

Integrated Single Electricity Market (I-SEM)

High Level Design for Ireland and Northern Ireland from 2016

(SEM-14-008)

Power NI's Response

4th April 2014

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Executive Summary

Power NI welcomes the opportunity to respond to the consultation paper published by the Regulatory Authorities (RAs) on the High Level Design for the Integrated Single Electricity Market (I-SEM).

The changes to the current wholesale electricity trading arrangements contemplated by this work programme represent the most significant change to the electricity industry since the implementation of the Single Electricity Market (SEM) in 2007.

The 2016 deadline for I-SEM implementation is a significant challenge for the RAs and market participants. Power NI believes that this current round of engagement and consultation has been worthwhile. It is important to recognise however that significant time was lost in earlier rounds of consultation, in establishing the RAs project office and in appointing consultancy support.

The RAs should be cognisant that given the 2016 deadline this project is now on the critical path. Such time pressure should however not prompt the RAs to negate due process in thoroughly assessing both the high level and detailed design of the market. Compressed timetables have, in previous major market projects, led to a shortening of the design phase and a compression of the implementation and testing phases. This represents a significant risk to the market and its participants.

Given such time pressure it may be a natural reaction for the RAs to take comments away and move through the high level decision recommendation and aspects of the detailed design in isolation. Power NI strongly urges the RAs not to follow this course of action. The RAs have the opportunity to avail of a significant level of market expertise and will secure a better functioning outcome through a high level of interaction with market participants.

Any option chosen must have been consulted upon, a hybrid between two or more options could have unintended consequences that would be highlighted by market participants during a consultation process and therefore carry high risk.

In defining the high level design of the I-SEM, the RAs must be cognisant of their statutory duty to protect consumers. Only the largest of commercial customers are realistically in a position to dynamically interact with the market place. All small and medium enterprises and domestic customers' source, and will likely continue to source, their electricity needs via a supplier. Even mindful of the aspirational goals of smart metering and demand side participation, the overwhelming demand from customers is, and will continue to be, a requirement to have certainty and consistency in electricity pricing.

To deliver this requirement, suppliers must offer fixed, non-volatile tariffs that can be easily presented. Simplicity in market design is key to customer engagement. To this end it is imperative that suppliers are able to hedge the majority of volume in the forwards market to ensure tariff stability, cognisant that the price in the forwards market is the price consumers pay. It is therefore crucial that any design

has a properly functioning forwards market in terms of volume, price and flexibility i.e. liquid.

Liquidity is a term which has been used extensively throughout the high level design considerations. Dependent upon a participant's perspective however, liquidity is important in different timeframes.

There is a pre-conception that liquidity is simply volume; this is not the case. Liquidity refers to availability of hedges based upon a competitive price formation, covering a variety of timeframes at times when there is demand to buy them, not purely when generators choose to sell.

Liquid and transparent forward markets enable suppliers to hedge efficiently; they shield consumers from volatile spot markets and facilitate competitive tariff structures. Effective forward markets also provide open access to mitigate market power and concentration, and send price signals to drive investment. The effective functioning of a forward markets is therefore vital for competition and consumer choice.

When considering the theoretical aspects of the market design therefore, it would be incorrect to assume that by ensuring a strong day ahead price (such as via Option 3) this would provide such a robust reference price that it will encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however the SEM suffers from a chronic lack of liquidity in the forward market.

In the current SEM there is a high level of demand for a wide range of hedges but a distinct lack of products being offered and traded. Power NI firmly believes that the current SEM arrangements result in an inefficient, uneconomic forwards market that is placing a price premium on domestic and small/medium enterprise customers.

At the beginning of the SEM, Power NI could set regulated tariffs in Northern Ireland based upon a hedged level of circa 90%. When setting the current tariff hedging levels were circa 30%. This represents a significant risk for suppliers, making it increasingly difficult to provide certainty in tariff setting and increasing the likelihood of a volatile end customer proposition.

The key 'big ticket' items which are affecting the operation of the current forward market are thermal generation uncertainty and market dominance.

Uncertainty of dispatch can mean that unless market participants have a diversified generation portfolio, offering Contract for Differences (CfDs) in the forwards market will create a risk exposure. This uncertainty has been steadily increasing since the market began in 2007 with the levels of renewable generation connected to the system pushing thermal generation further down the merit order.

The current SEM also suffers from a market dominance issue which should be addressed in the I-SEM design. Long term hedging is offered almost exclusively

by one market player and a significant price differential can be seen between directed and non directed contracts offered. One seller without competition, with an internal buyer and coupled with a general scarcity drives prices upwards.

Power NI believes that market power mitigation was not effectively considered in the design of the SEM with Directed Contracts being mandated relatively late in the process and no consideration given to the forwards market and whether it would operate effectively. To fail to consider this issue in the design phase of the I-SEM repeats a fundamental SEM design flaw which has pushed scarcity premiums to end consumers.

The implementation of the SEM significantly increased the collateral requirements placed upon suppliers. Pool exposure accompanied by hedging activities has required suppliers to have in place high value letters of credit or cash deposits. This collateral requirement is a burden on suppliers, requires financing, potentially acts as a barrier to entry and the associated costs ultimately appear in a customers bill.

Power NI believes that the I-SEM should look wherever possible to minimise the collateral requirements to a reasonable level. Participation in the market should be encouraged and the costs minimised.

While it may not be immediately considered relevant to a supplier, the financeability and stability of generation in the market is an important consideration.

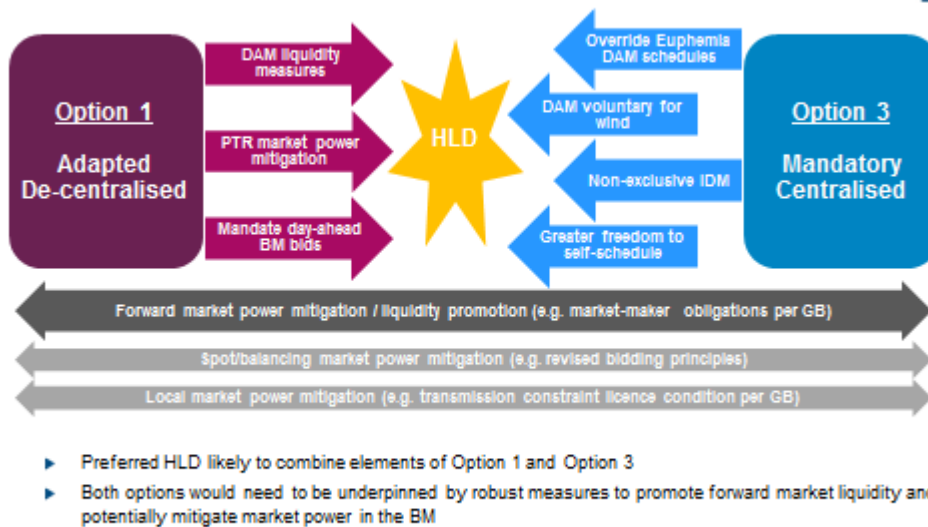
Power NI is concerned that by failing to consider the three strands of generator income as a package, risks either an over payment (or double payment) to generation, inefficient signals which could result in payment for capacity that is no longer required (due to deficient exit signals), or price scarcity due to an inefficient entry signal.

Each of these scenarios would result in a higher cost outcome for customers and therefore Power NI would encourage the RAs to take a holistic view to the consideration of generator financeability across the energy, capacity and ancillary/balancing services markets.

In relation to the design options, Power NI considers Options 1 and 3 as being a continuum rather than competing options at opposite ends of a spectrum. Power NI believes beginning with Option 1 and including simple market power mitigation and some of the other aspects of Option 3 can offer the ideal outcome for the market across the timeframes.

The figure below attempts to pictorially describe what could provide the optimal market outcome.

▶ Refining the HLD Options



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With relatively simple market power mitigation, liquidity could be secured in the forwards market as well as the DAM. A supplier can be afforded the freedom to actively trade with the market maker, independent generation and/or with lower cost renewable generation when available. The market maker obligations can provide a clear reference price with other thermal generation competing in the certainty that they will be physically firm if contracted. This creates an active forward market.

Trading over the interconnectors can be optimised by clear physical rights with limitations placed on any one participant to prevent the exercise of market power to ensure efficiency in later time frames. Physical positions secured in the forwards market can also be traded for lower cost generation in the DAM and IDT timeframes with both generators looking to trade their position for a lower cost one, and suppliers looking to refine short or long positions. Ensuring that the DAM is voluntary to wind may also alleviate some of the forecasting risk inherent with renewable generation.

This potential enhanced option, effectively gives the RAs the ability to ensure that all market timescales are efficient and the optimal outcome is achieved. It also gives flexibility to adapt to future changes and does not rely upon theoretical drivers of behaviour.

In relation to the question of capacity; the current SEM Capacity Remuneration Mechanism (CRM) provides a significant income stream for generating participants. From a supplier perspective it is important to recognise that the current CRM does provide important investment signals for generation capacity provision while dampening energy price volatility in the SEM.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

Power NI acknowledges that there are flaws with the current CRM scheme. There is a clear lack of distinct exit signals which could potentially be managed through a well-designed and consulted upon testing regime and the current scheme does not encourage the required generation characteristics such as flexibility.

In balancing the benefits of a CRM and acknowledging the flaws, Power NI considers the I-SEM design phase as offering an opportunity to refine the CRM in order to continue providing the benefits of dampening of price volatility, a stable regulatory environment, investment signals and generator financeability; whilst targeting the flaws of a lack of exit signals and rewarding flexibility.

Introduction

The changes to the current wholesale electricity trading arrangements contemplated by this work programme represent the most significant change to the electricity industry since the implementation of the SEM in 2007.

As the RAs are aware, Power NI is the largest electricity retailer in Northern Ireland. Power NI is part of the Viridian Group which has within in its portfolio a retail position in Northern Ireland and the Republic of Ireland, as well as a significant thermal and renewable generation presence.

To support Viridian's review of the high level design phase and with regulatory approval, Baringa and NERA have provided a number of expert reports in key areas of consideration. These reports have been included as appendices to this response and are referenced as appropriate.

Power NI is however a separate business. Power NI's legal, managerial and operational separation is mandated via licence condition. It is within the context of being a supplier without vertical integration that Power NI has considered the high level design requirements and assessed the options presented.

The principles behind the European Target Model aim to maximise interconnector usage for cross border trade while sourcing the most cost efficient production. While at a high level these goals are laudable, there is a risk that real benefits to consumers may not be realised should the detailed arrangements not be fully analysed or the solution be costly to implement. Power NI recognises that the RAs are cognisant of their respective statutory duties and have set high level principles for the market. This is an important cornerstone on which to build a detailed design.

The 2016 deadline for I-SEM implementation represents a significant challenge for the RAs and market participants. Power NI believes that this current round of engagement and consultation has been worthwhile. It is important to recognise however that significant time was lost in earlier rounds of consultation, in establishing the RAs project office and in appointing consultancy support.

The RAs should be cognisant that given the 2016 deadline this project is now on the critical path. Such time pressure should however not prompt the RAs to negate due process in thoroughly assessing both the high level and detailed design of the market. Compressed timetables have in previous major market projects led to a shortening of the design phase and a compression of the implementation and testing phases. This represents a significant risk to the market and its participants.

Given such time pressure it may be a natural reaction for the RAs to take comments away and move through the high level decision recommendation and aspects of the detailed design in isolation. Power NI strongly urges the RAs not to follow this course of action. The RAs have the opportunity to avail of a significant level of market expertise and will secure a better functioning outcome through a high level of interaction with market participants.

Power NI would also welcome a Regulatory Impact Assessment carried out against each option or at least a targeted number of the options, coupled with the completion of a robust cost benefit analysis.

As stated above, Power NI would welcome further engagement from the RA's and the Departments (DETI and DCENR) throughout this process as well as any questions or comments that they may have in relation to this response.

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General Comments

Before considering the specific questions posed by the RAs in the consultation paper Power NI has a number of general comments in relation to a range of issues. The specific questions are addressed in Appendix 1.

Evaluation Criteria

The RAs have determined, via the earlier consultation and decision phases, that the objectives of the SEM should be maintained with the addition of compliance with the Internal Energy Market i.e. the European Target Model. These criteria provide a useful reference point for assessment and consideration of the options.

Power NI supports the use of such assessment criteria and believes that they cover the areas of consideration when reviewing the high level design. The criteria are somewhat subjective and therefore correctly form part of the qualitative assessment.

As per the previous decision paper, and restated in Section 1.2.4, the evaluation criteria are –

- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.
- **Practicality/Cost:** the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation, and consumption of electricity in a fair and reasonable manner.
- **Competition:** the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- **Adaptive:** The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.

Many of these criteria place competing requirements on the high level design options. While Power NI concurs with the RAs assessments that the security of supply requirement will be met by the actions of the TSOs, it is important to recognise that the TSOs can only dispatch plant which is available to them. Security of supply therefore should consider the financeability, stability and entry/exit signals given to generation participants.

The stability and adaptive criteria are clearly linked. The market design should provide certainty of implementation to participants yet be flexible enough to adapt to developments in both technology and markets.

Efficiency and competition are important considerations in terms of outcomes and specifically how those outcomes impact customers. As a supplier delivering products to end consumers these criteria are vital.

Practicality and equity in terms of cost are also important as ultimately the end consumer will bear the burden. In relation to equity of participation the RAs should be mindful of the burden placed on suppliers of excessive and multiple credit requirements as well as asymmetrical currency exposures created by the various options.

Equity of operation is impacted by the environmental criteria. It should be recognised that renewable generation is subject to priority dispatch. Such dispatch arrangements while implemented for laudable reasons, have an impact on the behaviour of other generation and have consequences in the different timeframes which ultimately impact suppliers. It is questionable therefore if equity is structurally achieved due to policy considerations.

Compliance with the Internal Electricity Market is the only criteria added to those in place through the lifetime of the SEM. It will be important to balance the compliance requirement. Where areas of interpretation exist the approach should be shaped to maximise the optimisation of the Irish market structure. An overly literal interpretation when not required may fetter the discretion of the RAs. Equally however the RAs must be mindful of not straying from the European requirements and risking a breach and subsequent market change obligation.

Power NI's key considerations

When considering the high level design, the key aspects of the market from a supplier's perspective are the ability afforded by the market structure to manage risk, hedge exposure in the forwards market and the inherent liquidity which facilitates such activity. This requirement speaks directly to the efficiency, competition and equity assessment criteria.

In previous consultations, Power NI highlighted that the focus of the limited information published at that time had been on generator participation. Power NI acknowledges that the RAs have gone some way to recognise the counter

balancing supplier participation when providing information in this round of consultation and engagement.

As a stand alone, non-vertically integrated supplier, Power NI is concerned that changes to the market structure could further reduce available hedging and risk management opportunities. The pricing regimes in any balancing, day ahead or intra day market must not inhibit participation in the forward market. Consumers and therefore suppliers desire price certainty. Securing volumes in quantities over and above a refinement level in later markets may add a risk premium if sufficient liquidity is not available to all supply participants. Given the size and nature of the Irish market, simple risk management opportunities should be available either through market structures or via regulatory mandate.

Power NI believes that the questions surrounding practicality, participation and risk management opportunities for suppliers must be addressed by the RAs. The differing effects of potential pricing algorithms, the operation of power exchanges and the practicalities of trading arrangements will all determine the effectiveness of the market.

Liquidity is a term which has been used extensively throughout the high level design considerations. Dependent upon a participant's perspective however, liquidity is important in different timeframes.

There is a pre-conception that liquidity is simply volume; this is not the case. Liquidity refers to availability of hedges based upon a competitive price formation, covering a variety of timeframes at times when there is demand to buy them, not purely when generators choose to sell.

The RAs have a statutory duty to protect consumers. Only the largest of commercial customers are realistically in a position to dynamically interact with the market place. All small and medium enterprises and domestic customers' source, and will likely continue to source, their electricity needs via a supplier. Even mindful of the aspirational goals of smart metering and demand side participation, the over whelming demand from customers is and will continue to be a requirement to have certainty and consistency in electricity pricing.

To deliver this requirement, suppliers must offer fixed non-volatile tariffs that can be easily presented. To this end it is imperative that suppliers are able to hedge the majority of volume in the forwards market to ensure tariff stability, cognisant that the price in the forwards market is the price consumers pay. It is therefore crucial that any design has a properly functioning liquid forwards market in terms of volume, price and flexibility i.e. liquid.

This customer requirement has been clearly demonstrated both in Northern Ireland when domestic customer tariffs were reduced in 2012 then increased in 2013, and the current political pressure in the UK to freeze prices. Such certainty can only be delivered if a supplier is able to hedge long term exposure via contracts available in a liquid forwards market.

Liquid forward, day-ahead and within-day markets are therefore essential components of a well-functioning electricity market. In addition to providing suppliers with the ability to meet customers' needs as explained above, they also stimulate competition by allowing parties to manage risk, offer stable prices and support new investments.

Liquid, transparent and competitive forward markets enable suppliers to hedge efficiently; they shield consumers from volatile spot markets and facilitate competitive tariff structures. Effective forward markets also provide open access to mitigate market power and concentration, and send price signals to drive investment. The effective functioning of a forward markets is therefore vital for competition and consumer choice.

Power NI requested Baringa to look specifically at the issue of liquidity and have included their report in Appendix 2 for the RAs further consideration.

An additional and important consideration for Power NI is the operation of the balancing market. Suppliers will be subject to forecasting risk; this is unavoidable and it would be contrary to the principles of equity if the balancing costs for such imbalance are punitive. Power NI believes that balancing costs should reflect the balancing actions taken by the TSOs. As the costs will ultimately be borne by consumers the RAs should ensure that balancing risk to suppliers remains equitable.

This issue also extends to the operation of global aggregation and the apportionment of the residual error in the new marketplace. This will be exclusively a balancing cost to a supplier and Power NI believes the current method inequitably pushes cost to the domestic and small/medium sized non-domestic customer. The residual error occurs due to a range of factors not just quarterly or bi-monthly estimation. Meter errors, fraud, Distribution Loss Adjustment Factors (DLAFs) and Transmission Loss Adjustment Factors (TLAFs) all contribute yet are not shared equitably. To layer a punitive balancing charge on to this compounds the inequity. Power NI believes that in all market design options the allocation of residual error should be revisited in the detailed design.

Current Market Issues

The forwards market in the current SEM suffers from a number of significant deficiencies. The reform of the wholesale market affords the RAs an opportunity to address the detrimental aspects of the current market and move towards a properly functioning market across all of the timeframes.

In the current SEM there is a high level of demand for a wide range of hedges but a distinct lack of products being offered and traded.

The issues with the forwards market today include -

- Lack of volume,
- Infrequent nature of auctions,

- Lack of transparency,
- Market dominance,
- Inexplicable price spreads,
- Scarcity premiums,
- Market exit (financial players have exited the European commodities market following the implementation of EMIR e.g. Deutsche Bank, Bank of America/Merrill Lynch and JP Morgan)

Power NI firmly believes that these issues have led to an inefficient, uneconomic forwards market that is placing a price premium on domestic and small/medium enterprise customers.

The key 'big ticket' items which are affecting the operation of the current market are market dominance and thermal generation uncertainty.

Uncertainty of dispatch can mean that unless market participants have a diversified generation portfolio, offering CfDs in the forwards market will create a risk exposure. This uncertainty has been steadily increasing since the market began in 2007 with the levels of renewable generation connected to the system pushing thermal generation further down the merit order.

