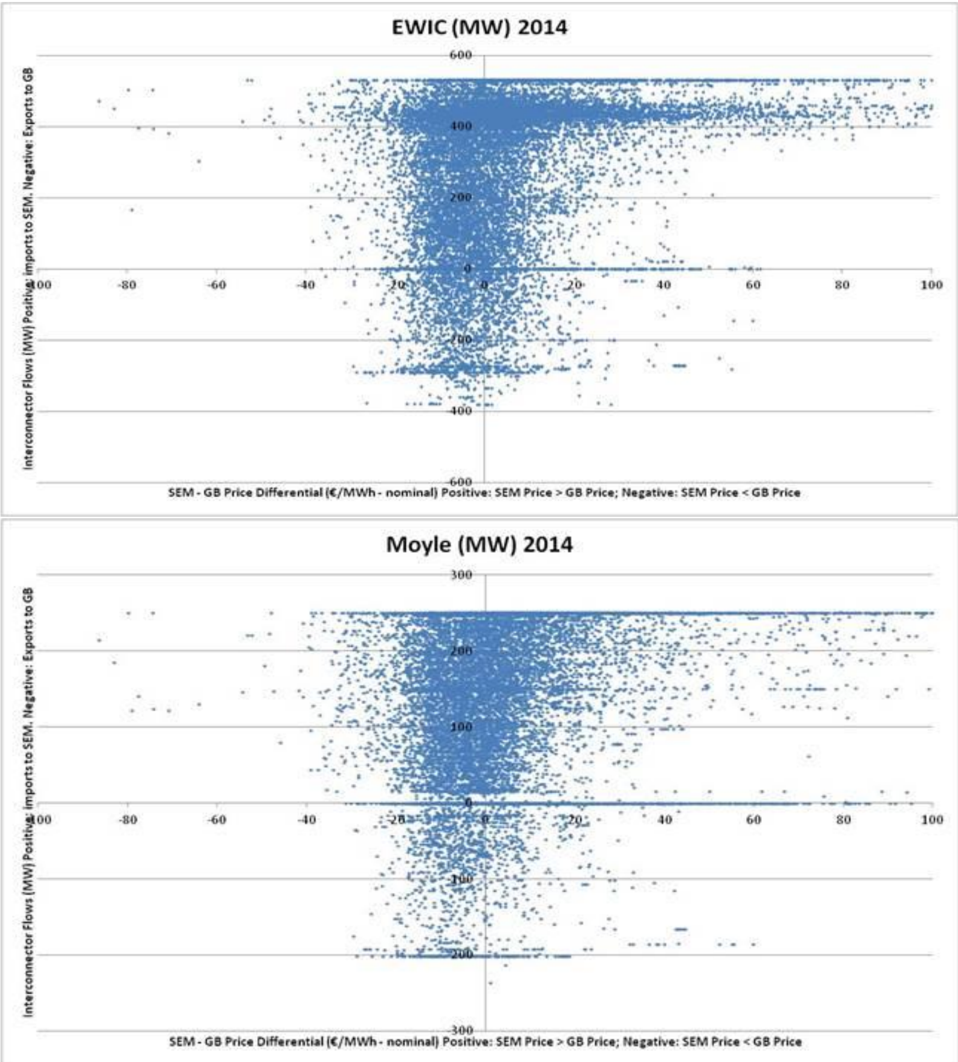
[62] SEM-15-013

APPENDIX B: HISTORIC FLOWS ON MOYLE AND EAST-WEST INTERCONNECTORS

Efficiency of interconnector flows refers to the notion that power should flow from the low-priced market to the high-priced market until either: (1) prices equalise, but for transaction/transmission costs; or (2) the interconnector capacity is fully exhausted.

The HLD Impact Assessment[63] found that interconnector flows between the SEM and GB markets have been quite inefficient, as illustrated in Figure C.1 below.

Figure C-1: Flows across Moyle and East-West interconnectors against SEM-GB price differentials in 2014[64]



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[63] SEM Committee Decision on High Level Design Impact Assessment, Section 4, SEM-14-085b, 17 September 2014

[64] HLD Impact Assessment, Figure 7.

Two types of inefficient flows observed in the above figures:[65]

- *Flows in wrong direction* (i.e., opposite the direction of prices)– shown by points in the top left quarter or bottom right quarter of the chart; and
- *Underutilised interconnector capacity* when a non-zero price differential exists

In 2013 GB wholesale prices were on average lower than the SEM wholesale prices, which is consistent with the fact that power flows in the direction from SEM to GB occurred only in 2% of the time. However, 33% of the time when the flows was from GB to SEM, the SEM price was lower than the GB price (i.e., the flow should have been in the opposite direction). The figure also shows (upper right and lower quadrant) that the interconnector capacity was underutilised a significant fraction of time. According to the findings from the HLD Impact Assessment this has not historically been the case between SEM and GB for reasons including:

- long gate closures in the SEM;
- the specific mechanisms for recovering start-up and no-load costs in the SEM (i.e., the uplift component of prices); and,
- participants' trading strategies.