At the beginning of the SEM, Power NI could set regulated tariffs in Northern Ireland based upon a hedged level of circa 90%. When setting the current tariff hedging levels were circa 30%. This represents a significant risk for suppliers, making it increasingly difficult to provide certainty in tariff setting and increases the likelihood of a volatile end customer proposition.

The current SEM also suffers from a market dominance issue which should be addressed in the I-SEM design. Long term hedging is offered almost exclusively by one market player and a significant price differential can be seen between directed and non directed contracts offered. One seller without competition, with an internal buyer and coupled with a general scarcity drives prices upwards.

Baringa have also considered this aspect of the market design in their report included in Appendix 2.

Addressing these issues in the I-SEM design would be a significant improvement in the operation of the wholesale electricity market in Ireland.

Market Power Mitigation in the I-SEM

Market power mitigation is both an emotive and difficult issue to address. At a philosophical level the RAs may be inclined to consider the market design in isolation and allow the market deal with issues of power and dominance in an evolutionary or theoretical manner. Power NI would strongly advise against proceeding to a high level design decision without detailed consideration of the market power mitigation options available.

Given both the size of the Irish market and the players within it, along with the chunky nature (in terms of relative size) of the generation units and the interconnection available, to fail to consider market power mitigation would represent a fundamental failure by the RAs, result in a sub-optimal design and be contrary to the RAs statutory duty to protect consumers.

Power NI believes that market power mitigation was not effectively considered in the design of the SEM with Directed Contracts being mandated relatively late in the process and no real consideration given to the forwards market and whether it would operate effectively. To fail to consider this issue in the design phase of the I-SEM repeats a fundamental SEM design flaw which has pushed scarcity premiums to end consumers.

Experience from the GB market also suggests that a liquid day-ahead market will not necessarily develop in a market design based on self-dispatch without regulatory pressure, and a liquid day-ahead market, whilst a pre-requisite, is not necessarily a driver for a liquid forward market without further intervention. This is particularly the case where there is a high degree of vertical integration.

When considering the theoretical aspects of the market design therefore, it would be incorrect to assume that by ensuring a strong day ahead price (such as via Option 3) this would provide such a robust reference price that it will encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however the SEM suffers from a chronic lack of liquidity.

From the experience in the SEM and GB, Power NI has concluded that there will be a requirement for additional measures to stimulate forward market liquidity regardless of the choice of HLD option. Furthermore, under Option 1 where the Day-Ahead Market (DAM) is not mandatory, Power NI believes that additional measures will likely be required to guarantee sufficient liquidity at the day-ahead stage to ensure effectiveness of day-ahead market coupling, and reliable pricing for settling forward financial contracts, REFITs and future CfDs.

The measures that could be used to encourage forward market liquidity include:

- Directed Contracts, as under the current SEM.
- Market maker obligations on certain players, as required by Ofgem in GB under its 'Secure and Promote' proposals and suggested under Option 1 in the I-SEM consultation document.
- Self-supply restrictions on certain players.

The advantages of Directed Contracts are that they provide suppliers certainty of price against which they can set their retail tariffs and are familiar to current SEM participants. However they do not provide any liquidity benefit to independent generators, and require the RAs to take a direct role in setting wholesale prices, which ultimately is not part of the vision for the Electricity Target Model.

The market maker obligations do not specify an absolute price level (although some form of pricing requirement could be a feature), but require the dominant

player to make a minimum volume available in the forward market on both the buy and sell side within a maximum specified bid-offer spread. This provides liquidity to all market players, not just suppliers. These obligations should help to underpin the development of the forward market, without directly intervening in forward price levels and are similar to obligations mandated in other European countries.

Self-supply restrictions can also stimulate forward liquidity without directly intervening on price, but do not guarantee liquidity to the same extent as market maker obligations. They can also be harder to enforce although may be useful in the portfolio of market power mitigation.

Of these potential measures, the market maker obligation may be the most appropriate for the I-SEM, since it is the most compatible with an integrated single market for electricity in Europe, will aid transparency and can be easily enforced and monitored. The requirement for this applies equally to Option 3 and to Option 1. There may also be a requirement to continue Directed Contracts in the near term.

With respect to day-ahead liquidity under Option 1, a self-supply restriction on the dominant player is also an option. Alternatively, the dominant player can be required to sell and buy a minimum percentage of its requirements through the DAM, as some players in the GB market have elected to do. Power NI considers this measure is likely to be required under a voluntary DAM.

The consultation document highlights the potential for competition through interconnectors to weaken the market power of dominant players, once these are fully integrated into the market arrangements. This may be true, but only to the extent that there is not a concentration of Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs) amongst the dominant players in the I-SEM. Some form of maximum capacity holdings may be considered to mitigate this risk. This requirement may also be enhanced given that a number of the Irish players have a significant presence in the UK market and therefore may have the ability to exercise market power by virtue of their interconnected integration.

As stated above, given the characteristics of the Irish market, Power NI encourages the RAs to actively look at the suite of market power mitigation measures as a feature of the market design. The Baringa paper included in Appendix 2 works through the various market power options and timeframes in significantly greater detail. Power NI would welcome the RAs considering the findings and arguments presented.

Financeability and stability

The implementation of the SEM significantly increased the collateral requirements placed upon suppliers. Pool exposure accompanied by hedging activities has required suppliers to have in place high value letters of credit or cash deposits. This collateral requirement is a burden on suppliers, requires

financing, potentially acts as a barrier to entry and the associated costs ultimately appear in an end users bill.

Power NI believes that the I-SEM should look wherever possible to minimise the collateral requirements to a reasonable level. Participation in the market should be encouraged and the costs minimised.

Equally of concern to participants who trade in Sterling, is the currency exposure potentially created by some of the options. Mandatory participation in markets linked via Euphemia will likely settle in Euro. This creates currency risk, potential currency hedging requirements and further collateral requirements on Sterling participants. This is an asymmetrical risk placed on certain participants in an inequitable manner.

While it may not be immediately considered relevant to a supplier, the financeability and stability of generation in the market is an important consideration.

Energy provides one source of income for generators and together with ancillary services provision and any capacity payment, completes their revenue stream. To operate effectively, generation participants must be able to have clear, unambiguous financing signals which will support investment over the long term and provide entry and exit signals. Power NI is concerned that the RAs continue to consider the energy market largely in isolation. The work stream looking at the DS3 programme and the question of capacity must be considered in conjunction with the design of the energy market.

Power NI's concern is that failing to consider the three strands of generator income as a package, risks either an over payment (or double payment) to generation, which could be avoided, inefficient signals which could result in payment for capacity that is no longer required (due to a deficient exit signals), or price scarcity due to an inefficient entry signal.

Each of these scenarios would result in a higher cost outcome for customers and therefore Power NI would encourage the RAs to take a holistic view to the consideration of generator financeability across the energy, capacity and ancillary/ balancing services markets.

High Level Design Options

Following the publication of the 4 options contained within the Consultation Paper, Power NI has undertaken a comprehensive analysis; considering the evaluation criteria, the key influencing factors from a supplier and customers perspective, as well as considering the likely market outcomes of the design.

Power NI has sought to address the detailed questions posed by the RAs in Appendix 1. This section summarises the thinking, considerations and position.

Option 2 - Mandatory Ex-Post Pool for Net Volumes

Option 2 presents some issues which it would make it challenging to implement in a new market design.

This option is an untested net complex pool concept with no international precedent. It also appears practically complex and as such it would be difficult to envisage how it would work operationally.

The RAs qualitative assessment scored this option poorly and Power NI concurs with the RAs view.

Option 4 - Gross Pool – Net Settlement Market

Option 4 also presents some issues which it would make it challenging to implement in a new market design.

This option raised concerns over the Interconnectors' integration with an ex-post pool when they are traded and settled in the DAM. This has the appearance of being discriminatory against conventional generation, prioritising cross border flows over the efficient operation of the entire market. There are also questions as to whether this option could work without significant on-going modification.

Additionally when considering this option it is –

- Unclear whether limiting participation in DAM / IDM to financial trades is consistent with the spirit of the Target Model, and whether this option will deliver benefits to SEM from improved interconnector flows.
- There is uncertainty around participation in DAM / IDM given scheduling risk and potentially benign ex-post imbalance pricing (why would a participant trade ex-ante?)
- It dilutes the interconnector as an effective retail hedge as FTRs settle against DAM, but expect main reference price to be ex-post pool in this option.
- A voluntary DAM may favour parties with more certainty on their ex-post schedule position (inequitable for marginal or intermittent resources), and
- any move to incentivise participation in Forward / DAM / IDM by making the ex-post pool less attractive results in significant changes to current

SEM market design (uplift / CRM / SRMC BCoP) without the possible mitigating upsides provided by Options 1 and 3.

Finally, while Power NI accepts that this option could be argued as compliant, there would certainly be an element of doubt and therefore it is likely that this option would be refined further in the nearer term, undermining its qualitative assessment against the Internal Electricity Market, Stability and Practicality/Cost assessment criteria.

Option 3 - Mandatory Centralised Market

Option 3 aims to increase liquidity by focusing on the DAM which is beneficial for effective market coupling. This however does not secure liquidity in the forwards market, which is the overarching requirement of suppliers and customers. As described above, price stability and predictability are key mass market customer requirements which can only be met by an efficient forwards market.

Under Option 3, much akin to the SEM, generators will not know until close to real time if they will be in the merit order. As with today, such uncertainty tends to drive a lack of forward liquidity.

Power NI also has some reservations about EUPHEMIA acting as the market solver at a European level, removing an element of control of the Irish electricity market away from SEMO. Option 3 differs from the prevailing design in other European markets by relying exclusively on the Euphemia coupling algorithm to directly formulate day-ahead generation schedules. Most European power exchanges operate voluntary day-ahead markets with portfolio bidding arrangements.

There are parallels between this HLD option and the Iberian market, which has implemented Euphemia with unit-based bidding and support for sophisticated offer formats to help generators manage scheduling risks. However, participation in the Iberian DAM is voluntary, and generators there have the option to self-dispatch under physical bilateral contracts.

The mandatory DAM proposal is reliant on SEM generators being able to manage unit commitment with complex or sophisticated orders in Euphemia. To date, only the Iberian market has supported sophisticated orders, and the thermal plant utilising these order formats represent a much smaller proportion of the overall market than would be expected in the SEM. Other power exchanges have placed limitations on the size and number of complex orders in order to safeguard the performance of the coupling algorithm.

Thus, while the Euphemia algorithm certainly has the functionality to support a mandatory DAM in the I-SEM, there has been no clear evidence to date regarding the feasibility of this proposed approach. Rigorous testing would therefore be required to verify the performance of the algorithm in a relatively small market with a high proportion of large units using complex orders. Power NI

considers this a risk to the I-SEM implementation both in terms of establishment and outcome.

Given these potential risks and concerns with the mandatory DAM approach, it may be prudent for the I-SEM implementation programme to develop the processes to support a degree of bilateral trading outside the Euphemia platform. This would be consistent with the prevailing design in other European markets and provide a fall back mechanism, allowing SEM generators to self-dispatch in the event that the use of complex order formats proves unsatisfactory.

Baringa have provided Power NI with a report looking at the implementation of Euphemia across Europe. This report is provided in Appendix 3 for the RAs consideration.

Additionally under Option 3, with most of the trading focussing in on the DAM, there would be significant credit and cashflow implications for the day-to-day operation of a supply business. Credit would have to be placed to cover the extent that forward trades are possible. Credit would also be required to be posted with the market place for the entire supplier volume traded through the DAM. A supplier seeking to hedge whatever is possible in the forwards market would also be covering the same proportion again with the NEMO, plus the residual. This increases the participation cost for suppliers.

It is also likely that the DAM will settle significantly earlier than the current SEM and potentially in Euro. While this might offset some of the credit requirement, the working capital facilities required would be in excess of today's requirements, increasing the cost to suppliers and potentially creating a barrier to supplier entry.

This option also heightens the currency exposure a Sterling participant is likely to be exposed to. Such an exposure is likely to prompt a requirement to hedge currency which in turn requires additional supplier collateral and increases the cost of participation in the market.

Finally, as stated previously, when considering the theoretical aspects of the market design it would be incorrect to assume that by ensuring a strong day ahead price (such as via Option 3) that it would provide such a robust reference price that it will naturally encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market and suffers from a chronic lack of liquidity.

Option 1 – Adapted De-centralised

Option 1 provides some potential benefits to the Irish market which should be recognised; specifically within the contract market. Should generator participants be able to self-schedule, then providing forward contract liquidity will provide running certainty. This would stimulate the forwards market.

This type of market design is also common across Europe and provides the simplicity which is key to customer engagement.

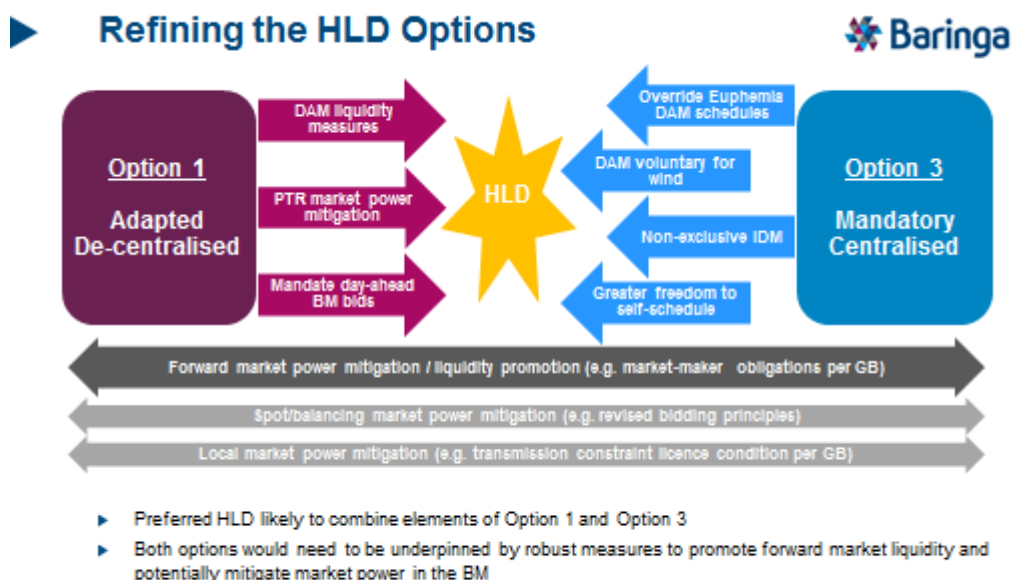
This option also mitigates the risk of the I-SEM relying on the Euphemia providing a feasible outcome in all situations.

Option 1 does suffer from potential market power issues; however Power NI considers all options suffer from the same issues. As explained above, the characteristics of the Irish market are such that market power mitigation should be an integral aspect of the market design. Market maker obligations and/or self-supply restrictions on certain players would ensure that the market operates effectively across all of the time frames. Such intervention would ensure that all participants; suppliers, thermal and renewable generators can operate effectively in the market.

Potential Solution

Power NI considers options 1 and 3 as being a continuum rather than competing options at opposite ends of a spectrum. Power NI believes beginning with Option 1 and including simple market power mitigation and some of the other aspects of Option 3 can offer the ideal outcome for the market across the timeframes.

The figure below attempts to pictorially describe what could provide the optimal market outcome.



With simple market power mitigation, liquidity could be secured in the forwards market as well as the DAM. The market could be afforded the freedom to actively trade with the market maker, independent generation and with lower cost renewable generation when available. The market maker obligations can provide a clear reference price with other thermal generation competing in the certainty that they will be physically firm if contracted. This creates an active forward market.

Trading over the interconnectors can be optimised by clear physical rights limited to particular volumes to ensure efficiency in later time frames. Physical positions secured in the forwards market can also be traded for lower cost generation in the DAM and IDT timeframes with both generators looking to trade their position for a lower cost one, and suppliers looking to refine short or long positions. Ensuring that the DAM is voluntary to wind may also alleviate some of the forecasting risk inherent with renewable generation.

This revised option effectively gives the RAs the ability to ensure that all market timescales are efficient and the optimal outcome is achieved. It also gives flexibility to adapt to future changes and does not rely upon theoretical drivers of behaviour.

Importantly this option can also minimise the credit requirements which participants are exposed to across the entire market horizon.

Capacity Remuneration Mechanism

Principles

As described in the Financeability Section, the current SEM CRM provides a significant income stream for generating participants. From a supplier perspective it is important to recognise that the current CRM does provide important investment signals for generation capacity provision while dampening energy price volatility in the SEM.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

It is difficult to envisage an argument that the original justification for a CRM in the SEM no longer applies. New capacity has entered the Irish market and the RAs Medium Term Review in 2011 concluded that the CRM remained important because of its impact on the financeability of generation.

CRMs are at the heart of the financeability assessment for generation participants and the need for an adequate total remuneration package was acknowledged as necessary by the RAs in the February 2013 Next Steps Decision Paper.

Power NI acknowledges that there are flaws with the current CRM scheme. There is a clear lack of distinct exit signals which could potentially be managed through a well-designed and consulted upon testing regime and the current scheme must be accompanied by appropriate ancillary service payments that encourage the required generation characteristics such as flexibility.

The need to encourage flexibility in generation is necessitated by the increasing levels of intermittent generation being connected to the Irish network and is therefore necessary to support the governmental renewable generation targets and their related EU commitments.

Within the Consultation Paper the RAs consider the 'energy only' market option. Power NI concurs with the RAs view that there would be significant challenges in ensuring adequate remuneration for capacity in an energy only market. These challenges include and are compounded by –

- the size of the market,
- market power and concentration issues,
- the inherent lack of long term price signals in an energy only market,
- the lack of stability,
- the absence of targeted flexibility needed for system security, and
- inherent price volatility without a dampening CRM.

Power NI therefore believes removing the CRM should not be considered as a viable option as given the above issues it would not be in the interests of consumers.

In balancing the benefits of a CRM and acknowledging the flaws, Power NI considers the I-SEM design phase as offering an opportunity to refine the CRM in order to continue providing the benefits of dampening of price volatility, a stable regulatory environment, investment signals and generator financeability; whilst targeting the flaw of a lack of exit signals and encouraging flexibility.

As an underlying principle any CRM implemented in the I-SEM should be consistent with efficient, economic interconnector flows and not act as a deciding factor in trading decisions.

EU Dynamic

The EU dynamic, particularly compliance with state aid guidelines, has raised concerns in relation to the on-going viability of a CRM. While it is important to ensure Ireland is compliant with such EU requirements, it is also important to recognise that there has been a discernible movement in view in relation to CRMs at a European level.

Power NI understands that there is a growing belief that it is possible to design a competitive market which contains both energy and capacity elements. Currently, the degree of intervention appears to be the main area of concern. Power NI believes that the RAs can robustly argue that a CRM in the I-SEM is an inherent design feature and is not adversely distorting the market. CRMs in other major European countries e.g. France and GB should provide assistance in this regard.

When considering CRMs therefore the argument is moving away from a question of legality toward an economic outcomes based consideration.

Options

In considering the CRM options as presented by the RAs, it is difficult to provide a substantive response without more detail and worked examples. It may be useful for the industry if the RAs and their consultancy support target workable solutions and conduct a detailed concurrent consultation exercise.

In general terms, a strategic reserve based approach appears to be a corrective action arising from a specific market failure rather than a feature of the market design. As acknowledged by the RAs it is not intended to provide long term investor certainty therefore its consideration in the Irish context is somewhat limited.