[65] Points in the top right quarter of Figure C.1 represent flows from GB to the SEM when the price in GB is lower than the price in the SEM. Similarly, points in the bottom left quarter represent flows from the SEM to GB when the SEM price is lower than the GB price. Points in the other two quarters (bottom right and top left) represent flows in the opposite direction of the price differential for that individual pricing period.

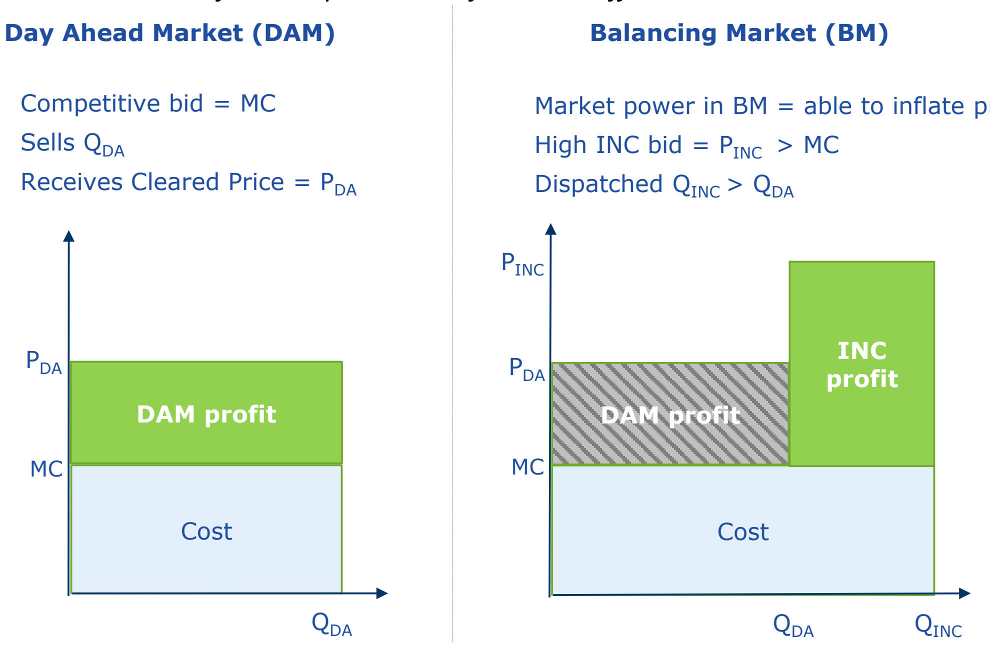
APPENDIX C: EXAMPLES OF I-SEM MARKET POWER IN PHYSICAL MARKETS

The interaction between the I-SEM DAM and the BM offers gaming opportunities for market participants who hold market power. If generators have a reasonable expectation of being dispatched up or down in the BM, they can obtain excessive profits by altering their incremental (INC) or decremental (DEC) bid offers.

For example, let us consider the case of a generator that behaves competitively in the DAM and submits offers that equal its marginal cost. Assuming the generator clears in the DAM with a quantity of QDA at a price of PDA, above its marginal costs, it will effectively earn a profit in the day-ahead market equal to the mark-up between the cleared price and its marginal cost times the quantity sold (assuming there are no other ex-ante trades already conducted in forward markets). For simplicity, let us also assume that the generator does not engage in any trades in the IDM.

If this generator holds market power in the BM and expects to be dispatched up, it can seek to inflate its INC offer above the competitive level (i.e. marginal cost). As the figure below illustrates, this will bring additional profits equal to the additional quantity dispatched (QINC – QDA) times the mark-up between the INC bid and the marginal cost.[66]

Figure E-1: Exercise of market power via inflated INC offers

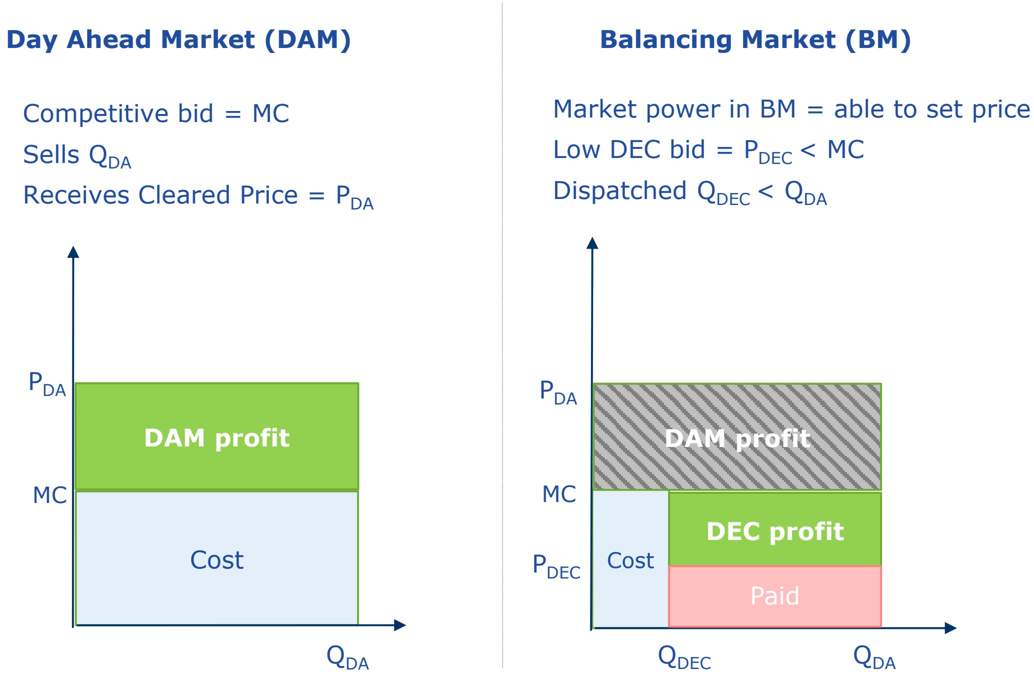


Similarly, if the same generator expects to be dispatched down in the BM, it has an incentive to reduce its DEC bid price, even below marginal cost. For each MW of

[66] Note that in this example the generator is needed by the TSO for a non-energy action.

output decrease compared to the DAM schedule, the generator will incur a cost equal to its DEC offer but will also benefit from cost savings associated with the reduced production. Because the DEC price is below its marginal cost, the cost savings achieved will be greater than the costs of buying the energy from the TSO resulting in a surplus profit earned by the generator. In addition, the generator will still receive the price P_{DA} for its DAM scheduled quantity Q_{DA}.

Figure E-2: Exercise of market power via reduced DEC offers



In the most extreme case, the generator would submit a zero DEC bid and be dispatched down to zero output, thus incurring no production costs, no costs for buying energy from the TSO but still receiving payment for the entire quantity and price sold in the DAM.

Other examples of potential exercise of market power in I-SEM are included in the table below.

Table E-1: Additional examples of potential exercise of market power in I-SEM

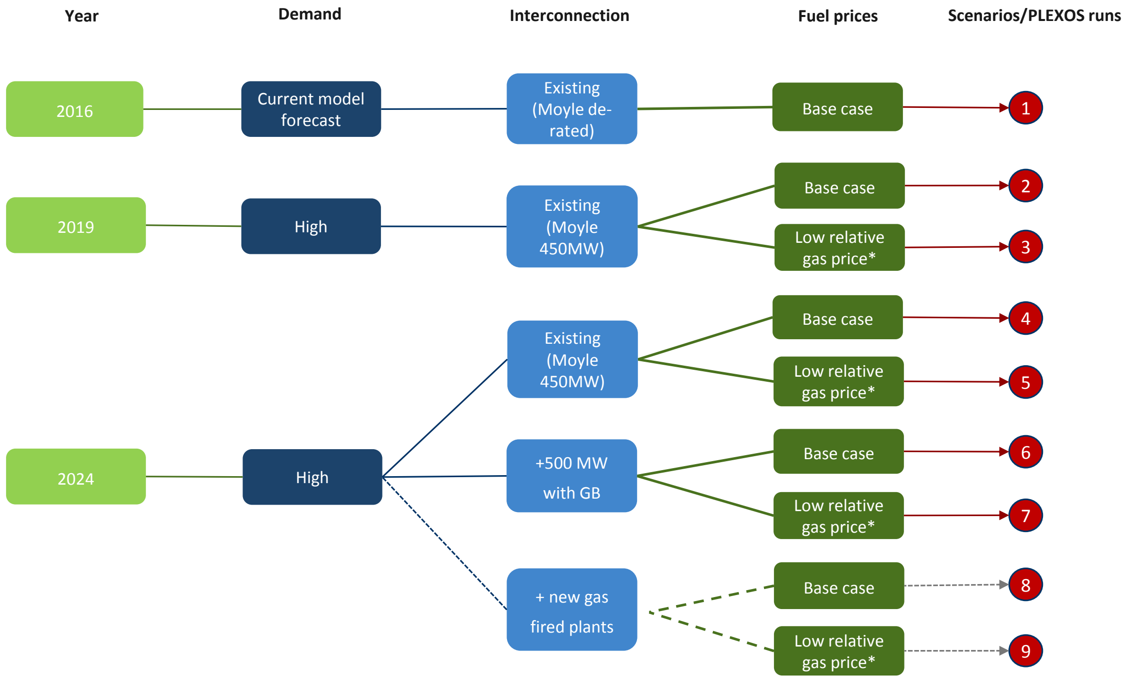
Case/scenario	Comments
Example 1: high wind output, few thermal units online, actual output wind generation > DA wind forecast	The few thermal generators online may have market power, play an INC-DEC game by putting in low DEC bids, knowing that the TSO must dispatch them down, thus depressing imbalance prices below efficient levels. This is an example of INC-DEC games.
Example 2: a generator with a DA schedule trips in an import-constrained area	If there are few other generators available to replace the generator on outage, and if those generators can reasonably expect to be pivotal, they may inflate the INC offers. Imbalance prices should not be affected since this is a non-energy action by TSO, but balancing costs will be higher. This is an example of INC-DEC games.
Example 3: a generator	If the generator can reasonably expect that the