In relation to price based mechanisms, short term price signals will increase volatility and contain potential market power concerns whereas long term

improves stability and reduces volatility; however the RAs would need to consider how to enhance its targeting.

Solutions which create a supplier obligation suffer from difficulty in targeting, valuation and market power. It also philosophically seems unnecessary, when it is not competition between suppliers that is being sought per se, but selected necessary investment signals and price stability. Power NI recommends a solution which could be socialised across the market thereby reducing volatility, aiding transparency and avoiding unnecessary supplier participation costs.

In general terms, a level of intervention is not of particular concern as it should assist in the targeting of flexible generation assets; TSO procurement therefore appears appropriate.

Viridian Group commissioned a report from NERA in relation to a CRM. Power NI has included this in Appendix 4 for the RAs information and consideration.

Conclusion

In consideration of the key design aspects of the I-SEM, Power NI believes there are a number of fundamental principles and opportunities the RAs must consider.

Power NI has summarised these key, fundamentals as –

- The I-SEM project is under significant time pressure if it is to meet the 2016 deadline.
- The assessment criteria provide a useful basis for assessment.
- Establishing an effective, efficient and liquid forwards market is absolutely critical as this drives the ultimate price paid by the majority of consumers.
- The current SEM forwards market is not to be in the customers' interest and is failing due to market power and lack of generator certainty.
- The I-SEM offers an opportunity to improve the wholesale market in the interests of customers.
- Options 1 and 3 are a continuum rather than competing options at opposite ends of a spectrum.
- Option 1, including simple market power mitigation and some of the other aspects of Option 3 can offer the ideal outcome for the market across the timeframes.
- This option provides back stop generation certainty.
- Market power mitigation must be considered as a high level design consideration.
- Generator financeability is important and in the long term interests of the market and its customers.
- The current CRM does provide important investment signals for generation capacity provision while dampening energy price volatility.
- There are flaws with the current CRM scheme.
- The I-SEM design phase offers an opportunity to refine the CRM so as to continue to provide the benefits while targeting the flaws.

Next Steps

As stated in the introduction Power NI is concerned that the compressed timeframe available to the RAs to meet European compliance requirements may prompt design decisions to be taken in isolation and place pressure on due process.

Power NI strongly advocates that the RAs continue to closely engage with market participants at every stage of the design and decision stage. Regulatory Impact Assessments and a cost benefit analysis are important due process activities which should be completed.

Power NI would also welcome the RAs establishing a series of groups such as the 'Business Liaison Group' (BLG), 'Technical Liaison Groups' (TLG), Communication Forum and legal and procedural workstreams which were established in the run up to the completion of the SEM final design to assist in the engagement and communication process.

Appendix 1 – Consultation Paper Questions

Within this section Power NI has answered the specific questions posed by the RAs in the consultation paper. References are made to earlier comments where appropriate.

Purpose of the Document

Q1. *Which option for energy trading arrangements would be your preferred choice for the I-SEM market, and why?*

- Power NI believes that Option 1, including simple market power mitigation and some of the other aspects of Option 3 can offer the ideal outcome for the market across the timeframes. As described above, with tailored market power mitigation measures this could deliver the optimal outcome for all participants across the spectrum of market timeframes.

Q2. *Is there a requirement for a CRM in the revised HLD, and why?*

- Power NI believes that there is a requirement for a CRM in the revised HLD.

The current SEM Capacity Remuneration Mechanism (CRM) provides a significant income stream for generating participants. From a supplier perspective it is important to recognise that the current CRM does provide important investment signals for generation capacity provision while dampening energy price volatility in the SEM.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

It is difficult to envisage an argument that the original justification for a CRM in the SEM no longer applies. New capacity has entered the Irish market and the RAs Medium Term Review in 2011 concluded that the CRM remained important because of its impact on the financeability of generation.

CRMs are at the heart of the financeability assessment of generation participants and the need for an adequate total remuneration package was acknowledged as necessary by the RAs in the February 2013 Next Steps Decision Paper.

Q3. *If there is a requirement for a CRM in the revised HLD, what form would be your preferred choice for the I-SEM, and why?*

- In considering the CRM options as presented by the RAs, it is difficult to provide a substantive response without more detail and worked examples. It may be useful for the industry if the RAs and their

consultancy support target workable solutions and conduct a detailed concurrent consultation exercise.

In general terms, Power NI can see advantages in a long term price based mechanism as such a CRM would provide stable signals for generation investment while avoiding short term volatility which is not in the interests of the majority of consumers.

Topics for the High Level Design of Energy Trading Arrangements

Q4. Are these the most important topics to consider in the description of the HLD for the revised energy trading arrangements for the single electricity market on the island of Ireland?

- The RAs have identified the majority of the topics which should be considered when reviewing the HLD of the I-SEM.

Power NI does believe however that market power mitigation was not effectively considered in the design of the SEM with Directed Contracts being mandated relatively late in the process and no consideration was given to the forwards market and whether it would operate effectively.

To fail to consider this issue in the design phase of the I-SEM repeats a fundamental SEM design flaw which has pushed scarcity premiums to end consumers.

Power NI is also concerned that the RAs continue to consider the energy market largely in isolation. The work stream looking at the DS3 programme and the question of capacity must be considered in conjunction with the design of the energy market.

Power NI's concern is that failing to consider the three strands of generator income as a package, risks either an over payment (or double payment) to generation which could be avoided, inefficient signals which could result in payment for capacity that is no longer required (due to a deficient exit signals), or price scarcity due to an inefficient entry signal.

Each of these scenarios would result in a higher cost outcome for customers and therefore Power NI would encourage the RAs to take a holistic view to the consideration of generator income and financeability across the energy, capacity and ancillary/balancing services markets.

Summary of the Options for Energy Trading Arrangements

Q5. *Are there other aspects of the European Internal Electricity Market that should form part of the process of the High Level Design of energy trading arrangements in the I-SEM?*

- As far as Power NI is aware, the RAs have considered all the aspects of the European Internal Electricity Market requirements.

Q6. *What evidence can you provide for the assessment of the HLD options with respect to security of supply, efficiency, and adaptability?*

- Power NI concurs with the RAs assessments that the security of supply requirement will be met by the actions of the TSOs, however it is important to recognise that the TSOs can only dispatch plant which is available to them. Security of supply therefore should consider the financeability, stability and entry/exit signals given to generation participants.

Efficiency is an important consideration in terms of outcomes and specifically how those outcomes impact customers. As a supplier delivering products to end consumers these criteria are vital.

Power NI has assessed each option against the criteria and embedded their view in the answers below.

Adapted Decentralised Market

Q7. *Are there any changes you would suggest to make the Adapted Decentralised Market more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?*

- Power NI believes that additional measures will likely be needed to mitigate market power thereby ensuring the effectiveness, liquidity and reliability of price setting in the forward market.

The measures that could be used to encourage forward market liquidity include:

- Directed Contracts, as under the current SEM.
- Market maker obligations on certain players, as required by Ofgem in GB under its 'Secure and Promote' proposals and suggested under Option 1 in the I-SEM consultation document.
- Self-supply restrictions on certain players.

The advantage of Directed Contracts is that they provide suppliers certainty of price against which they can set their retail tariffs and are familiar to current SEM participants. However, they do not provide any liquidity benefit to independent generators and require the RAs to take a direct role in setting wholesale prices, which ultimately is not part of the vision for the Electricity Target Model.

The market maker obligations should require the dominant player to make a minimum volume available in the forward market on both the buy and sell side within a maximum specified bid-offer spread. This provides liquidity to all market players, not just suppliers. These obligations should help to underpin the development of the forward market, without directly intervening in forward price levels and are similar to obligations mandated in other European countries.

Self-supply restrictions can also stimulate forward liquidity without directly intervening on price, but do not guarantee liquidity to the same extent as market maker obligations. They can also be harder to enforce although may be useful in the portfolio of market power mitigation.



















Of these potential measures, the market maker obligation may be the most appropriate for the I-SEM, since it is the most compatible with an integrated single market for electricity in Europe, will aid transparency and can be easily enforced and monitored. The requirement for this applies equally to Option 3 and to Option 1. There may also be a requirement to continue Directed Contracts in the near term.

With respect to day-ahead liquidity under Option 1, a self-supply restriction on the dominant player is also an option. Alternatively, the dominant player can be required to sell and buy a minimum percentage of its requirements through the DAM, as some players in the GB market have elected to do. Power NI considers this measure is likely to be required under a voluntary DAM.

Q8. Do you agree with the qualitative assessment of the Adapted Decentralised Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

- Power NI has taken the summary assessment and comments in relation to the Adapted Decentralised Market detailed by the RA's in Section 6.4 (Table 5) of the Consultation Paper and provided an alternative assessment as follows:

Possible Strength 
 Neutral 
 Possible Weakness 



















	RA's View		Power NI's View
SoS		Can be delivered by this option	
Stability		Depends on regulatory intervention needed to deliver liquid DAM and IDM	
Efficiency		Can be delivered by this option	
Practicality		Not a particular strength or weakness of this option	
Equity		If liquid, DAM and IDM provide some routes to markets, with more cost targeting	
Competition		Depends on effectiveness of competition from greater choice of trading strategies	
Environment		Wind exposed to imbalance prices, which can be managed if liquid IDM	
Adaptive		Governance processes to be determined during detailed design phase	
IEM		Liquidity promoting measures should facilitate efficient DAM flows	

Power NI would propose in terms of the equity criteria that this would be of little difference compared to the current market conditions leading to, at worst, a neutral outcome.

In relation to the competition criteria, it could be potentially changed to a complete green (possible strength) assessment given effective market maker obligations on larger market players. The market maker obligations would produce potential volume and liquidity in the forwards market, could facilitate efficient day ahead flows and reduce the possible weaknesses in the IEM criteria.

Additionally, the efficient forwards market could reduce the scarcity premium currently experienced in the SEM and paid for by consumers. This would increase the efficiency assessment.

Power NI refined its assessment assuming effective market power mitigation measures were in place and this led to a updated position as follows:

	RA's View		Power NI's View*
SoS		Can be delivered by this option	
Stability		Depends on regulatory intervention needed to deliver liquid DAM and IDM	
Efficiency		Can be delivered by this option	
Practicality		Not a particular strength or weakness of this option	
Equity		If liquid, DAM and IDM provide some routes to markets, with more cost targeting	
Competition		Depends on effectiveness of competition from greater choice of trading strategies	
Environment		Wind exposed to imbalance prices, which can be managed if liquid IDM	
Adaptive		Governance processes to be determined during detailed design phase	
IEM		Liquidity promoting measures should facilitate efficient DAM flows	
*With effective Market Power Mitigation measures			

Q9. How does the Adapted Decentralised Market measure against the SEM Committee's primary duty to protect the long and short term interests of consumers on the island of Ireland?

- Option 1 as described in the Consultation Paper offers the potential of an effective forwards market developing. As described earlier in this response the ultimate cost to consumers, especially domestic and small/medium sized commercial customers, is directly related to the effectiveness or lack of effectiveness of the forwards market.

With effective market power mitigation, and the certainty offered by physically firm forward trades, this option (utilising aspects of Option 3) has the potential to ensure an effective forwards market develops.

Power NI believes that should the RAs deliver such an effective forwards market then they will have acted in line with their statutory duties to protect consumers.

Mandatory Ex-Post Pool for Net Volumes

Q10. *Are there any changes you would suggest to make the Mandatory Ex-post Pool for Net Volumes more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?*

- Power NI shares the concerns reflected in the RA's own assessment in relation to the Mandatory Ex-Post Pool for Net Volumes. Such are the extent of the weaknesses identified with this option, Power NI believes it should now be removed from consideration.

Q11. *Do you agree with the qualitative assessment of Mandatory Ex-post Pool for Net Volumes against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?*

- Power NI has reviewed the summary assessment of the Mandatory Ex-Post Pool for Net Volumes detailed by the RA's in Section 7.4 (Table 6) and provided its assessment as follows:

	RA's View		Power NI's View
SoS		Can be delivered by this option	
Stability		Difficult to manage balance between pool and European markets	
Efficiency		Can be delivered by this option	
Practicality		Depends on balance of physical trading between pool and European markets	
Equity		Liquidity may be split between pool and European markets	
Competition		Depends on balance of physical trading between pool and European markets	
Environment		Depends on balance of physical trading between pool and European markets	
Adaptive		Not a particular strength or weakness of this option	
IEM		Net pool not fit neatly into either a balancing market, or fully integrated dispatch	

Power NI agrees with the RA's assessment of the option. As suggested by the assessment table, there is an increased level of risk and potential for weaknesses in the market design to the extent that this option should not be pursued.

Q12. How does the Mandatory Ex-post Pool for Net Volumes measure against the SEM Committee's primary duty to protect the long and short term interests of consumers on the island of Ireland?

- As described earlier in this response, the ultimate cost to consumers, especially domestic and small/medium sized commercial customers, is directly related to the effectiveness or lack of effectiveness of the forwards market. Power NI does not believe that this option will deliver an efficient, effective forwards market and therefore is not consistent with the RAs statutory duty to protect consumers.

Mandatory Centralised Market

Q13. Are there any changes you would suggest to make the Mandatory Centralised Market more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?
























- As stated previously, Power NI sees a continuum between the Adapted Decentralised Market and the Mandatory Centralised Market designs as being a more effective proposal for the market than one isolated option.

Power NI believes that Option 1, including simple market power mitigation and some of the other aspects of Option 3 can offer the ideal outcome for the market across the timeframes.

Q14. Do you agree with the qualitative assessment of Mandatory Centralised Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

- Power NI has taken the summary assessment of the Mandatory Centralised Market detailed by the RA's in Section 8.4 (Table 7) and provided a counter assessment as follows:

Possible Strength	
Neutral	
Possible Weakness	

	RA's View		Power NI's View
SoS		Can be delivered by this option	
Stability		Depends on regulatory intervention needed to enforce DAM and IDM rules	 
Efficiency		Can be delivered by this option	 
Practicality		Not a particular strength or weakness of this option	
Equity		DAM and IDM provide route to markets, with more targeting of costs	 
Competition		Could be strong within 'approved' market places, with high transparency	 
Environment		Wind exposed to imbalance prices, which can be managed in liquid IDM	 
Adaptive		Not a particular strength or weakness of this option	
IEM		Compliant with requirements, with DAM/IDM supporting effective flows	

Power NI considers Option 3 to have more weaknesses that the RA's assessment would suggest. Power NI believes that focusing liquidity in the DAM will not inherently deliver an efficient forwards market and therefore the efficiency, equity (due to scarcity premiums) and competition (due to the experience of participation in the current forwards market) assessment criteria are not necessarily enhanced. These potential weaknesses are not reflected in the RAs assessment.

Q15. How does the Mandatory Centralised Market measure against the SEM Committee's primary duty to protect the long and short term interests of consumers on the island of Ireland?

- As described earlier in this response the ultimate cost to consumers, especially domestic and small/medium sized commercial customers, is directly related to the effectiveness or lack of effectiveness of the forwards market. It would be incorrect to assume that ensuring a strong day ahead price would provide such a robust reference price that it will naturally encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however suffers from a chronic lack of liquidity.

This option does not deal with the inhibiting factors of generator uncertainty and market power which adversely impact the forwards market. Dealing with these issues (as described in the Potential Solution) would enhance the effectiveness of the forwards market and therefore ensure that the RAs meet their statutory duty in relation to the protection of consumers.



















Gross Pool – Net Settlement Market

Q16. *Are there any changes you would suggest to make the Gross Pool – Net Settlement Market more effective for the all I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?*

- Power NI acknowledges the widely held viewpoint that this option represents least movement from the current market design and conditions.

Q17. *Do you agree with the qualitative assessment of Gross Pool – Net Settlement Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?*

- Power NI has taken the summary assessment of the Gross Pool – Net Settlement Market detailed by the RA's in Section 9.4 (Table 8) and provided its assessment as follows:

	RA's View		Power NI's View
SoS		Can be delivered by this option	
Stability		Limited change from current arrangements	
Efficiency		Can be delivered by this option	
Practicality		Not a particular strength or weakness of this option	
Equity		Pool provides route to markets, with greater targeting of costs and benefits	
Competition		Strong regulation of market participant behaviour	
Environment		Ex-post pool attractive for wind, but may need additional incentives for flexibility	
Adaptive		Not a particular strength or weakness of this option	
IEM		Compliant with requirements, but more unfamiliar model in European context	

Power NI envisages more issues with this Option than the RA's. While it is agreed that the market design will be adaptive and have the ability to change, it is likely that this design will require significant on going changes to remain effective and compliant. This undermines the assessment of stability and efficiency. Additionally a cost premium on a poor forwards market in this scenario will have a detrimental effect on equity and competition.

Q18. *How does the Gross Pool – Net Settlement Market measure against the SEM Committee's primary duty to protect the long and short term interests of consumers on the island of Ireland?*

- As described earlier in this response the ultimate cost to consumers, especially domestic and small/medium sized commercial customers, is directly related to the effectiveness or lack of effectiveness of the forwards

market. It would be incorrect to assume that by ensuring a strong day ahead price would provide such a robust reference price that it will naturally encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however suffers from a chronic lack of liquidity.

Within the inherent design features of this option it is difficult to envisage how the RAs could deal with the inhibiting factors affecting the forwards market. Mindful of this, this option does little to protect consumers.

Capacity Remuneration Mechanisms

Q19. *What are the rationales for and against the continuation of some form of CRM as part of the revised trading arrangements for the I- SEM?*

- As stated above the current SEM Capacity Remuneration Mechanism (CRM) provides a significant income stream for generating participants. From a supplier perspective it is important to recognise that the current CRM does provide important investment signals for generation capacity provision while dampening energy price volatility in the SEM.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

It is difficult to envisage an argument that the original justification for a CRM in the SEM no longer applies. New capacity has entered the Irish market and the RAs Medium Term Review in 2011 concluded that the CRM remained important because of its impact on the financeability of generation.

CRMs go to the heart of the financeability assessment of generation participants and the need for an adequate total remuneration package was acknowledged as necessary by the RAs in the Feb 2013 Next Steps Decision Paper.

Power NI acknowledges that there are flaws with the current CRM scheme. There is a clear lack of distinct exit signals which could potentially be managed through a well-designed and consulted upon testing regime and the current scheme must be accompanied by appropriate ancillary service payments that encourage the required generation characteristics such as flexibility.

In balancing the benefits of a CRM and acknowledging the flaws; Power NI considers the I-SEM design phase as offering an opportunity to refine the CRM so as to continue to provide the benefits of investment signals, dampening of price volatility and generator financeability while targeting the flaws of double payments, a lack of exit signals and no flexibility targeting.

The alternative to a CRM would be a reliance on financeability and investment signals being provided in an 'energy only' market. Power NI believes that this approach would suffer from significant challenges in ensuring adequate remuneration for capacity. Additionally it would expose consumers to significant price volatility and ultimately, if the signals were not sufficiently robust (as would likely be the case), result in a generation shortage requiring remedial future high cost, high risk intervention.

Q20. *Are these the most important topics for describing the high level design of any future CRM for the I-SEM?*

- Power NI has no further comment at this time.

Strategic Reserve

Q21. *Are there any changes you would suggest to make the design of a Strategic Reserve mechanism more effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- In general terms, a strategic reserve based approach appears to be a corrective action arising from a specific market failure rather than a feature of the market design. As acknowledged by the RAs it is not intended to provide long term investor certainty therefore its consideration in the Irish context is somewhat limited.