Case/scenario	Comments
clears in DA but cannot be dispatched in real time due to transmission constraint	constraint will be binding, it may put in a very low DEC bid. As above, imbalance prices should not be affected since this is a non-energy action by TSO, but balancing costs will be higher. This is an example of INC-DEC games.
Example 4: strategic bidding by the owner of a larger thermal portfolio in response to aggregate wind generation	If the thermal generation owner has significant market power, it may inflate its offer prices when wind generation is low, and keep offers competitive when wind generation is high.

APPENDIX D: I-SEM MODELLING ASSUMPTIONS / RESULTS

The RAs Validated PLEXOS Model has been used to model market conditions in I-SEM for the years 2016, 2019 and 2024 under various scenarios. The figure below illustrates the nine scenarios modelled using PLEXOS. The modelling used demand and generation capacity data from the latest All-Island Generation Capacity Statement (GCS) for 2015-2024 published by the TSOs for all base case scenarios. For 2024 two additional scenarios have been modelled assuming an additional 500 MW interconnector capacity with the GB market and additional conventional generation capacity in the I-SEM, owned by new entrants. In addition, each scenario for 2019 and 2024 has been modelled using adjusted fuel price assumptions such that a reduction in gas prices relative to coal prices would lead to changes in the merit order of conventional generators.

Figure A.1: Scenarios modelled



The following tables include some of the specific assumptions made for the years modelled.

Demand and generation capacity assumptions

Table A-1: High-level modelling assumptions

Variable	Year	Assumption
Demand	2016	Current validated model assumption Total annual demand = 36,432 GWh
	2019	High demand scenario from GCS 2015-2024 Total annual demand = 38,362 GWh
	2024	High demand scenario from GCS 2015-2024 Total annual demand = 40,460 GWh
Wind capacity	2016	Current model assumption

Variable	Year	Assumption
		Installed wind capacity (end of year) = 3,609 MW
	2019	Wind installed capacity forecast as per GCS Installed wind capacity (end of year) = 4,665 MW
	2024	Wind installed capacity forecast as per GCS Installed wind capacity (end of year) = 5,498 MW
Interconnection	2016	Current available interconnection capacity (EWIC + Moyle derated)
	2019	Full EWIC and Moyle capacity available
	2024	<u>Base case</u>: full EWIC and Moyle capacity available <u>Alternative scenario</u>: additional 500 MW interconnector

Total installed wind capacity is allocated to wind regions proportionally according to current regional capacities. In the PLEXOS model, a wind capacity figure is specified for each quarter during the year. The installed wind capacity figures in the GCS are treated as capacity at the end of the respective year with the annual capacity increases allocated equally across all quarters.

Wind generation output is determined using the existing model wind profile uplifted for the increases in installed wind capacity. This produces a wind generation figure for each region for each half-hourly period. The average capacity factor is around 31% however the wind profile produces periods of high wind generation as well as periods of low wind generation.

Changes to conventional generation

The period to 2024 models changes to conventional generation capacity in the All-Island market. The 2015-2024 GCS envisages a number of plant retirements by 2019 and 2024 which have been captured in the modelling. These plant closures are shown in the table below.

Table A-2: Expected plant decommissioning

Plexos Unit ID	Unit name	Station ownership	Capacity (MW)	2019	2024
B4/B5/B6	Ballylumford Unit B4, B5 & B6	AES	250	Retired	Retired
TB1	Tarbert Unit 1	SSE	54	Available	Retired
TB2	Tarbert Unit 2	SSE	54	Available	Retired
TB3	Tarbert Unit 3	SSE	243	Available	Retired
TB4	Tarbert Unit 4	SSE	243	Available	Retired
K1 Coal 220	Kilroot Unit 1	AES	238	Available	Retired

Plexos Unit ID	Unit name	Station ownership	Capacity (MW)	2019	2024
K2 Coal 220	Kilroot Unit 2	AES	238	Available	Retired

The base case modelling scenarios assume new generation capacity totalling 160 MW will be added by 2019 and 2024. In addition to the base case scenario, an additional scenario has been modelled where further generation capacity has been considered as shown in the table below.

Table A-3: Expected plant commissioning

Plant	Type/Fuel	Capacity (MW)	2019	2024
Base case scenario				
Dublin Waste to Energy	Waste	62	Available	Available
New OCGT 1	Gas	98	Available	Available
Alternative scenarios				
New CCGT	Gas	297	Alternative scenario for 2024	
New OCGT 2	Gas	115	Alternative scenario for 2024	

Fuel prices

Fuel price inputs in the PLEXOS model have been determined based on quoted futures contracts, where available. The contracts used for estimating future fuel prices are listed in the table below. For coal, fuel oil and gasoil, quarterly price estimates have been used. Daily gas prices have been modelled using future monthly forward prices and a historic gas price profile (based on 2011 gas prices).

For peat and carbon prices, an annual price estimate has been derived. Peat prices, except for 2024, have been set at 0 to reflect priority dispatch status for power plants running on peat.

As futures prices to 2024 are not available for all products, a single fuel price forecast has been used for both 2019 and 2024 for all fuel prices. A separate carbon price forecast has been used for each year modelled.

Table A-4: Fuel price assumptions (base case)

Fuel	2016	2019	2024
Gas (daily)	ICE Natural Gas Futures for 2016	ICE Natural Gas Futures for 2019	
Coal (quarterly)	Coal (API2) CIF ARA (ARGUS-McCloskey) Futures for 2016	Coal (API2) CIF ARA (ARGUS-McCloskey) Futures for 2019	
Fuel oil	1% Fuel Oil Cargoes FOB	1% Fuel Oil Cargoes FOB NWE (Platts) Futures for	

Fuel	2016	2019	2024
(quarterly)	NWE (Platts) Futures for 2016	2019	
Gasoil (quarterly)	ICE Gas Oil LS Futures for 2016	ICE Gas Oil LS Futures for 2019	
Peat (annual)	Peat prices set at 0 to reflect priority dispatch for peat stations		Estimate of peat prices derived from BnM Annual report 2015.
CO2 ETS price (annual)	Thompson-Reuters Carbon's baseline EU ETS forecast for each year.		
UK carbon support (annual)	Support rate frozen at £18.08/t		Support rate set at £19.8/t

For the alternative fuel price scenario, gas prices have been discounted by 50% compared to base case levels.

Further Modelling Results: Evolution of market shares

Figure B-1: Installed capacity market share by company (base case scenario)