Q22. *Do you agree with the initial assessment of the strengths and weaknesses of a Strategic Reserve Mechanism? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- Power NI considers that the RAs have identified the weaknesses with a Strategic Reserve Mechanism.

Q23. *Would a Strategic Reserve Mechanism work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Long-Term Price-Based CRM

Q24. *Are there any changes you would suggest to make the design of a Long-term price-based CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Power NI believes without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question. In general terms however; long term price CRMs do improve stability and reduce volatility, although the RAs would need to consider how to enhance its targeting.

Q25. *Do you agree with the initial assessment of the strengths and weaknesses of a Long-term price-based CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Q26. *Would a Long-term price-based CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Short-Term Price-Based CRM

Q27. *Are there any changes you would suggest to make the design of a Short-term price-based CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Power NI believes without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question. In general terms however; short term price CRMs will increase volatility and contain potential market power concerns.

Q28. *Do you agree with the initial assessment of the strengths and weaknesses of a Short-term price-based CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question however as noted above a short term price CRM will increase volatility.

Q29. *Would a Short-term price-based CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Quantity-Based Capacity Auction

Q30. *Are there any changes you would suggest to make the design of a Quantity-based Capacity Auction CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Q31. *Do you agree with the initial assessment of the strengths and weaknesses of a Quantity-based Capacity Auction CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- While this solution would provide long term price signals and transparency for investment it is less effective in securing flexible capacity.

Q32. *Would a Quantity-based Capacity Auction CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Quantity-Based Capacity Obligation

Q33. *Are there any changes you would suggest to make the design of a Quantity-based Capacity Obligation CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Q34. *Do you agree with the initial assessment of the strengths and weaknesses of a Quantity-based Capacity Obligation CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- As stated above, solutions which create a supplier obligation suffer from difficulty in targeting, valuation and market power. It also seems philosophically unnecessary, when it is not competition between suppliers that is being sought per se, but selected necessary investment signals and price stability. For these reasons, Power NI consider this option as inappropriate for the Irish market.

Q35. *Would a Quantity-based Capacity Obligation CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Centralised Reliability Options

Q36. *Are there any changes you would suggest to make the design of a Centralised Reliability Option CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Without further details in relation to the operation of such a mechanism Power NI is unable to substantively respond to this question.

Q37. *Do you agree with the initial assessment of the strengths and weaknesses of a Centralised Reliability Option? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- Without further details in relation to the operation of such a mechanism Power NI is unable to substantively respond to this question.

Q38. *Would a Centralised Reliability Option work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Decentralised Reliability Options

Q39. *Are there any changes you would suggest to make the design of a Decentralised Reliability Option CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?*

- Without further details in relation to the operation of such a mechanism Power NI is unable to substantively respond to this question.

Q40. *Do you agree with the initial assessment of the strengths and weaknesses of a Decentralised Reliability Option? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?*

- Without further details in relation to the operation of such a mechanism Power NI is unable to substantively respond to this question.

Q41. *Would a Decentralised Reliability Option work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?*

- Without further detailed explanation of the operation of such a mechanism it is difficult to address this particular question.

Appendix 2 – Baringa Report entitled “Promoting forward liquidity and mitigating market power in the I-SEM”

▶ **I-SEM HLD Consultation:
Promoting forward liquidity and mitigating
market power in the I-SEM**

CLIENT: Viridian
DATE: 06/04/2014

V4.0

Version History

Version	Date	Description	Prepared by	Approved by
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1. INTRODUCTION

Liquid forward, day-ahead and within-day markets are essential components of well-functioning electricity markets. They stimulate competition by allowing parties to manage risk, offer stable prices to their customers and support new investments. Therefore, a key consideration for the I-SEM design is how liquidity will be promoted in each of these trading time horizons.

In this paper we focus on liquidity considerations for two of the four HLD options described in the I-SEM consultation document¹, namely Option 1 ('Adapted Decentralised Market') and Option 3 ('Mandatory Centralised Market'). In our view, these represent the most feasible options for the I-SEM high-level design. The other two options which retain elements of an ex-post pool we believe are unnecessarily complex and are unlikely fully to realise the benefits of market coupling under the European Target Model.

We consider what the implications of each option may be for market liquidity, and what additional measures may be required to stimulate liquidity further. Although the Regulatory Authorities (RAs) indicated in the consultation document that they did not want the choice of HLD option to be determined by considerations relating to market power, we also touch on the broader market power mitigation measures likely to be necessary under either option.

¹ I-SEM High Level Design for Ireland and Northern Ireland from 2016, Consultation Paper, 5 February 2014, SEM-14-008

2. PROMOTING FORWARD MARKET LIQUIDITY

2.1. The Importance of forward markets

The majority of customers, domestic, small and medium sized enterprises (SME) and to a lesser extent Large Electricity Users (LEUs), require energy tariffs with price certainty to insulate themselves from volatility in wholesale energy markets. Suppliers aim to meet this demand for fixed or low volatility tariffs by hedging through forward markets.

Liquid and transparent forward markets enable suppliers to hedge efficiently, shield consumers from volatile spot markets and offer consumers the most competitive tariff structures. Forward markets also provide open access to mitigate market power and concentration, and generate price signals to drive investment. Effective functioning of forward markets is therefore essential for competition and consumer choice.

2.2. What is liquidity?

Liquidity is the ability to contract with confidence for a product to meet volume commitments, at a fair market price, without causing undue change in the market pricing level or cost of transacting. Liquidity therefore provides participants with the following attributes to enable competitive pricing and effective market functioning:

- ▶ Confidence that they can contract forward at reasonable pricing levels, allowing them to offer fixed price tariffs and contracts to their customers;
- ▶ Ability to hedge earnings risk on their generation assets;
- ▶ The ability to manage the 'shape' of their portfolios through sufficient access to granular products (particularly in near term markets);
- ▶ Reliable reference prices for settling financial contracts and low carbon support agreements (such as REFIT and CfDs);
- ▶ Effective price signals for operational decisions; and
- ▶ Reliable price signals for new investment decisions.

The importance of maintaining liquidity for effective market functioning can be observed through the various interventions by regulators in the GB day ahead and forward power markets. (This is discussed further in Section 2.6 below). It should also be noted that liquidity can vary at different points in the trading time horizon. For example, in European electricity markets, day-ahead liquidity is typically greater than that within-day and often exceeds that in forward timescales.

2.3. Key indicators of market liquidity

Two key indicators of market liquidity are the volumes transacted in a market and the bid-offer spreads.

Figure 2.1 illustrates liquidity in the day-ahead markets in four European electricity markets, by showing historic monthly traded volumes as a percentage of monthly market demand. The graph illustrates that the German markets have typically engaged good levels of liquidity on exchanges at the day-ahead stage. Before 2013, the GB market

had very low levels of day-ahead liquidity on exchanges, but this dynamic changed significantly in 2012 when several large participants started to trade large volumes through the day-ahead market as part of the gross bidding commitment. We explore the reasons behind this further in Section 2.6.

Figure 2-1 European day-ahead exchange volume²

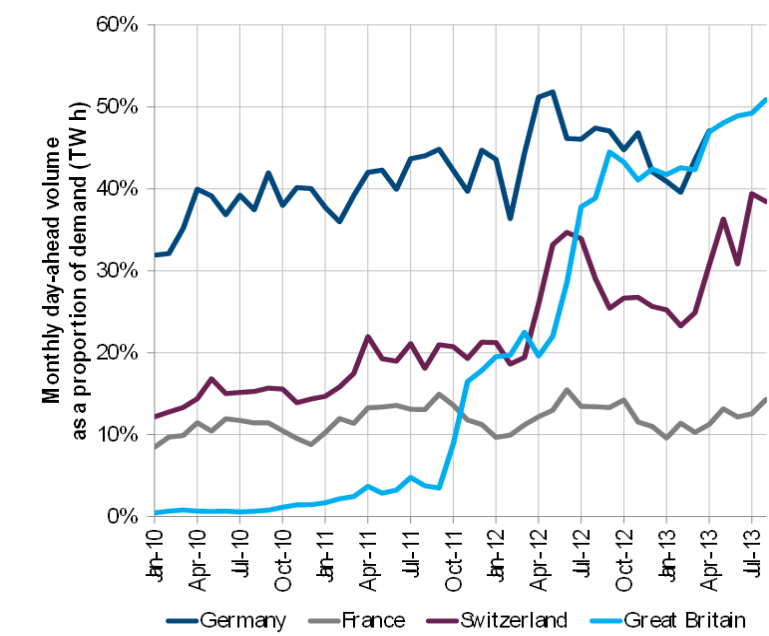
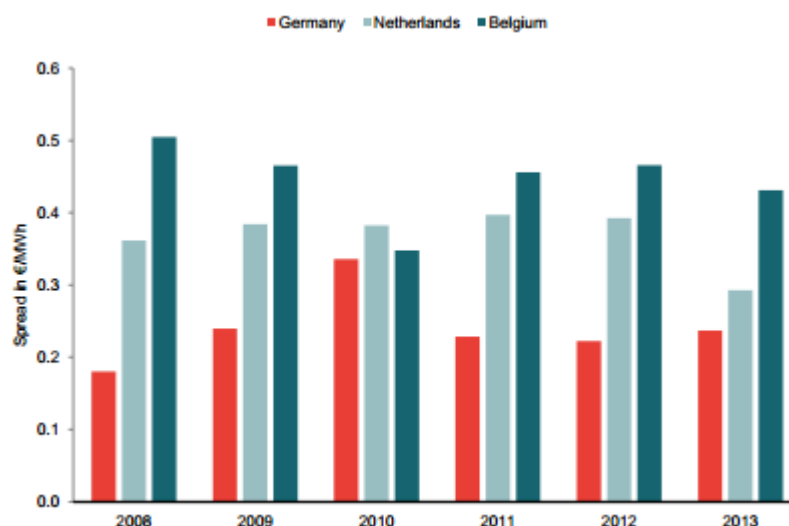


Figure 2.2 below shows the yearly average bid-offer spreads for year ahead products in the OTC forward markets for three European markets. Tight bid-offer spreads, combined with high trade volumes are indicative of liquidity. The tight bid-offer spreads and robust trade volumes in the German market would indicate the presence of liquidity.

² Source: EPEX Spot, N2EX

Figure 2-2 OTC bid-offer spreads for 1-year products³



Another important indicator of liquidity is the pricing level of contracts. A convergence of pricing levels across exchanges or broker platforms tends to indicate the presence of liquidity and re-assurance that prices are cost-reflective.

2.4. Issues with forward market liquidity in the SEM

We have carried out an assessment of the liquidity indicators in the SEM forward market and identified a number of issues with market liquidity. In review, the analysis has concentrated on the Non-Directed Contract (NDC) forward contract market in the SEM as administered through an auction and OTC trading platform run by Tullett Prebon. Recent trends indicate there has been a move away from the auction format towards trading through the OTC platform. The analysis presented in this paper is based upon published, publicly available, information gathered from Tullett Prebon and focuses on forward power contracts sold via the Tullett Prebon platforms for the calendar year 2013.⁴

2.4.1. Market concentration

Whilst there are a relatively large number of generators in the SEM, ESB holds a dominant position and is able to maintain market share in the ex-post pool due to its large and fuel diverse generation portfolio. This provides ESB with potential opportunities to exert market power, and thereby reduce competition, in both forward and spot market timeframes. ESB's dominance can be observed below in Figure 2.3 which provides an illustration of market share by percentage of the total MSQ generation output in 2013.

³ Source: Spectron, Frontier Economics

⁴ Tullett Prebon OTC trading results as published 3-April 2014

Figure 2-3 Generation market share by company as % of total MSQ generation⁵ output in 2013.⁶

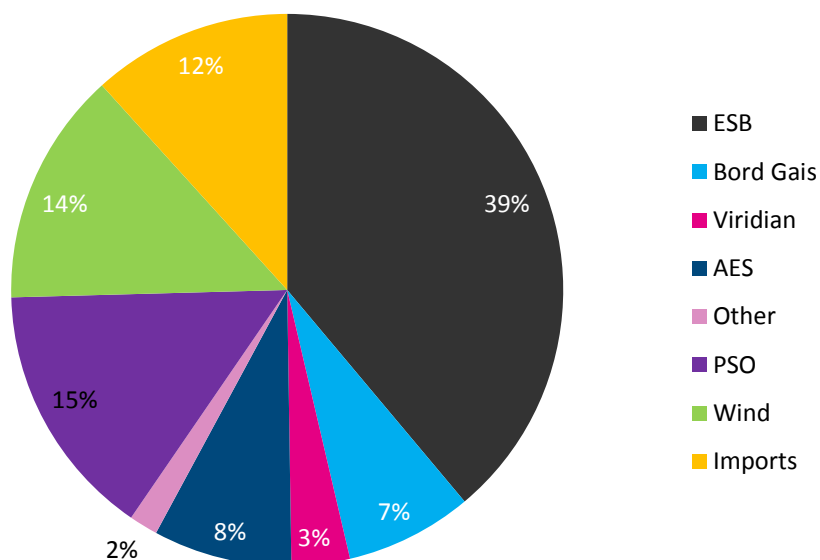


Figure 2-4 Supply market share⁷ by company as % of total consumption (MWh) in 2013⁸

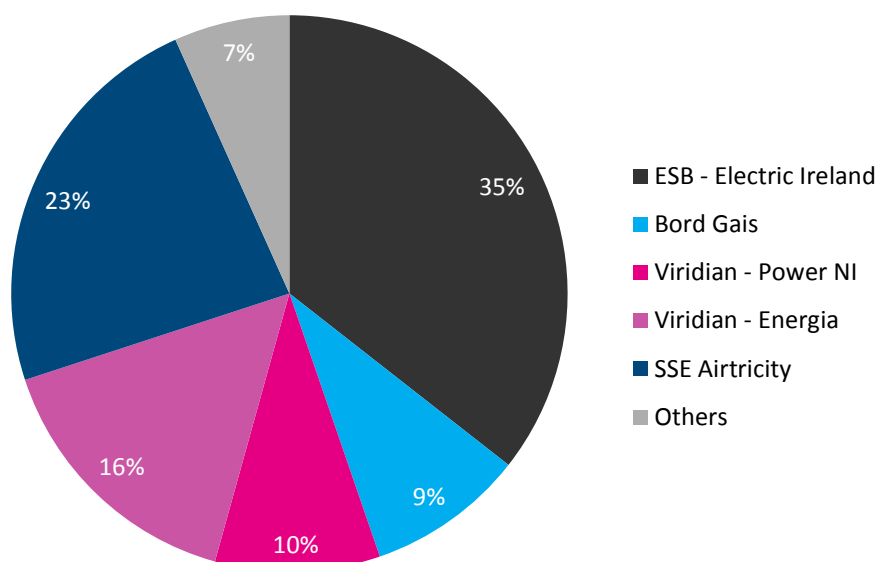


Figure 2.4 displays the share of the supply market by company as a percentage of consumption in 2013. Comparison of Figures 2.3 and 2.4 illustrates that ESB generation

⁵ Due to its variability, wind is not envisaged to be sold in the forward markets, and hence has not been split by owner / PPA holder. PSO plant is grouped together, as opposed to by owner, as forecast PSO output is sold through PSO specific trading windows.

⁶ Source: SEMO

⁷ Market share for NI calculated for year to 31 December 2013, for ROI calculated for year to 30 September 2013

⁸ Source: Utility Regulator NI, CER

and supply shares are broadly equal, with a net position that is slightly long generation (noting that ESB also controls a proportion of the wind and PSO generation in the pie chart). By contrast, both Viridian and SSE Airtricity have a long supply / short generation portfolio. Market players with a long supply / short generation portfolio will be more reliant on a forward market to effectively contract and hedge their retail positions.

2.4.2. Infrequency of forward trading opportunities in the SEM

The SEM OTC forward market generally only provides participants with the opportunity to trade twice per calendar month, supplemented by ad-hoc NDC auctions with timings and volumes determined by the sellers. This leads to infrequent market activity with no set timelines for trading opportunities. This level of market access should be contrasted to other European forward power markets which trade on all business days throughout the calendar year. Overall, the infrequency of trading ‘windows’ for forward contracts restricts opportunities for SEM participants to engage in the forward market and acts as barrier to market liquidity.

2.4.3. SEM forward market trade volumes

A lack of traded volume in a market indicates either a lack of participation by supply or demand, or an unwillingness to transact at the pricing level of the market. Table 2.1 below displays the volume for all contracts traded in 2013 in the SEM DC, NDC and PSO forward contract market. The trade volumes have also been given as a percentage of the annual consumption in 2013, and split out by DC (Directed Contract), NDC and PSO. To provide a useful comparison, the table includes equivalent data from the more liquid German forward market. This comparison indicates that both in terms of traded volumes, and the volumes as a percentage of demand, the SEM is significantly lower than the German forward power market, indicating a lack of liquidity in the SEM.

Table 2-1 Forward traded volumes relative to annual demand volume in 2013⁹

Combined SEM DC, NDC and PSO trade volume (GWh)	Combined SEM trade volume as a % of annual demand	SEM DC trade volume as a % of annual demand	SEM NDC ¹⁰ trade volume as a % of annual demand	SEM PSO trade volume as a % of annual demand	German Phelix Futures ¹¹ Volume (GWh)	German Phelix trade volume as a % of annual demand
11843	33.43%	11.47%	16.09%	5.87%	1,206,446	240.07%

Analysis also indicates a significant proportion of generation volume in the SEM is not placed on the forward markets for trading opportunities. Review of the SEM trading volumes shows the dominant player, ESB, selling approximately 8.0TWh¹² for delivery in 2013 compared to a generation MSQ of 13.8TWh, implying less than 60% of its generation volume goes through the forward markets. This is illustrative of the potential extra volume that could go through the forward markets to improve liquidity if appropriate regulatory measures were in place.

⁹ Source: EEX, Tullett Prebon, All-Island Generation Capacity Statement.

¹⁰ NDC numbers include Tullett Prebon OTC market, ESB NDC, PPB NDC and AES NDC.

¹¹ German Phelix Futures includes only volumes traded on EEX exchange and is not inclusive of any OTC trading.

¹² Calculated from sum of DC, ESB NDC and estimated share of NDC OTC.

2.4.4. SEM forward market bid-offer spreads

Tables 2.2 and 2.3 below display the spread between the forward market close bid and offer prices for the SEM and other European markets. Table 2.2 displays the spread as a percentage of the bid price, and Table 2.3 illustrates the spread in €/MWh terms. Analysis of the data demonstrates that the SEM has extremely wide bid-offer spreads when compared to other European forward electricity markets. The combination of low traded volumes and large bid-offer spreads in the SEM NDC OTC market is indicative of low levels of liquidity and will lead to high transaction costs for participants and therefore higher retail costs for customers.