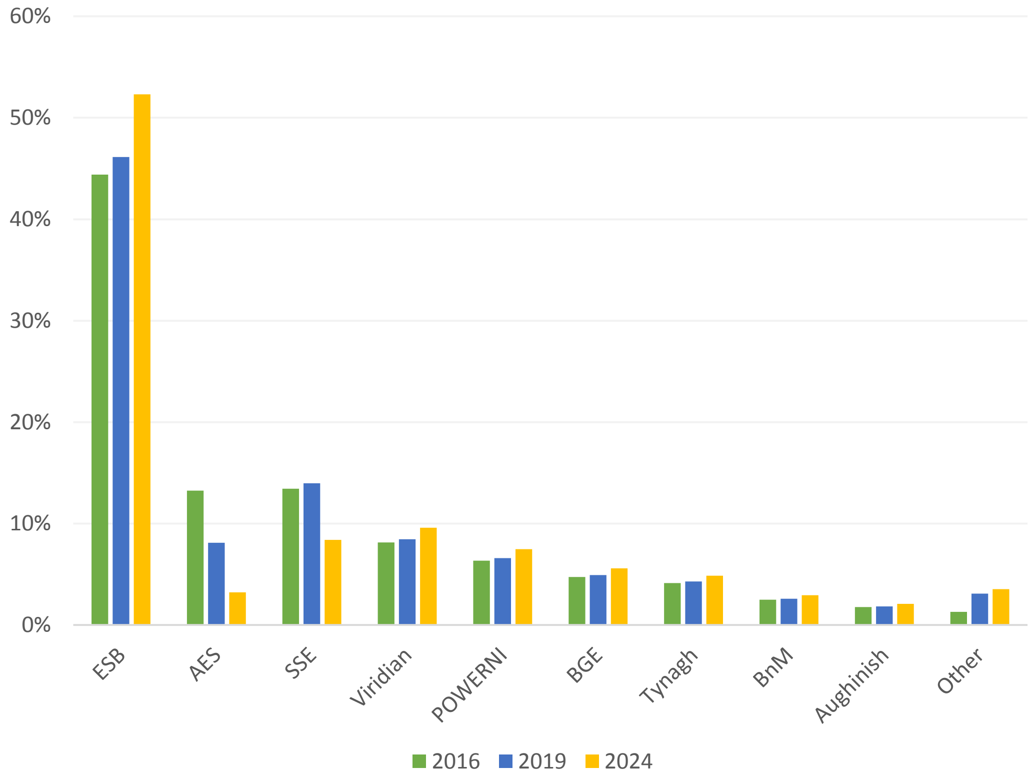
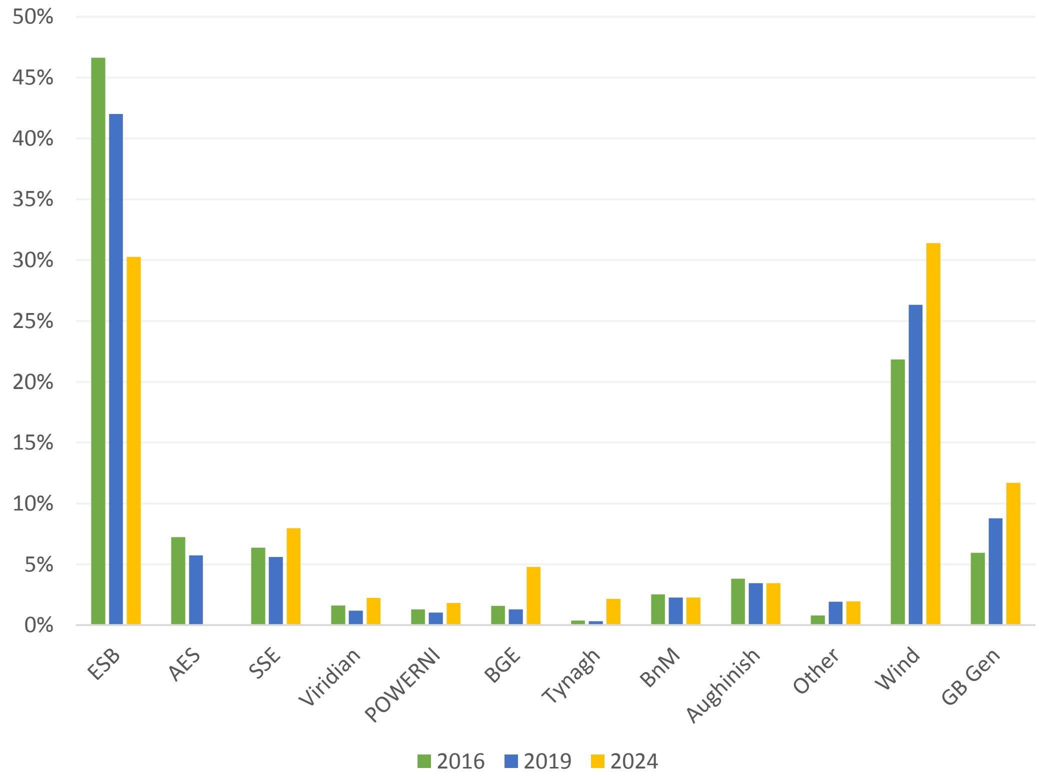


Figure B-2: Generation market share by company (base case scenario)



Further Modelling Results: Generation fuel mix

Figure B-3: Generation share by fuel type (base case scenarios)

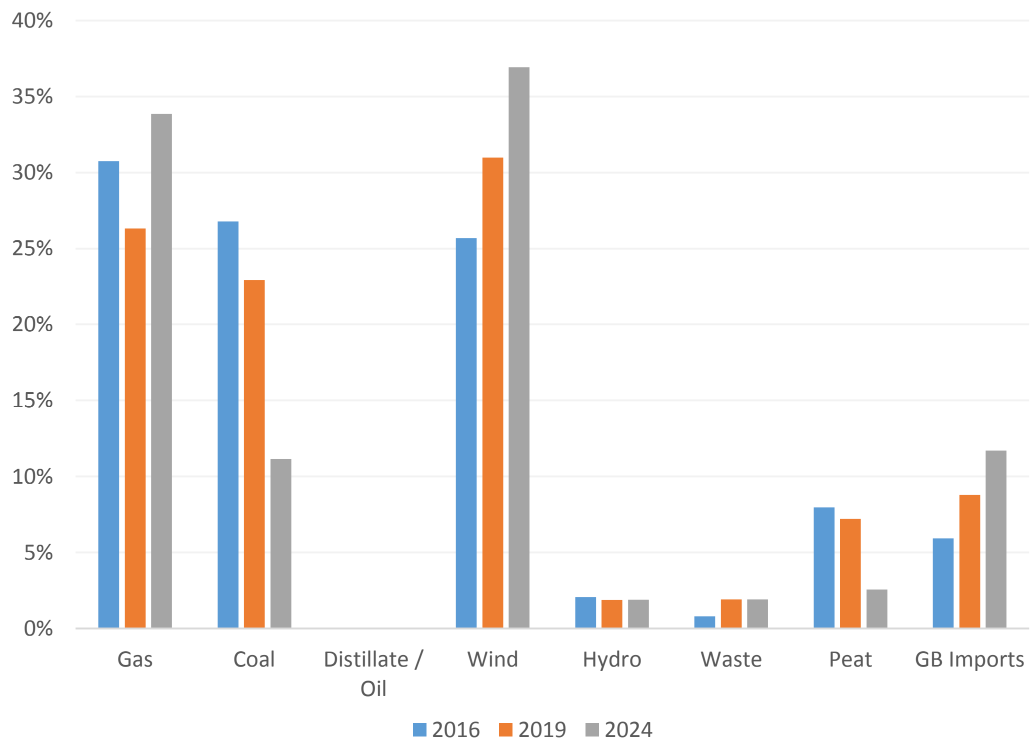
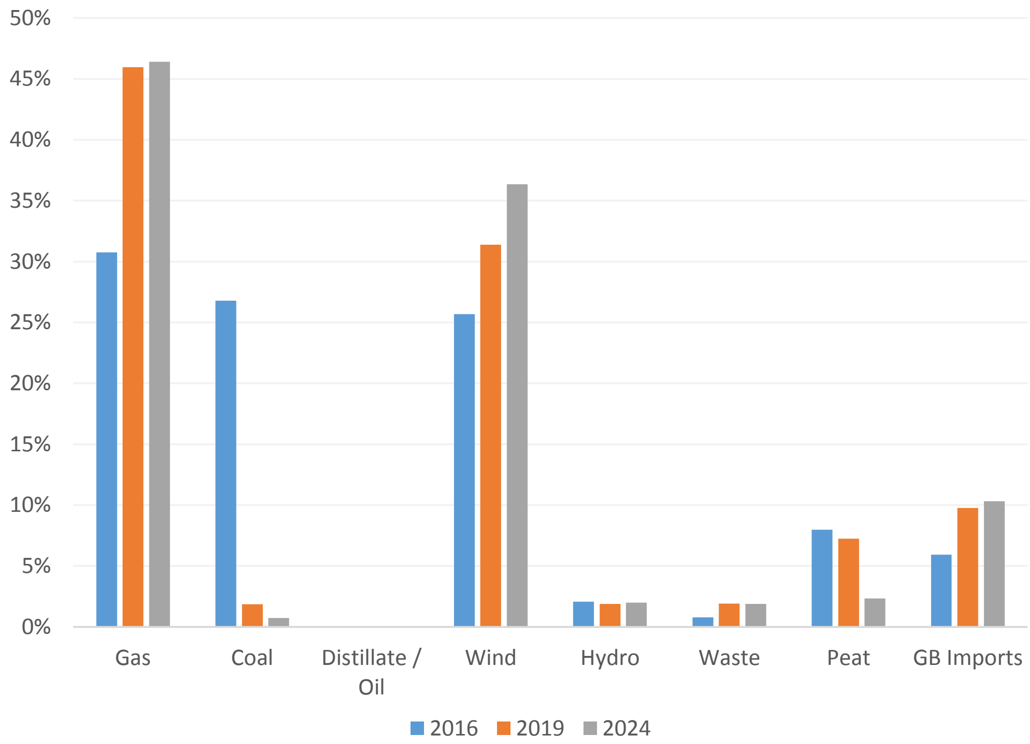


Figure B-4: Generation share by fuel type (low relative gas price scenario)



Further Modelling Results: Interconnector flows

Table B-1: Interconnector flows (base case scenario)

Measure	2016	2019	2024
Net flows (GWh)	- 1,271	- 2,525	- 4,452
% periods export	35.3%	33.3%	16.0%
% periods import	62.6%	66.6%	83.1%

Note: Net flows are calculated as quantity exported - quantity imported. A negative figure denotes net aggregate imports from GB into I-SEM.