Table 2-2 Market close bid-offer spreads as % of the market close bid price across SEM and European power markets¹³

Trade date	Curve	Spread as % of bid price				
		SEM ¹⁴	GB	Germany	Belgium	Holland
22 January 2014	Front month	6.0%	2.0%	0.8%	1.0%	1.0%
	Front quarter	7.9%	2.1%	0.9%	3.4%	1.1%
13 November 2013	Front month	5.6%	1.8%	0.8%	0.8%	1.0%
	Front quarter	13.9%	1.8%	0.7%	3.8%	0.9%
24 July 2013	Front month	9.0%	2.1%	0.8%	1.4%	1.1%
	Front quarter	12.6%	1.9%	0.8%	4.2%	1.0%
08 May 2013	Front month	5.7%	2.1%	0.9%	4.5%	1.0%
	Front quarter	4.5%	2.1%	0.9%	1.3%	2.1%
20 February 2013	Front month	3.8%	2.1%	0.8%	1.1%	1.1%
	Front quarter	5.0%	2.0%	0.8%	1.2%	1.1%

Table 2-3 Market close bid-offer spreads in €/MWh across SEM and European power markets¹⁵

Trade date	Curve	Spread (€/MWh)				
		SEM ¹⁶	GB	Germany	Belgium	Holland
22 January 2014	Front month	4.00	1.21	0.30	0.50	0.50
	Front quarter	5.00	1.22	0.30	1.30	0.50
13 November 2013	Front month	4.00	1.19	0.30	0.45	0.50
	Front quarter	9.02	1.19	0.30	2.00	0.50
24 July 2013	Front month	5.50	1.17	0.30	0.50	0.50
	Front quarter	7.80	1.16	0.30	2.00	0.50
08 May 2013	Front month	3.30	1.18	0.30	2.00	0.50
	Front quarter	2.68	1.19	0.30	0.50	1.00
20 February 2013	Front month	2.40	1.16	0.30	0.50	0.50
	Front quarter	2.94	1.15	0.30	0.50	0.50

2.4.5. DC and NDC pricing levels

Table 2.4 shows the weighted average NDC premia paid on trades executed through the Tullett Prebon OTC market in 2013 to the corresponding DC price¹⁷. Analysis indicates

¹³ Source: Platts, Tullett Prebon

¹⁴ SEM NDC OTC as traded through the Tullett Prebon OTC platform

¹⁵ Source: Platts, Tullett Prebon

¹⁶ SEM NDC OTC as traded through the Tullett Prebon OTC platform

that the NDC products are pricing on average up to 6.8 €/MWh more than comparative DC products, as illustrated in table 2.4 below¹⁸. This represents a significant premium, and is indicative of a lack of competition in the SEM forward market.

Table 2-4 Weighted average NDC premia over implied DC¹⁹

	Baseload	Mid-Merit	Peak	All products ²⁰
NDC OTC premia (€/MWh)	2.01	4.01	6.81	2.48

The table is also illustrative of the fact that whilst DCs can be used to mitigate forward market power, the small volumes sold (c3.5TWh) relative to total system demand (c35TWh) mean they have limited effect on NDC pricing.

2.4.6. Lack of transparency

Transparent forward markets ensure participants have a level playing field and facilitate price formation. The combined factors of scheduling risk for generators, infrequent trading opportunities, low traded volumes and market power concentration in the SEM forward market leads to an overall lack of transparency. The overall low levels of activity in the SEM forward market also mean that the market does not attract coverage from daily market and media reports reinforcing the problem.

2.5. Exertion of market power in the SEM forward market

Historical data and analysis as outlined above indicate a number of issues that restrict liquidity and competition in the SEM forward market. Indicators of restricted liquidity include low trading volumes, wide bid-offer spreads, infrequent trading opportunities and the NDC premia over the DC price. These issues could be regarded as being consistent with the presence of a dominant player with limited incentives to trade in the forward market, to the detriment of competitive pricing and consumer choice.

2.6. Liquidity measures in GB market

In considering options to improve liquidity in the SEM it is useful to review the measures undertaken recently by the regulator and market players to address liquidity concerns in the GB day ahead, and forward markets.

2.6.1. Gross bidding commitment in the day ahead market

As Figure 2.1 above showed, prior to 2012 GB day-ahead exchange liquidity was amongst the lowest in Europe relative to demand. Whilst reasonable baseload volumes were traded on an OTC basis, a lack of transparent hourly pricing at the day-ahead

¹⁷ DC price calculated using the DC pricing determination formulae as published by the Regulatory Authorities, and applied to the relevant traded commodity price curves on NDC trading dates.

¹⁸ NDC premia have also been calculated by comparing the last four DC pricing rounds to the NDC OTC Tullett Prebon close market prices from the trading date nearest to the publication of the DC prices. Under this method the NDC premia is higher, potentially as a result of comparing the DC to indicative NDC OTC mid-market close prices, rather than actual traded volumes. Please see the Appendix Table A1 for additional detail and breakdown of the comparison.

¹⁹ Source: Tullett Prebon, SEMO

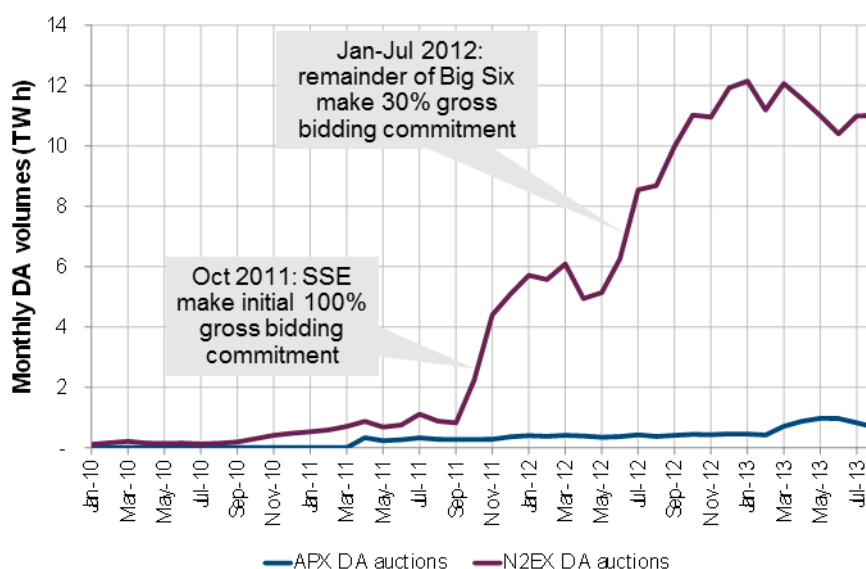
²⁰ Weighted average for Baseload, Mid-merit and Peak.

stage, combined with low forward market liquidity, was of concern to both regulators and market participants.

As a response to this, Ofgem launched its liquidity project to investigate further the issue and understand any interventions required to improve the functioning of the market. Market players responded with the 'Big Six' energy firms making voluntarily gross bidding commitments into the day-ahead exchange. Working in conjunction with the N2EX exchange²¹, the parties voluntarily committed to trading at least 30% of their generation and supply volume through day-ahead auctions. By placing the bids of their gross portfolio, as opposed to net portfolio, participants can be seen to have improved price discovery and market depth (thereby increasing pricing confidence).

These benefits can be observed in Figure 2.5 below, where the gross bidding commitment has had a significant impact on day-ahead liquidity, bringing GB volumes in line with the leading European peers. In its December 2013 'Secure and Promote' report Ofgem stated that liquidity in the day-ahead market timeframe is now sufficient, but it will continue to monitor with a view to intervening in the future if necessary.

Figure 2-5 Historical monthly day-ahead volumes²²



2.6.1. 'Secure and Promote' licence conditions in the forward market

GB forward market liquidity remained a concern, and in June 2013 Ofgem developed the 'Secure and Promote' Licence Conditions. Intended to 'lock in' the liquidity benefits of the gross bidding commitment, the 'Secure and Promote' condition places three obligations on licensees in the forward markets:

1. **Supplier Market Access Rules:** requires large market players to offer fair market access to small suppliers and independent operators. The obligation

²¹ The N2Ex exchange facilitated the gross bidding commitment by not charging full transaction fees where the parent company is the same for both sides of the trade (i.e. transfer of volume from the generation business unit to the retail business unit).

²² Source: APX, N2EX

includes requirements for credit and collateral arrangements, trade sizes and product ranges. This is intended to ensure that all market participants can access all products available.

2. **Market Making Obligation:** obligates large market participants to post bid and offer prices into the forward market, within a defined spread (see Table 2.5 below) during a specified time period. Market making activities must be performed on a specified platform, and requires licensees to offer a defined range of products in minimum trade sizes. This aims to support price discovery, improve liquidity and increase the robustness of reference prices.
3. **Reporting requirements:** obligates licensees to regularly report trading volumes on both forward and spot markets. This will allow Ofgem to monitor liquidity and consider if further intervention is required.

The 'Secure and Promote' licence conditions came into effect on 31 March 2014.

Table 2-5 'Secure and Promote' limits on difference between bid and offer prices²³

Baseload		Peak	
Month+1		Month+1	
Month+2		Month+2	
Quarter+1	0.5%	Quarter+1	0.7%
Season+1		Season+1	
Season+2		Season+2	
Season+3		Season+3	
Season+4	0.6%	Season+3	1%

2.7. General Implications for I-SEM design

Experience from the SEM and GB markets suggests that a liquid spot market is not sufficient for the development of a liquid forward market. Experience from the GB market suggests that a market with a high degree of vertical integration will not necessarily develop a liquid day-ahead or forward markets, without regulatory intervention. In the SEM vertical integration (both explicit and 'virtual'²⁴) is coupled with the presence of a dominant participant with significant market power.

We note, however, that the dynamics around vertical integration in the SEM may be different to those observed in GB because of the high levels of wind generation. The high volume of wind generation should create a strong economic incentive for vertically integrated suppliers to switch thermal generation for wind generation by bidding through the day-ahead and intra-day markets. In effect, this creates a similar dynamic as gross portfolio bidding does in the GB day-ahead market.

Liquidity in the forward market is essential to drive retail competition and to deliver efficient pricing to consumers, while liquidity in the day-ahead market is required for

²³ Source: Ofgem

²⁴ Whilst ESBPG is ring fenced from ESB Electric Ireland, 'virtual' vertical integration occurs as the long and short position is netted off at an overall group level.

efficient market coupling, reference pricing for forward contracts / renewable support mechanisms and price signals for demand side participation. From this we conclude that there will be a requirement for liquidity measures in I-SEM, regardless of the choice of HLD option.

2.8. I-SEM Market Power and Liquidity Measures

The measures that could be used to encourage forward market liquidity under Option 1 or Option 3 include:

- ▶ Directed Contracts, as under the current SEM;
- ▶ Market maker obligations on certain players, as required by Ofgem in GB under its 'Secure and Promote' proposals and suggested under Option 1 in the I-SEM consultation document;
- ▶ Monitoring of self-supply positions with the option to implement restrictions on dominant participants if required; and
- ▶ Maximum interconnector holdings by participant.

The advantage of DCs is that they provide suppliers with price certainty for setting their retail tariffs. However, they do not provide any liquidity benefit to independent generators, and require the RAs to take a direct role in setting wholesale prices, which ultimately is not part of the vision for the EU Target Model.

The market maker obligations do not specify an absolute price level, but require the dominant player to make a minimum volume available in the forward market on both the buy and sell side within a maximum specified bid-offer spread. This has the distinct advantage of providing liquidity to all market players, not just suppliers. These obligations should help to underpin the long term development of the forward market, without directly intervening in forward price levels.

Monitoring of self-supply positions can also stimulate forward liquidity without direct intervention on pricing levels and help mitigate against excessive 'virtual' vertical integration by dominant entities. However, self-supply requirements are less effective in generating forward liquidity when compared to alternatives, such as market maker obligations, as under self-supply ring-fenced participants can choose to withhold volumes and trade through the day-ahead market. It should also be noted that self-supply restrictions can be difficult to enforce.

Of these potential measures, our view is that market maker obligations combined with mandated volume obligations on the dominant participant in the I-SEM forward market may be the most effective market power mitigation and liquidity measure. This is because:

- ▶ It is compatible with an integrated single market for electricity in Europe;
- ▶ It can be easily enforced and monitored; and
- ▶ If implemented in the forward financial market under Option1, it will also give an economic incentive to provide liquidity (volume and cost reflective pricing) in the day-ahead market.

The requirement for the proposed measure applies equally to Option 3 and to Option 1. While less desirable, it may also be prudent to continue with a level of DCs in the near term until there is sufficient operational experience of the proposed measure to phase these out. Some form of self-supply monitoring by the RAs may also be advisable.

The I-SEM consultation document highlights the potential for efficient market coupling to weaken the market power of dominant participants. In the forward market this dynamic is only effective in reducing market power to the extent that there is not a concentrated holding of Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs) amongst dominant participants. Some form of maximum capacity holdings may therefore need to be considered to mitigate against this risk. Limiting capacity holdings will also increase liquidity in day-ahead and intra-day timeframes under Option 1, helping to ensure efficient market coupling is achieved.

3. FORWARD HEDGING DYNAMICS

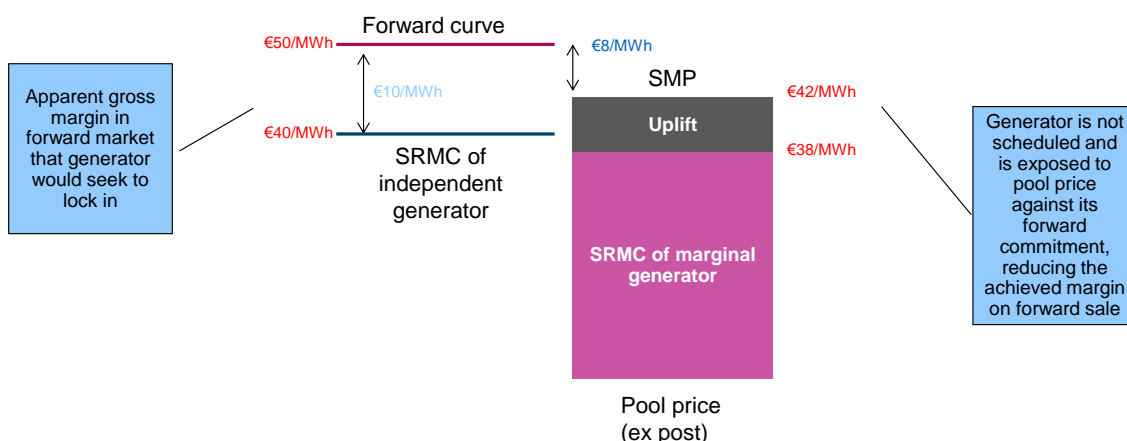
3.1. Scheduling Risk in Pool and Bilateral Markets

Problems with forward market liquidity in the current SEM are further exacerbated by pool scheduling risk. The dynamics of pool scheduling risk are explained below.

In a bilateral market, a generator is able to sell electricity forward and hedge its fuel cost. Having the option to self-dispatch at the time of delivery then guarantees it has locked in the margin on its forward sale. If at the time of delivery the spot price for electricity is below its Short Run Marginal Cost (SRMC), it will choose not to generate and instead purchase its requirements from the spot market. This allows the generator to then stockpile its fuel (in the case of coal) or sell it (in the case of gas) to achieve additional margin. Under this dynamic, a generator can only improve on the margin it has locked in through its forward hedging strategy.

Under the mandatory pool structure of the SEM, it is harder for a generator to execute a forward hedging strategy because it cannot determine its own schedule. This creates an anomaly whereby the generator can be 'in the money' in the forward market but is unable to capture the implied margin because it is not guaranteed to be scheduled through the mandatory pool. This problem is illustrated in Figure 3.1 below.

Figure 3-1 Risks associated with forward hedging under the SEM

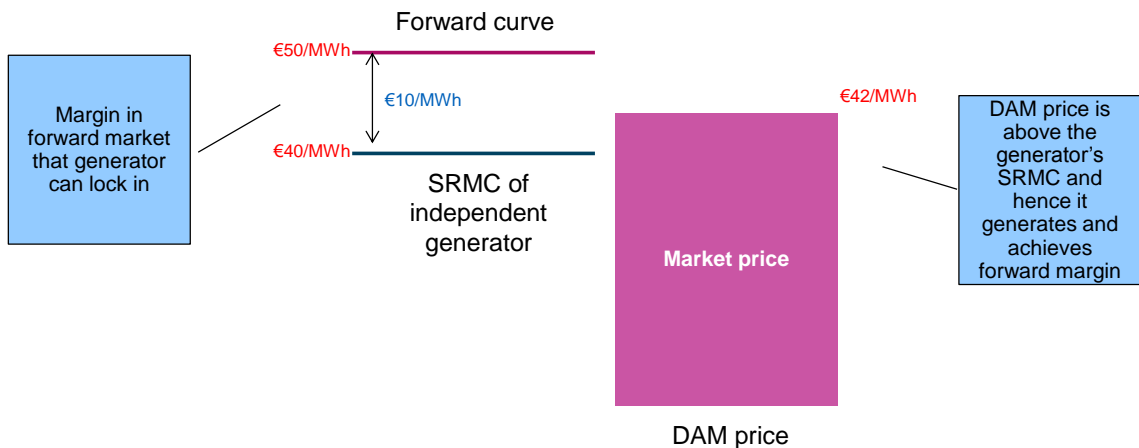


In this example, the forward curve (€50/MWh) is trading above the SRMC of the independent generator (€40/MWh). It therefore sells electricity forward and simultaneously hedges its fuel costs, thus in theory locking in a €10/MWh gross margin. At the day-ahead stage the generator submits an offer to the SEM based on its SRMC (€40/MWh). In this illustrative example, the generator's offer price is slightly above the SRMC of the marginal unit on the system (€38/MWh), causing the generator not to be scheduled in the pool. The generator therefore sells back its fuel hedges and in so doing generates a revenue equivalent to its SRMC. This payment offsets the costs of buying power from the pool (€42/MWh) to meet its forward commitments but because the pool has priced above the SRMC of the generator it results in the generator retaining a residual exposure to the pool. This residual exposure constitutes pool scheduling risk and means the generator only achieves a gross margin of €8/MWh, lower than the €10/MWh expected on its forward sale.

In a bilateral market this dynamic cannot occur. This is because a generator will self-schedule to meet physical forward commitments if it is unable to purchase power below SRMC in the day-ahead market, guaranteeing the margin on its forward sale.

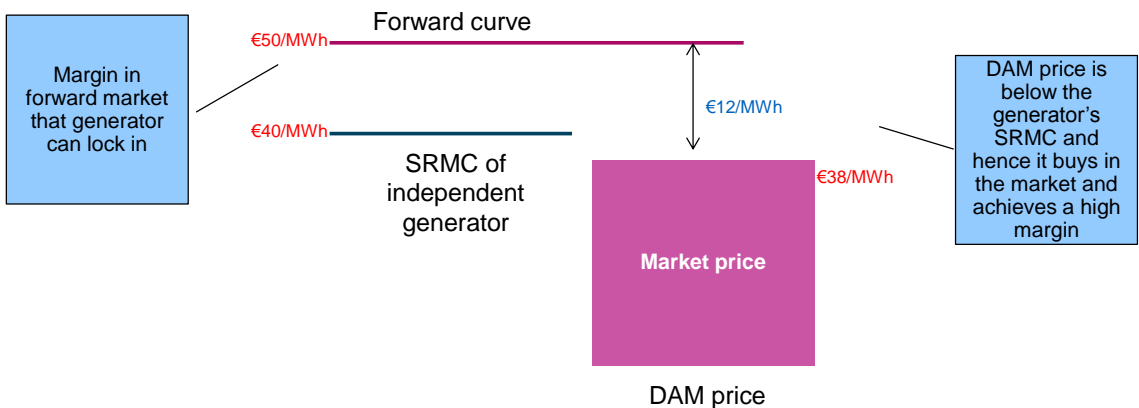
Figures 3.2 and 3.3 below illustrate the dynamics of forward hedging under bilateral trading arrangements with self-scheduling as a contrast to the forward hedging dynamics in the current SEM illustrated in Figure 3.1 above.