Table B-2: Interconnector flows (low relative gas price scenario)

Measure	2016	2019	2024
Net flows (GWh)	- 1,271	- 3,154	- 3,630
% periods export	35.3%	29.0%	23.5%
% periods import	62.6%	70.9%	76.3%

Note: Net flows are calculated as quantity exported - quantity imported. A negative figure denotes net aggregate imports from GB into I-SEM.

APPENDIX E: AUTOMATED INTERVENTION IN BM – OPTION 2A

This appendix provides further information on the possible operation of bidding mitigation in the BM using an "automated intervention" as described in Option 2a in section 8 of the paper. Specifically, for this option the TSO would need to be able to perform the following steps:

- *Identify real-time information about each relevant constraint* which can give rise to a local market in the BM. Specifically, for each such constraint, the TSO would need to know whether a particular constraint is binding at a given time, including the associated shadow price (i.e., the reduction in dispatch costs associated with a unit increase in the constraint limit);

- *Determine constraint relief demand (CRD)*, defined as the total MW needed by the TSO for redispatch to ensure that the constraint is not violated. CRD would be zero whenever a constraint is not binding, and the local market power mitigation process with respect to that constraint would stop;

- *If a constraint is binding, generators capable of providing MW relief to the TSO with respect to that constraint would have to be identified.* For example, for the thermal transmission constraints, this would be determined based on the generation shift factors[67] of every unit with respect to the constraint. Units capable of providing relief could be selected subject to a minimum impact threshold, i.e., only units with a shift factors above a minimum threshold would be selected;

- *Next, effective supply of MW relief of each generator would have to be identified.* Total effective supply should not include all MW that can provide relief, since very high-priced offers may provide little to no competitive pressure to prevent an exercise of market power. Therefore, total effective supply should only include MW relief that is available at an offer price below a pre-specified maximum price[68];

- Lastly, a structural market power test would have to be calculated using the following type of 3 PST formula for each generation owner[69]:

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[67] Shift factors, also known as Power Transfer Distribution Factors, represent the change in active power fows on a transmission line with respect to a change in injection at bus and a corresponding change in withdrawal at the reference bus. Thus shift factors describe whether a generator increasing its output relieves or aggravates a constraint, including the magnitude of that impact.

[68] For example, in PJM only offers below a Unit Effective Price (UEP) are considered, where UEP is defined as System Marginal Price + 1.5 x constraint shadow price x generation shift factor with respect to the relevant constraint.

[69] This is how the 3 PST test is calculated in PJM. See http://www.pjm.com/~/media/committees-groups/task-forces/gofstf/20150722/20150722-item-02-imm-tps-education.ashx.

$$\mathrm{PST_j} = \frac{\sum_{i=1}^{n} s_i - \sum_{i=1}^{2} s_i - s_j}{\mathrm{CRD}}$$

where $\sum_{i=1}^{n} s_i$ is the total supply of MW relief in the local market; $\sum_{i=1}^{2} s_i$ is the supply of the largest two suppliers (apart from the one being tested); and s_j is the supply of the generation owner being tested. A supplier would fail the test if the value of PST were less than one.

Figure 8.1 summarises the types of current constraints monitored by the TSOs on the island. As shown the TSOs generally monitor constraint groups, rather than individual constraints. One exception is the North-South Tie-Line Limit to which the above process could be applied.

Figure 8.1: Types of constraints currently monitored by the TSO

Reserve (Frequency Limits)	Thermal	Voltage	System (Dynamic)
• All Island OR Requirement	• North-South Tie-Line Limit	• Coolkeeragh Must Run	• SNSP
• NI / IRL Min OR Requirement	• Ballylumford Export Limit	• Kilroot Must Run	• RoCoF
• NI / IRL RR (OCGT) Limitation	• Various Dublin Must Run	• Various Dublin Must Run	• Inertia
• NI / IRL Negative Reserve	• Cork Export limit	• South West Must Run	• NI 3 Units Must Run
		• Moneypoint Must Run	• IRL 5 Units Must Run