Figure 3-2 Forward hedging in a bilateral market – DAM price above SRMC



In Figure 3.2, the generator has sold electricity forward (€50/MWh) and simultaneously hedged its fuel costs (€40/MWh). The DAM (€42/MWh) is higher than its SRMC (€40/MWh) and the generator therefore self-schedules to meet its forward contract commitments. In so doing, the generator realises the margin it locked in through its forward hedging strategy (€10/MWh). This contrasts with the same example above under the current SEM.

Figure 3-3 Forward hedging in a bilateral market – DAM price below SRMC



In Figure 3.3, the generator has again sold electricity forward (€50/MWh) and simultaneously hedged its fuel costs (€40/MWh). The DAM price (€38/MWh) is below its SRMC (€40/MWh) and the generator meets its forward contract commitment by buying through the DAM and consequently does not generate. In so doing, the generator

achieves a better gross margin (€12/MWh) than the gross margin it locked in through its forward hedging strategy (€10/MWh).

3.2. Scheduling Risk and Market Power

A participant with a large and fuel diverse portfolio such as ESB can absorb scheduling risk significantly better than smaller portfolios or stand-alone generators. This is because they can be confident of maintaining a significant market share within the SEM pool. Given the relative sizing of CCGTs to SEM market demand levels, small portfolios or stand-alone generators are potentially exposed to scheduling risk for their entire market share within the SEM pool.

With increasing proportions of wind in the SEM, scheduling risk under a mandatory pool structure is likely to increase over time. Because scheduling risk introduces exposure on forward sales it is likely to disincentive merchant generation from participating in the forward market. In the case of a vertically integrated utility, scheduling risk manifests itself as fuel basis risk on retail sales increasing its requirements for hedging products in forward markets. The dynamics around scheduling risk therefore increase the market power of a dominant participant in forward market timeframes and is likely to have a detrimental effect on competition in the retail sector over the mid to long term.

3.3. To what extent can I-SEM address scheduling risk

Under Option 3, scheduling risk is likely to remain because of the use of an algorithm (in this case Euphemia) to determine generator positions within the mandatory DAM²⁵ pool. There will also be a high-degree of uncertainty around the pool dynamics if (as we would expect) there is widespread, but non-mandated use of sophisticated offer formats, and it will therefore be difficult for a generator to determine whether it is likely to be scheduled in the pool or not. Therefore, Option 3 may inherit many of the barriers to forward market development evident in the current SEM.

To the extent that Option 1 retains the ability for generators to self-schedule it eliminates scheduling risk. This will have a positive effect on participation in the forward market by merchant generation, as well as providing confidence to vertically integrated suppliers that their generation resources will be dispatched if they are in-the-money. Improved access to alternative generation sources will mitigate the ability of dominant participants to elevate prices in forward market timeframes.

Therefore, Option 1 is preferable to Option 3 because it eliminates scheduling risk from the I-SEM market design helping to stimulate participation by merchant generation in forward markets and further mitigating exertion of market power by dominant participants in forward timeframes. Separate measures to incentivise dominant participants to

²⁵ Euphemia supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, complex or sophisticated orders can only be executed fully or rejected fully, and this constraint can lead to Euphemia rejecting some complex orders even if they are in the money. See Baringa's 'Background Paper on HLD Option 3', Section 3 for further details.

provide adequate liquidity in forward market timeframes are required under both Option 1 and Option 3²⁶.

²⁶ While this paper specifically focuses on Option 1 and Option 3 our view is that such measures would be required under all HLD options due to the presence of a single large dominant portfolio with a diverse fuel mix in the SEM.

4. MARKET POWER IN THE DAY-AHEAD, INTRA-DAY AND BALANCING MARKETS

The presence of a single large generation portfolio with a diverse fuel mix in a small market such as the SEM means that significant market power mitigation measures will need to be implemented in the I-SEM regardless of the choice of HLD, particularly with a relaxation of the current SRMC bidding principles.

4.1. Relaxation of SRMC Bidding Principles

The final I-SEM design is likely to result in some form of relaxation of the SRMC bidding principles. There are a number of reasons for drawing this conclusion:

- ▶ Translation of SEM complex offer formats into Euphemia sophisticated offer formats under Option 3. Unless a translation formula is mandated a degree of freedom will need to be given to generators regarding how start up and no load costs are submitted to the market. The issue with mandating a formula is that it is likely to be discriminatory, resulting in more favourable outcomes for some generator types compared to others.
- ▶ The more likely use of simple rather than sophisticated bid formats under Option 1.
- ▶ Depending on CRM design, an increased requirement for generators to recover a proportion of their annual fixed (and capital) costs through 'scarcity rents' in the energy market, which would also facilitate efficient cross border trading with markets that do not have SRMC bidding principles.

Relaxation of SRMC bidding principles under I-SEM creates the challenge of how to prevent dominant participants from exploiting market power in the day-ahead, intra-day and balancing market timeframes.

4.2. Dynamics of market power in I-SEM day-ahead market

In a small market like the SEM, in which a single generation company has a dominant position, the advantage of having a large and fuel diverse portfolio of assets is significantly amplified. This is because the dominant portfolio has substantially more influence to increase (or decrease) prices within the day-ahead market under a diverse range of market conditions (e.g. relative coal and gas prices, demand levels, wind levels). Furthermore, the dominant portfolio participant can increase prices without the risk of a substantial loss of market share and by adjusting its offer prices across a range of units it does not need to accurately predict the marginal unit to be able to influence the price. In contrast, it is much more difficult for a smaller portfolio participant to influence price as it needs to predict if it is likely to be marginal and any attempt to increase prices (e.g. to recover start costs) results in a significant risk of reduced market share. These dynamics are illustrated in Figure 4.1 and Figure 4.2 below.

Figure 4-1 Ability of large portfolio player to set price in day-ahead market

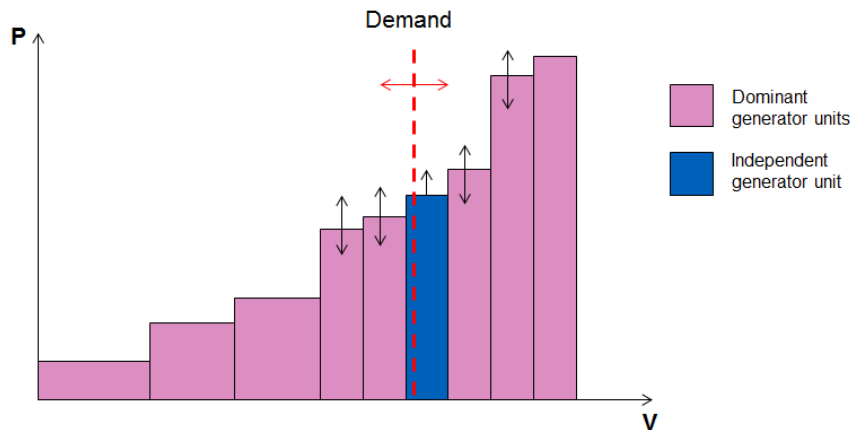
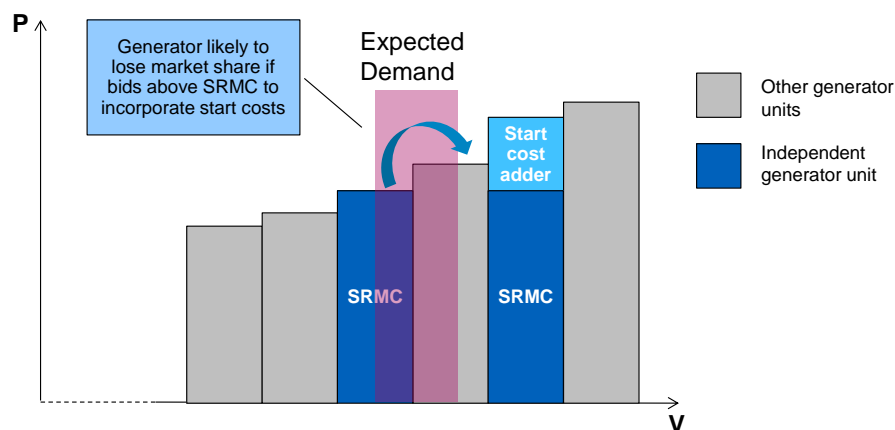


Figure 4-2 Bidding dynamics for an independent generator in the day-ahead market



4.3. Implications for I-SEM participants and consumers

In a mandatory pool structure the ability to influence day-ahead market prices is detrimental to merchant generators and suppliers because it distorts the pricing signals sent to the forward market. A dominant participant, in theory, could manipulate forward market price expectations by means of the day-ahead market. Increasing prices combined with implementation of a withholding strategy in forward timeframes could adversely affect retail competition. Decreasing prices combined with a saturation strategy in forward timeframes could adversely affect merchant generation. In both these scenarios exertion of market power by a dominant participant, over the long term, will have detrimental effects on competition levels in the I-SEM and therefore adversely affect consumers.

4.4. Day-ahead market power mitigation measures

Under Option 1 and Option 3 mandated financial forward market commitments could be used to mitigate the market power of dominant participants in day-ahead timeframes.

These could be combined with market maker obligations to prevent the financial withholding of contracts by dominant participants and thereby ensure sufficient volumes are sold. Other measures include:

- ▶ Timely publication of bids and offers from day-ahead market; and
- ▶ A robust, ex-post independent market monitoring function to identify and investigate uncompetitive behaviour.

Under Option 1 additional liquidity measures in the day-ahead timeframe would be required. These may include:

- ▶ Mandated bidding by dominant participants such that plant operating under physical bilateral contracts can be dispatched down in the day-ahead market²⁷. This would generate a similar effect to gross portfolio bidding in GB in a market with a single large dominant generation portfolio such as I-SEM.
- ▶ Mandated day-ahead volume requirements on dominant participants to ensure a minimum level of activity in the day-ahead market and build confidence in the DAM reference price.
- ▶ Mandated day-ahead volume requirements on dominant participants to ensure all available physically un-contracted generation is offered into the day-ahead market.
- ▶ Monitoring of physical self-supply positions in forward timeframes with the option to implement restrictions on dominant participants if required.
- ▶ Consideration of implementing FTRs rather than PTRs in order to maximise the interconnector capacity available for inclusion in the DAM coupling and price formation process.
- ▶ Implementation of unit based bidding in the day-ahead timeframe, if possible, to improve transparency.

It is worth noting that the additional market power mitigation measures outlined above for Option 1 are implicit but non-targeted in the design of Option 3. There is therefore additional flexibility provided to regulators under Option 1 to focus market power mitigation measures towards addressing specific dominance issues (similar to the approach taken by Ofgem within the GB electricity market). Option 1 also provides the additional benefit that such measures can then be 'rolled back' gradually once there is demonstrable evidence that the conditions for adequate competition (and therefore efficient market operation) have been achieved.

In conjunction with the measures outlined above it is worth noting that exchanges have their own market conduct rules that will also provide restraints on the exercise of market power. Furthermore, European trading regulations such as REMIT will also play a role in limiting market power by increasing market transparency.

²⁷ We note that similar measures have been implemented in the Iberian market since 2009, with sellers of physical bilaterals obliged to post a buying bid at opportunity cost in the DAM.

4.5. Dynamics of market power in I-SEM intra-day market

Large portfolio participants also hold significant market power in the intra-day timeframe which could be exercised by manipulating market prices or withholding volumes. This is of equal concern under Option 1 or Option 3 because of the relatively low level of interconnection in the market.

4.6. Intra-day market power mitigation measures

Mandating intra-day trading through European platforms as envisaged under Option 3 will increase transparency but there is a risk that the European intra-day trading platform may not be operational in time for the start of the I-SEM. A similar level of transparency could be achieved by mandating intra-day trading through I-SEM exchanges or broker screens as an interim measure. Trade volumes, in theory, should then naturally migrate to the European platform to avail of the additional liquidity provided by European market integration. The level of migration could then be actively monitored and steps taken in the future to encourage migration if a natural pooling of liquidity onto the European platform did not occur. This alternative approach could be adopted under Option 1 or Option 3.

Under Option 1 and Option 3 the following market power mitigation measures in the intra-day timeframe are likely to be required:

- ▶ Mandate intra-day trading via exchanges or broker screens.
- ▶ Mandated bidding by dominant participants of plant delivering physical bilateral positions in the intra-ahead market.
- ▶ Mandated intra-day volume requirements on dominant participants to ensure all physically un-contracted generation is offered into the intra-day market.
- ▶ Timely publication of bids and offers from intra-day market.
- ▶ A robust, ex-post independent market monitoring function to identify and investigate uncompetitive behaviour.

Under Option 1 the following additional market power mitigation measure in the intra-day timeframe may be desirable:

- ▶ Implementation of unit based bidding in the intra-day timeframe, if possible, to improve transparency.

4.7. Dynamics of market power in I-SEM balancing market

The balancing markets in Option 1 and Option 3 fulfil two different purposes, enabling the TSO to conduct energy balancing actions as well as resolving system constraints (such as network congestion or inertia requirements). Given the proposal for participants' submissions to the balancing market to take the form of simple incremental and decremental bids, we assume that the current SEM SRMC bidding principles will need to be relaxed in the balancing timeframe, as in the other market timeframes. Relaxation of the bidding principles brings the risk that participants may exercise market power, influencing the imbalance price on a SEM-wide basis, or potentially exacerbating constraints costs on a local level.

HLD Option 1 and Option 3 may therefore present opportunities for exertion of market power in the balancing market. In the case of I-SEM, it is notable that the dominant generation portfolio includes all the large scale hydro and pumped storage assets. Experience from other markets has shown that these highly flexible units can exert significant pricing power in balancing timeframes. In GB, for example, with four pumped storage assets controlled by three portfolio players, it is not uncommon for individual pumped storage units to submit a balancing bid-offer spread of £500/MWh or more. By contrast, in the current SEM arrangements with central dispatch, pumped storage operation is optimised to minimise overall system costs.

Generation portfolios with a large geographical spread will also increase opportunities to exert local market power. In the GB trading arrangements, Ofgem investigations of generator behaviour behind transmission constraints have indicated the potential to exert local market power²⁸. A Transmission Constraint Licence Condition (TCLC) was introduced in response to these concerns, with the objective of:

- ▶ Preventing generators from making uneconomic dispatch decisions that create or exacerbate a transmission constraint; and
- ▶ Preventing generators from obtaining an excessive benefit from bids they make to reduce their output during periods of export constraint.

It is worth noting, however, that in balancing timeframes small portfolio, and even stand alone generators, can exert significant local market power due to their geographical location or a particular temporal requirement of the TSO. Mitigation of market power in balancing timeframes therefore needs serious consideration under both Option 1 and Option 3 but is unlikely to be significantly influential in the choice of HLD²⁹.

The requirement for market power mitigation measures in the balancing timeframe in I-SEM may be more pronounced than some other markets due to the small number of participants relative to the volume of balancing actions likely to be required by the TSO to achieve a feasible schedule.

²⁸ For example, see: <https://www.ofgem.gov.uk/ofgem-publications/40530/market-power-concerns-initial-policy-proposals.pdf>

²⁹ To the extent that SRMC bidding principles are relaxed and generation schedules from Euphemia do not accurately reflect the technical characteristics of generators, there is likely to be no difference between Option 1 and Option 3 in terms of mitigating market power in the balancing timeframe.

4.8. Balancing market power mitigation measures

Under Option 1 and Option 3 the following market power mitigation measures in the intra-day timeframe are likely to be required:

- ▶ Pre-contracting for balancing services at regulated prices. These could be specifically targeted, for example at pumped storage and hydro units, and include requirements to make plant available at short notice, or turn down/shut off at short notice.
- ▶ Explicit licence conditions relating to exploiting a position of market dominance, enforced by active monitoring.
- ▶ Timely publication of bids and offers from the balancing market.
- ▶ A robust, ex-post independent market monitoring function to identify and investigate uncompetitive behaviour.

5. CONCLUSIONS

The main conclusions of this paper are summarised below:

- ▶ Analysis of the current SEM forward market indicates exceptionally low levels of market led liquidity and exhibits dynamics that could be indicative of the exertion of market power. We also note:
 - The low volumes traded through the OTC platform.
 - The extremely large bid / offer spreads evident on the OTC platform.
 - The large differential between the pricing level of DCs and NDCs.
 - The limited opportunities to trade in the SEM forward contract market compared to other European markets.
 - Consequently the general lack of industry led reporting on the dynamics of the SEM forward contracts market – e.g. by publications and platforms such as Heren, Spectron, and Platts.
 - The general lack of regulatory reporting and detailed analysis carried out on the dynamics of the SEM forward contracts market.
 - The general lack of transparency, which makes the detailed analysis of market trading dynamics difficult.

We therefore conclude that further examination of the SEM forward contracts market is required as part of the I-SEM design process:

- ▶ We note that experience in the GB market indicates that regulatory reporting and appropriate intervention can deliver liquidity in both forward and day-ahead timeframes.
- ▶ We recommend that the I-SEM HLD carefully considers the importance of liquidity in forward market timeframes and note from the analysis completed on the current SEM forward market that robust market power mitigation measures in forward timeframes are likely to be required under all market design options.
- ▶ We suggest that market maker obligations combined with mandated volume obligations on the dominant participant in the I-SEM forward market may be the most effective market power mitigation and liquidity measure to introduce.
- ▶ We note that these will also encourage liquidity into the day-ahead market timeframe if financial forward contracts are imposed under Option 1.
- ▶ We note the issue of scheduling risk in the current SEM design and its potential negative effects on forward market power and consequent implications for merchant generators and suppliers and therefore ultimately customers.
- ▶ We identify the risk that scheduling risk under Option 3 will likely remain. For further detail on this, please refer to Baringa's 'Background Paper on HLD Option

3' which discusses potential concerns associated with the use of complex order formats in the Euphemia day-ahead coupling algorithm.

- ▶ We note how self-scheduling to meet forward bilateral commitments under Option 1 would remove this scheduling risk and thereby incentivises participation by merchant generation. This will help mitigate market power in forward market timeframes and increase the competitiveness of pricing levels of I-SEM forward contracts delivering lower costs for consumers.
- ▶ We note the likely relaxation of bidding principles under I-SEM and the consequences for market power mitigation in day-ahead, intra-day and balancing timeframes under both Option 1 and Option 3.
- ▶ We make detailed suggestions around market power mitigation measures that could be introduced into day-ahead, intra-day and balancing timeframes under Option 1 and Option 3. Furthermore, we note that significant market power mitigation measures are required under all HLD options because of the presence of a single large dominant generation portfolio with a diverse fuel mix in the SEM.
- ▶ While recognising the potential benefits of Option 3 in providing day-ahead market liquidity we note that a similar level of liquidity can be generated under Option 1 by the appropriate market power mitigation measures being implemented, and note the additional benefit in forward market timeframes of eliminating scheduling risk. Moreover, under Option 1 these measures can be monitored by regulators and relaxed if there is demonstrable evidence that the conditions for adequate competition (and therefore efficient market operation) in each market timeframe have been achieved.
- ▶ We note that the high level of wind generation in the I-SEM may also act as a strong economic incentive on vertical integrated utilities to participate in day-ahead and intra-day markets under Option 1, further promoting liquidity. To avoid dilution of this incentive robust market power mitigation measure in the balancing market, such as those suggested, are required. We observe that these measures are required under both Option 1 and Option 3 to ensure the proper functioning of the I-SEM in balancing timeframes.

APPENDIX

Table A1 provides a breakdown of NDC premia calculated by comparing the last four DC pricing rounds to the NDC OTC Tullett Prebon close market prices from the trading date nearest to the publication of the DC prices. Table A2 provides a simple average of the NDC premia for comparison with Table 2.4 in Section 2.4.5.

Table A1 NDC OTC premia over last four DC rounds

Contract period	DC Price			NDC OTC Price			NDC premia		
	Baseload	Mid-Merit	Peak	Baseload	Mid-Merit	Peak	Baseload	Mid-Merit	Peak
	07/03/2014 (round 8)			12/03/2014					
Q3 2014	57.62	64.00	n/a	61.63	73.25	n/a	4.01	9.25	n/a
Q4 2014	64.95	74.54	114.59	65.25	75.88	125.75	0.30	1.33	11.16
Q1 2015	69.07	77.43	117.45	70.00	76.38	133.75	0.93	-1.06	16.30
Q2 2015	57.85	63.24	n/a	61.85	71.25	n/a	4.00	8.01	n/a
	12/11/2013 (round 7)			13/11/2013					
Q2 2014	62.32	69.56	n/a	64.80	73.75	n/a	2.48	4.19	n/a
Q3 2014	59.06	66.30	n/a	63.38	69.25	n/a	4.32	2.95	n/a
Q4 2014	65.31	75.09	115.35	69.00	75.55	116.00	3.69	0.46	0.65
Q1 2015	68.36	76.69	115.57	69.80	n/a	126	1.44	n/a	10.43
	26/08/2013 (round 6)			24/07/2013					
Q1 2014	70.52	80.62	131.41	73.50	81.33	137.25	2.98	0.70	5.84
Q2 2014	59.70	66.10	n/a	60.85	70.05	n/a	1.15	3.95	n/a
Q3 2014	57.67	65.19	n/a	59.95	69.03	n/a	2.28	3.84	n/a
Q4 2014	64.40	73.87	112.35	66.75	n/a	n/a	2.35	n/a	n/a
	27/06/2013 (round 5)			19/06/2013					
Q4 2013	67.82	78.25	122.98	70.40	82.50	n/a	2.58	4.25	n/a
Q1 2014	71.69	83.31	132.50	71.65	85.50	n/a	-0.04	2.19	n/a
Q2 2014	60.27	66.51	n/a	61.90	72.50	n/a	1.63	5.99	n/a
Q3 2014	58.12	65.40	n/a	62.25	73.50	n/a	4.13	8.10	n/a

Table A2 Average NDC OTC premia over last four DC rounds

	Baseload	Mid-Merit	Peak
Average NDC OTC premia (€/MWh)	2.39	3.87	8.88

Appendix 3 – Baringa Report entitled “Background paper on HLD Option 3”

► **I-SEM HLD Consultation:
Background paper on HLD Option 3**

CLIENT: Viridian

DATE: 04/04/2014

V3.0

Version History

Version	Date	Description	Prepared by	Approved by
3.0	4/4/2014	Final draft	AP	DS

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EXECUTIVE SUMMARY

This report has been prepared by Baringa for Viridian to provide background to the assessment of the 'Mandatory Centralised Market' Option 3 proposed as one of four potential options for a new SEM High Level Design (HLD). This HLD option would require SEM generation and demand to participate exclusively in the Day Ahead Market (DAM) and Intra Day Market (IDM) as the only markets for ex-ante physical trading.

We have considered whether the Iberian market, encompassing Spain and Portugal, can be viewed as a comparable benchmark for the 'Mandatory Centralised Market' HLD option, as suggested in the I-SEM consultation paper. Although there are parallels between the SEM and Iberian market, we note that participation in the Iberian DAM is voluntary, accounting for 71% of Iberian demand in 2013. Spanish and Portuguese generators do not, therefore, rely exclusively on the DAM coupling algorithm to formulate their day-ahead schedules. Indeed, all the European markets which have implemented the Euphemia coupling algorithm provide alternative routes to market and allow participants to self-schedule generation.

The success of the mandatory DAM proposal will be dependent on SEM generators being able to manage unit commitment with complex or sophisticated order formats using the day-ahead coupling algorithm, Euphemia. To date, only the Iberian market has implemented support for sophisticated orders in Euphemia, but the thermal plant utilising these order formats represent a much smaller proportion of the overall market than would be expected in the SEM. Extensive use of complex order formats by marginal or 'at-the-money' resources can prove problematic for market clearing algorithms, as was illustrated by an incident in August 2013 when the legacy Nord Pool algorithm was unable to set a clearing price due to the handling of complex orders. We therefore recommend rigorous testing of the Euphemia algorithm is conducted under potential I-SEM stress scenarios prior to any decision to proceed with HLD Option 3. Testing should be focused on verifying the performance of the algorithm in a relatively small market with a high proportion of large units making extensive use of sophisticated offer formats.

Given the potential risks of relying on a mandatory day-ahead scheduling process and the likely time restraints on testing Euphemia in a SEM context, HLD Option 1 may present a lower risk implementation pathway for the I-SEM programme than Option 3. This would provide SEM generators with an alternative route to market in the event that the use of sophisticated order formats proved unsatisfactory, and ensure access to the full range of risk management tools available to participants in other European coupled markets.

1. INTRODUCTION

The SEM Committee is currently consulting on four potential options for a new High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) in Ireland and Northern Ireland. One of these options, the 'Mandatory Centralised Market' (Option 3), would require SEM generation and demand to participate exclusively in the Day Ahead Market (DAM) and Intra Day Market (IDM) as the only markets for ex-ante physical trading. By contrast, the other HLD options feature voluntary participation in the DAM and IDM.

This report has been prepared by Baringa for Viridian and examines two aspects of the 'Mandatory Centralised Market' HLD option:

- ▶ The extent to which other European markets have been based on mandatory participation in the DAM;
- ▶ The use of the Euphemia market coupling algorithm to derive day-ahead schedules for SEM generators within a mandatory pool structure.

2. COMPARABLE EUROPEAN MARKETS

The I-SEM consultation paper states that the 'Mandatory Centralised Market' HLD option is comparable to the design of other European electricity markets:

*'This option is close to the design of electricity markets in the NWE region, which are built on the concept of a liquid DAM, and also similar to the Iberian market in particular which exhibits high liquidity in the DAM and IDM.'*¹

This section explores whether other European markets, notably Iberia, provide a useful comparison for how the I-SEM might operate under the 'Mandatory Centralised Market' HLD option.

2.1. Day-ahead liquidity

The day-ahead trading timeframe is very much at the heart of the European market coupling project. Across much of Europe, including the North-Western European (NWE) region, historical and current trading patterns exhibit much higher volumes of market activity day-ahead compared to the intra-day and balancing timeframes. Under the European Target Model and the CACM Network Code, transmission flows between interconnected markets will be determined primarily by the coupling of day-ahead power exchanges.

However, the 'Mandatory Centralised Market' HLD option differs from the prevailing design in most European markets by mandating participation in the day-ahead coupling process. All SEM generators and suppliers (over a de minimis level) would be required to submit unit-based offers and bids to the DAM, with the results of the day-ahead coupling process nominated directly to the TSO as a planned generation schedule. By contrast, DAM participation is voluntary in the NWE region, which includes Germany, France, Great Britain, Netherlands, Norway, Sweden and Denmark. Generators and suppliers in these markets may submit portfolio offers and bids to their local power exchange for inclusion in the day-ahead market coupling process. Generators then decide how to schedule their units to fulfil their commercial obligations, taking account of their cleared bids and offers in the DAM.

Although DAM participation is voluntary in the NWE region, many of these markets exhibit high levels of day-ahead liquidity. The Nordic and German spot markets, in particular, are generally regarded as highly liquid, with robust price indices based on the DAM underpinning the forward markets. Nord Pool day-ahead exchange volumes represent around 75% of consumption in the Nordic countries, while day-ahead liquidity in Germany is closer to 50% of demand. In GB, day-ahead exchange liquidity has improved significantly in recent years, approaching 50% of demand during 2013. Other markets such as France exhibit lower levels of day-ahead liquidity, at 10–20% of demand.

The Iberian market, encompassing Spain and Portugal, has been cited as a comparable test case for the I-SEM 'Mandatory Centralised Market' HLD option. This is because generators in this market submit unit-based offers in the DAM, and can utilise sophisticated offer formats to help manage scheduling risks. We explore the Iberian

¹ SEM-14-008, paragraph 8.2.5

market in more detail in the next section and consider the validity of the comparison with the SEM. It is worth noting, however, that participation in the Iberian DAM is voluntary, since generators do have the option of striking physical bilateral contacts and then self-dispatching to fulfil them.

2.2. The Iberian market

2.2.1. Market comparisons

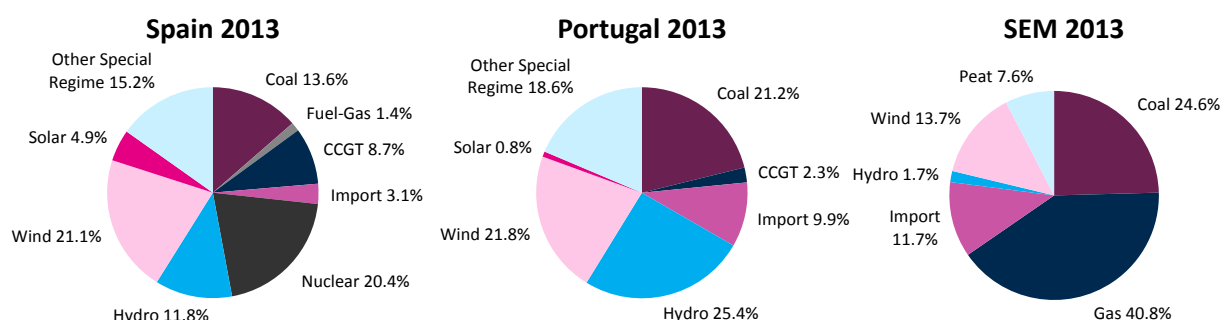
Review of the Iberian market indicates a number of characteristics in common with the SEM including: limited interconnection to neighbouring systems, geographical location on the periphery of the European electricity network, and CCGTs and wind providing the largest shares of the generation capacity mix. Table 2-1 below summarises similarities and differences between the Iberian and all-island markets.

Table 2-1 Comparison of Iberian market and SEM

	Similarities to SEM	Differences to SEM
Fundamentals	<ul style="list-style-type: none"> Limited interconnection to other markets Significant renewable and CCGT development over the last decade 	<ul style="list-style-type: none"> Considerably larger market Significant hydro capacity provides system flexibility More diversified plant mix with material contributions from nuclear, CHP and solar
Market design (I-SEM with mandatory DAM)	<ul style="list-style-type: none"> Unit-based bidding in DAM and IDM Sophisticated offer formats available to proxy technical and commercial generation parameters 	<ul style="list-style-type: none"> Voluntary participation in DAM Ability to self-schedule to meet physical bilateral commitments

Reviewing generation mixes, it is notable that conventional thermal generation (coal, CCGTs, fuel oil) accounted for less than 25% of 2013 demand in Spain and Portugal, compared to over 65% of demand in the SEM. Although CCGTs represented the largest share of Spanish installed capacity in 2013 (over 22%), they contributed less than 9% of total generation. In addition to thermal generation and renewables, the Iberian generation mix also features material contributions from hydro, nuclear and CHP (included within 'Other Special Regime' in the pie charts).

Figure 2-1 Iberian and SEM generation mix, 2013²

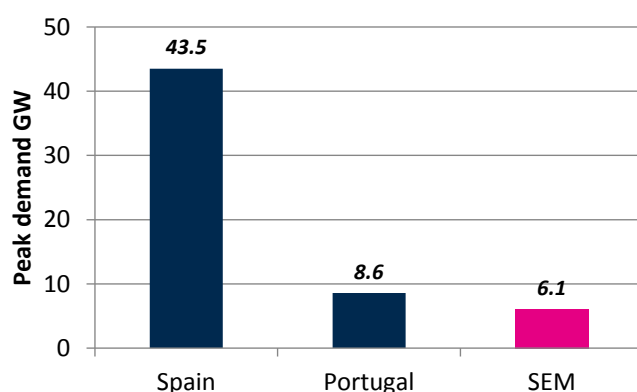


² Source: OMIE, SEMO

The relatively small share of conventional thermal generation compared to the SEM is significant from a market design perspective: as we shall examine later, the evidence from the Iberian market is that coal and CCGT generators are most likely to make use of sophisticated offer formats in the DAM to represent parameters such as ramp rates, start costs or minimum run times. The complexity of solving the day-ahead market clearing algorithm is likely to increase with the proportion of generation using sophisticated bids.

The Iberian market is clearly larger than the SEM, as shown by the comparison of peak demand values in the I-SEM HLD paper and reproduced below:

Figure 2-2 Market size comparison, 2012³



From a market design perspective, generation unit size relative to overall demand can be an important consideration. The majority of Spanish CCGT units, for example, are of a similar size to those in the SEM, around 400 MW. If thermal plant such as CCGTs impose integer constraints in the DAM by using block or sophisticated bids, these constraints may influence the performance of the market clearing algorithm, particularly in a market such as the SEM where there is a higher ratio between individual unit size and demand⁴. As we describe later in this report, other European power exchanges have limited the size or number of non-simple bids in their respective DAMs to mitigate risks to algorithm performance⁵.

2.2.2. Bilateral physical trading

As we have already noted, a key difference between the Iberian market and the proposed I-SEM 'Mandatory Centralised Market' is that DAM participation is voluntary in Spain and Portugal due to the ability to strike physical bilateral contracts.

Iberian market participants are obliged to submit offers to the DAM for available generation units over 50 MW to the extent they are not covered by bilateral contracts with physical settlement.

³ Source: SEM-14-008, Figure 1

⁴ A high ratio between unit size and overall system size implies that the algorithm solution may be highly sensitive to the resolution of individual integer constraints.

⁵ The Iberian market does not impose limits on the volume of non-simple bids but does require unit-based bidding in the DAM, whereas the majority of European power exchanges operate portfolio bidding arrangements

In practice, the trading volume in the DAM accounted for 71% of Iberian demand in 2013, according to data from the market operator OMIE. By this measure, day-ahead liquidity in the Iberian market is higher than the European average, and comparable to Nord Pool. Intra-day trading volumes in the Iberian market are also relatively high by European standards, with the result that the DAM and IDM combined represented 83% of demand in 2013.

Data from the Spanish TSO, REE, suggests that the utilisation of bilateral contracts can vary significantly by plant type. In 2013, bilateral contract volumes represented around 77% of scheduled nuclear generation, 44% for hydro, 19% for coal, and 6% for CCGTs.

While generators and retailers in the Iberian market are free to strike physical bilateral contracts, we note that the regulatory framework does incorporate measures to promote transparency, dispatch efficiency and forward liquidity. Since 2009, sellers of physical bilaterals have been obliged to post a buying bid at opportunity cost in the DAM, so that generating units will only be dispatched if their running costs are below market price. In Spain, periodic auctions have been held to improve retailers' access to forward products⁶.

2.2.3. Sophisticated offer formats

Support for sophisticated offer formats is a characteristic feature of the Iberian DAM. In addition to simple bids of price/quantity pairs, the following complex conditions are supported:

- ▶ *Indivisibility* – an 'all or nothing' condition applying to the first block of power in each period⁷;
- ▶ *Minimum income condition* (MIC) – a minimum daily revenue, as defined by fixed and variable terms, for an order to be accepted;
- ▶ *Load gradient* – equivalent to a generator ramp rate;
- ▶ *Scheduled stop* – specifying a subset of bids to allow a non-abrupt plant shut-down in the case a MIC order is not accepted.

The Iberian DAM has applied the pan-European market clearing algorithm, Euphemia, since 4 February 2014 (coinciding with the launch of NWE market coupling)⁸. Euphemia has been designed to replicate the sophisticated order formats supported by the previous Iberian market algorithm. The formulation of MICs and other complex orders in Euphemia is therefore based on the Iberian specification. The previous Iberian DAM clearing algorithm dated to the 1990's and was arguably less sophisticated than the market scheduling software currently deployed in the SEM: the Iberian algorithm used an iterative heuristic technique and did not guarantee an optimal solution, whereas the SEM software aims to optimise the unit commitment problem.

⁶ We note recent statements that the Spanish energy ministry is considering overhauling the 'CESUR' auction process to address transparency concerns.

⁷ Note the indivisibility condition cannot be combined with any other complex condition

⁸ The Iberian market is currently operating in parallel with the NWE region, utilising the common Euphemia algorithm but retaining explicit auctions to manage transmission capacity between Spain and France. Full market coupling of Iberia and NWE is targeted for May 2014.

The Iberian market operator, OMIE, publishes participant DAM and IDM offer data with a 90 day lag. At the time of writing, the latest publicly available offer data is from December 2013, pre-dating the transition to the Euphemia algorithm. We have reviewed the published DAM offer data to assess the extent to which participants in the Iberian market have made use of sophisticated offer formats. Given that Euphemia has replicated the functionality of the previous Iberian algorithm, our understanding is that the use of sophisticated offer formats (including MIC orders) is not expected to change significantly under Euphemia.

Our analysis of participant offer data from the last three months of 2013 suggests that only CCGT, coal, and oil plant used MIC orders or specified ramp rates. Using the daily offer files, we have estimated that approximately 60% of CCGT capacity used MIC orders with a fixed cost term, while around 90% used MIC orders with the variable costs term (note the fixed and variable terms can be combined). The majority of coal / oil capacity also used MIC variable terms, but on a relative basis, there was less use of the MIC fixed term. Only around 10% of CCGT, coal, and oil capacity specified ramp rates in their orders.

Table 2-2 Sophisticated order formats in Iberian market, Q4 2013⁹

Offer format	Plant type	Oct-13	Nov-13	Dec-13*
MIC fixed	CCGT	60%	62%	58%
	Coal / oil	33%	53%	33%
MIC variable	CCGT	87%	86%	95%
	Coal / oil	84%	88%	75%
Load gradient	CCGT	10%	10%	10%
	Coal / oil	13%	9%	11%

We can therefore conclude that the majority of thermal plant in the Iberian market do use sophisticated order formats, but we note that these generators accounted for under 25% of the overall fuel mix in 2013. In terms of the overall number of offers submitted to the Iberian DAM, MIC orders with fixed or variable terms represented around 16% of the daily 'sales' orders during Q4 2013.

2.3. Summary

As indicated by the I-SEM HLD consultation paper, there are some parallels between the 'Mandatory Centralised Market' Option 3 and the Iberian market. The Iberian market implemented the Euphemia market coupling algorithm in February 2014 with unit-based bidding and support for sophisticated offer formats to help generators manage scheduling risks. However, participation in the Iberian DAM is voluntary, and generators have the option to self-dispatch to meet physical bilateral contract commitments. Moreover, the thermal plant utilising sophisticated order formats in the Iberian market represent a much smaller proportion of the overall market than would be expected in the

⁹ Source: OMIE. *December data to 26/12/2013

SEM. The unit size of thermal plant is comparable between the two markets, but the ratio between individual unit size and overall system demand is much higher in the SEM.

The Iberian market therefore differs from the mandatory DAM proposal for the I-SEM in terms of the number and relative size of generators using sophisticated offers, as well as in providing an alternative route to market via physical bilateral contracts.

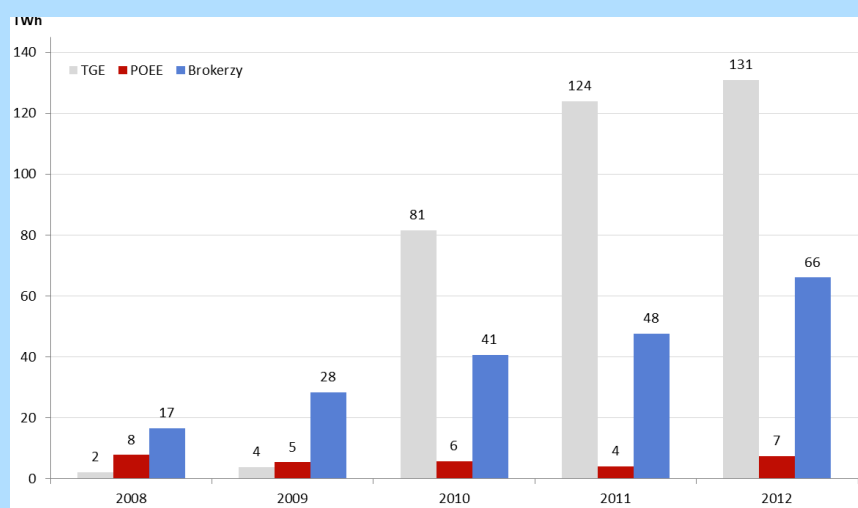
Like the Iberian market, DAM participation is voluntary in the markets which have implemented Euphemia in the NWE region. Other markets such as Poland (see Box 1) have implemented measures to improve exchange trading liquidity, but have allowed flexibility in terms of how trading obligations are met across forward and spot timescales.

Box 1: Exchange trading in the Polish market

The Polish market is sometimes cited as an example of more centralised electricity trading arrangements, and may therefore provide another comparator for the I-SEM. As in the Iberian and NWE regions, trading in the Polish DAM is voluntary.

Historically, volumes traded through the power exchanges in Poland were very low as a result of vertical integration and bilateral contractual arrangements. In 2007, for example, trading volumes on the DAM accounted for 2.2% of Polish electricity consumption. However, following an amendment to the Energy Law in 2009, generators have been required to sell more of their output through either online exchanges or through open tender, thus increasing market liquidity. By 2013, DAM trading volumes on the POLPX exchange had increased to 22.2 TWh, equivalent to 14% of demand¹⁰. Overall POLPX volumes across the forward, DAM and IDM timescales grew by over a third in 2013 to 177 TWh, with the majority of trading volumes in the forward market.

Figure 2-3 Polish exchange (TGE, POEE) and broker volumes¹¹



The trading obligation imposed upon Polish generators requires them to sell 15% of output on exchange, but this can be met in the forward market as well as the DAM. Renewable and CHP generation is excluded from the obligation, while generators under a transitional compensation scheme (relating to the termination of long term contracts) are obliged to sell 100% of their output on exchange.

The Polish market therefore provides an example of how regulatory intervention has had the effect of improving liquidity over both the forward and DAM timescales. In terms of the I-SEM HLD consultation options, the Polish market could be characterised as 'Option 1' with liquidity intervention measures.

¹⁰ Sources: Towarowa Gielda Energii (POLPX), PSE

¹¹ Source: Towarzystwo Obrotu Energią

3. EUPHEMIA AND THE I-SEM

Under the current SEM trading arrangements, the centralised scheduling and pricing algorithm ensures that the generator market schedules are both technically feasible and commercially viable. Generators explicitly submit technical parameters (such as ramp rates, minimum stable levels and minimum run times) for consideration by the algorithm. The Uplift component of the market price in the SEM guarantees the recovery of variable operating costs, including start and no load costs, for generation plant selected to run in the market schedule.

By contrast, in more decentralised trading arrangements, market participants will typically internalise decisions on how to factor generation technical and cost constraints within their scheduling and pricing. Historically, day-ahead trading on power exchanges such as Nord Pool has focused on simple hourly products, with the auction clearing independently for each hour of the following day. The power exchanges in decentralised markets have not, therefore, played a significant role to date in managing inter-temporal considerations such as start costs and minimum run times on behalf of participants.

In decentralised markets, participants typically have a range of tools available to manage the risks associated with scheduling generation and balancing their positions:

- ▶ Participation in the organised DAM is voluntary, so participants have the option of striking physical bilateral contracts and then self-dispatching generation to meet forward commitments;
- ▶ Participants can internalise factors such as start costs within their power exchange bids (in contrast to the current bidding restrictions in the SEM);
- ▶ Participants determine their own generation schedules after the DAM auction process and can modify their nominations to the TSO until gate closure for each delivery period (e.g. one hour before delivery);
- ▶ There are multiple opportunities for re-trading and fine tuning positions prior to delivery, including OTC and exchange-based platforms.

In a sense, the proposed I-SEM 'Mandatory Centralised Market' HLD option can be considered as an attempt to move features from the current SEM pool to the day-ahead timeframe using the Euphemia algorithm. As described in the I-SEM consultation paper, this HLD option is very much dependent on the new market coupling algorithm, Euphemia, providing SEM generators with the functionality to manage unit commitment and market dispatch:

'Of particular relevance for the All-Island market in reaching an efficient dispatch position is the efficiency of the unit commitment process. In this option, sophisticated unit-based bids into the DAM are used as the prime determinant of unit commitment –these have been developed in other markets to allow market participants to manage the risk of start-up costs (in the optimisation by Euphemia across a whole trading day), without requiring the full (three part) complex bids

currently used in the SEM (as the sophisticated bids effectively act as a proxy for the full complex bids).¹²

Euphemia does provide support for more sophisticated order formats compared to the previous market clearing algorithms used by power exchanges in the NWE region. As the I-SEM paper suggests, it is possible these sophisticated order formats could be used by SEM generators to proxy the technical and commercial parameters that are handled explicitly in the current SEM. A key question for the ‘Mandatory Centralised Market’ HLD option, however, is whether generators are likely to lose the guarantees of technical feasibility and cost recovery provided by the current SEM algorithm, but without gaining the benefits of access to the full range of risk management tools available to participants in other European coupled markets?

3.1. Sophisticated order formats

Prior to the launch of NWE market coupling in February 2014, a variety of market clearing algorithms were utilised by the local power exchanges. Euphemia has been designed to support pan-European market coupling while meeting the individual requirements of the local exchanges with regard to order formats. In practice, one of the existing local algorithms¹³ was used as a starting point, and functionality developed to support specific features of the Iberian and Italian markets amongst others. As a result, Euphemia can handle a multitude of order formats, ranging from simple hourly and block products through to more complex block formats (e.g. linked, flexible, exclusive) and sophisticated conditions (e.g. MIC, Scheduled Stop and Load Gradient as described earlier for the Iberian market).

Although the clearing algorithm supports the full suite of order formats, the local power exchanges do not. At present, only OMIE is supporting sophisticated orders such as MIC, consistent with the legacy formats in the Iberian market. In North West Europe, we understand the local power exchanges are in the process of rolling out ‘smarter’ block formats but have no immediate plans to support the sophisticated orders. In GB, for example, N2EX is planning to introduce profile, flexible and exclusive block products on 8 April 2014. The table below summarises the supported order types for a number of power exchanges.

Table 3-1 Order types supported by selected exchanges

Order type	EPEX Spot (Germany, France, Austria, Switzerland)	Nord Pool Spot (Norway, Sweden, Denmark, Finland)	N2EX (GB)	OMIE (Spain, Portugal)
Simple (hourly)	✓	✓	✓	✓
Regular Block	✓	✓	✓	✓
Linked Block	✓ (new)	✓	✓	✗
Profile Block			✓ (new)	✗

¹²SEM-14-008, paragraph 8.4.12

¹³ The COSMOS algorithm utilised for coupling Germany, France and Benelux since November 2010

Order type	EPEX Spot (Germany, France, Austria, Switzerland)	Nord Pool Spot (Norway, Sweden, Denmark, Finland)	N2EX (GB)	OMIE (Spain, Portugal)
Flexible Block		✓ (new)	✓ (new)	✗
Exclusive Block	✓ (new)		✓ (new)	✗
MIC	✗	✗	✗	✓
Scheduled Stop	✗	✗	✗	✓
Load Gradient	✗	✗	✗	✓

Further analysis will be required to assess the minimum sub-set of order formats that SEM generators may require to manage their unit commitment decisions in a mandatory DAM. It may be possible, for example, to achieve similar outcomes using either MIC orders or linked block profiles (assuming the current SRMC bidding principles are relaxed).

Of the power exchanges currently using Euphemia, only OMIE in the Iberian market requires unit-based offers and bids. The other exchanges all operate on a trading portfolio basis, with participants then responsible for converting the portfolio-based DAM results into unit-based generation schedules for nomination to the TSOs.

As discussed in the previous section, the Iberian DAM is voluntary and generators do have the ability to self-schedule bilateral contracts. The 'Mandatory Centralised Market' I-SEM HLD option, as proposed, is therefore likely to be without precedent in relying exclusively on Euphemia to directly formulate day-ahead generation schedules.

3.2. Incorporating generator constraints

The Euphemia algorithm supports a wide range of order formats, which could be considered as proxies for the sets of Commercial Offer Data and Technical Offer Data currently submitted by SEM generators to the scheduling algorithm. However, the Euphemia proxy formats do not map precisely to current SEM parameters, and in many cases may result in the transfer to generators of risks managed by the centralised SEM algorithm today. For example, consider generator minimum on time and start costs:

- ▶ The duration of a block bid could be used in Euphemia to reflect a minimum on time constraint. For a regular block bid, the generator will need to pre-determine the hours of the day to which the block applies, whereas this would be effectively be optimised for the generator under the current SEM algorithm.
- ▶ The fixed term of a MIC order could be used in Euphemia to represent a start cost that a generator would need to recover over its hours of operation in order to break-even. However, unlike the current SEM pricing algorithm, Euphemia does not include an Uplift component within market price formation to incorporate start costs or MIC parameters. Generators would therefore need to internalise the recovery of start costs by increasing their hourly offer prices (above variable cost levels).

SEM generators preparing their day-ahead submissions to Euphemia would not be alone in bearing responsibility for managing these risks. Generators in other European markets are typically responsible for internalising technical and commercial constraints within their pricing and scheduling decisions. However, under HLD Option 3, SEM generators could well be in the unique position of relying exclusively on Euphemia to formulate day-ahead generation schedules.

With SEM generators obliged to manage their unit commitment risks within a mandatory DAM framework, there is the potential for increasingly volatile pricing and scheduling outcomes as generators dynamically refine their bidding strategies day-by-day.

3.3. Solving the algorithm

To solve the market coupling problem, Euphemia runs a combinatorial optimisation process¹⁴. The main objective of the algorithm is to maximise the social welfare of the day-ahead market solution, namely the sum of consumer surplus, producer surplus, and congestion rent.

The presence of complex orders (such as 'kill or fill' blocks or MIC orders) requires the introduction of integer decision variables in Euphemia. Similar considerations apply to the treatment of generator Minimum Stable Levels in the current SEM algorithm.

Euphemia uses a branch and bound technique to find the best feasible solution until a stopping criterion is met. One stopping criterion is a maximum time limit (indicatively set at 10 minutes) to find a solution. It should be noted that solution time is likely to be a key binding limitation on Euphemia due to the requirement to publish results for all coupled regions.

Complex orders can only be either executed fully, or rejected fully. This constraint can result in some complex orders being rejected even if they are in the money. In outlining the solving methodology, the Euphemia public description states that:

- ▶ The 'cutting plane' methodology will reject some block orders that are in-the-money, but with special attention paid to avoid rejecting 'deep-in-the money' orders.
- ▶ To avoid accepting complex orders that do not satisfy their minimum income condition, the 'cutting plane' methodology will reject complex orders that will most likely not fulfil their minimum income condition.

The public description document does not quantify the parameters used to identify 'deep-in-the-money' orders or the criteria for assessing which MIC orders are likely to be satisfied. SEM generators are likely to want clarification on these points, particularly if the mandatory DAM HLD option is highly reliant on generators using sophisticated offer formats in Euphemia to manage unit commitment decisions.

At present, the price-setting segment of the SEM generation market is characterised by a flat supply curve due to the number of CCGTs with similar costs that are potentially at the

¹⁴Our understanding of the Euphemia algorithm is based on the November 2013 public description, https://www.n2ex.com/digitalAssets/89/89745_euphemia---public-description---nov-2013.pdf

margin. The handling of complex orders in a mandatory DAM will therefore be critical for both individual SEM generators and the wider market:

- ▶ CCGTs generators may find their complex orders rejected despite apparently being in-the-money;
- ▶ Any volatility in DAM pricing and scheduling resulting from the treatment of marginal complex orders will influence market dynamics in other timescales.

In particular, marginal generators may be unwilling to strike financial forward contracts with retailers if there is a perception of scheduling risk in the I-SEM DAM. This is because they will face exposure to basis risk if they are not scheduled to run despite bidding below the market clearing price.

In addition to these commercial concerns, SEM generators will also need to be confident that Euphemia will deliver a technically feasible market schedule under the 'Mandatory Centralised Market' HLD option. This raises the question as to whether the nominations submitted to the TSO are expected to precisely match the DAM positions or be consistent with technical plant parameters (e.g. ramp rates, minimum on times).

To the extent that generators are not able to precisely match their contractual and physical schedules, our working assumption is that the TSO would expect to receive a technically feasible schedule. This ensures the TSO will have a meaningful baseline from which to issue redispatch instructions for energy or system balancing actions. However, it is unclear how this would be achieved under the mandatory DAM HLD Option 3, with nominations passed directly from the market coupling solution to the TSO. Euphemia does not replicate the full set of Technical Offer Data supported by the current SEM algorithm, and so it is conceivable that Euphemia will not always provide technically feasible generation schedules. The balance of responsibilities between participants and the TSO for resolving any resulting mismatches will need to be clarified under the mandatory DAM HLD option, together with any associated exposure to imbalance costs.

If SEM generators face imbalance costs as a result of the inability to accurately reflect technical constraints in the day-ahead scheduling algorithm, these risks are likely to be reflected back in DAM offer prices. Ultimately, this may increase the volatility of pricing and scheduling outcomes in the mandatory DAM.

3.4. Algorithm stability and performance

Historically, many power exchanges have placed limitations on the number and size of block orders and other complex bidding formats. These limitations can help ensure the market clearing algorithm reaches a timely and feasible solution.

Our understanding is that the Euphemia algorithm does not limit the number or size of complex orders, but that the local power exchanges have continued to impose limitations since the introduction of NWE market coupling. Table 3-2 below shows the current limitations on regular block orders for a number of exchanges in the NWE region.

Table 3-2 Limitations on regular block orders

Exchange	Region	Max Block Bid Volume	Max Number of Block Bids (per portfolio)
EPEX Spot	Germany, Austria,	400 MW	100
	France,	400 MW	40
	Switzerland	100 MW	30
Nord Pool Spot	Nordic	500 MW	50
N2EX	GB	500 MW	80

As shown by Table 3-3 below, many exchanges appear to have taken a prudent or conservative approach regarding limits on the newer, more complex block products supported by Euphemia. Notably, N2EX has been required to tighten the limits on its new block products shortly before launch, following a decision by the PCR Steering Committee. Moreover, as stated above, the sophisticated order formats used in the Iberian market have not been implemented by the NWE power exchanges.

Table 3-3 Limitations on complex block orders

Exchange	Region	Max Block Bid Volume
EPEX Spot	Germany, Austria, France, Switzerland	<ul style="list-style-type: none"> • Exclusive block orders limited to 3 Exclusive Groups per portfolio and market area combination • Linked block orders limited to 1 per portfolio and market area combination (with 1 child per parent block)
Nord Pool Spot	Nordic	<ul style="list-style-type: none"> • Flexible orders limited to 5 per portfolio
N2EX ¹⁵	GB	<ul style="list-style-type: none"> • Exclusive block orders limited to 3 Exclusive Groups per portfolio • Flexible orders limited to 3 per portfolio
APX	Netherlands, GB	<ul style="list-style-type: none"> • Exclusive block orders limited to 5 Exclusive Groups per member • Linked block orders limited to 5 Linked Families per Member (with 3 levels of depth and 7 block orders per Linked Family)

The 'Mandatory Centralised Market' HLD option implicitly assumes that SEM generators will be able to utilise complex block products and sophisticated orders *without limitation* to reflect their commercial and technical parameters. This assumption will need to be rigorously tested given that the majority of European power exchanges have elected to limit the use of complex orders, in order to safeguard algorithm performance.

To illustrate why power exchanges are concerned with the potential impact of complex orders, Box 2 describes an incident in August 2013 which resulted in the failure of the Nord Pool DAM algorithm (this algorithm has now been replaced by Euphemia).

¹⁵ Following a decision by the PCR Steering Committee, N2EX was required to tighten the limits on the new block products being launched on 8 April 2014 (limits for flexible and exclusive orders reduced from 10 to 3). N2EX has stated that further testing will be required to deliver the new products as previously intended.

Box 2: DAM algorithm failure with complex orders

On 4 August 2013, the Elspot price calculation for the following day failed, and the prices and volumes of the previous working day (Friday 2 August) were used for delivery on Monday 5 August. The (legacy Elspot) algorithm's handling of flexible hourly orders with prices near the resulting System and Area prices was identified as the source of the problem.

In response, Nord Pool Spot decided to suspend the use of the flexible product pending a satisfactory resolution of the product's handling by the algorithm. Back testing with the new Euphemia algorithm successfully handled the flexible hourly orders for the day of the incident.

The incident increased the focus on the fall back procedures applying if the DAM algorithm failed to solve. It also highlighted the ongoing need for periodical stress tests of the clearing algorithm as market and bidding behaviour evolves.

From the perspective of the 'Mandatory Centralised Market' I-SEM HLD option, it can be noted that the Elspot DAM is voluntary and so market participants potentially had alternative trading opportunities on the day of this incident.

In the case of the I-SEM, a potential stress scenario would be a day of relatively low demand or high wind, with a high concentration of marginal plant using complex orders. One risk would be that the Euphemia algorithm fails to find an acceptable solution within the time limit, leading to the SEM temporarily decoupling from other markets. Stress scenarios such as this will need to be rigorously tested, particularly under a HLD that imposes mandatory participation in the DAM.

3.5. Testing the algorithm

The Euphemia algorithm has been extensively tested prior to implementation for NWE coupling and the Iberian market in February 2014.

A public presentation¹⁶ from April 2013 describes the dimensions of a testing process using actual 2011 daily order books:

- ▶ 44 bidding areas
- ▶ 55 interconnector lines
- ▶ 1250 regular block orders
- ▶ 10 flexible and 10 linked block orders
- ▶ 80 complex orders (OMIE - Iberia)
- ▶ 40,000 merit orders (GME - Italy)

¹⁶ Euphemia: Description and functioning (22 April 2013)
http://www.eirgrid.com/media/PCR_EUPHEMIA_CLARIFICATION.pdf

Another report from Nord Pool Spot¹⁷ describes tests for the NWE region using historical data covering:

- ▶ 27 bidding areas
- ▶ 38 interconnector lines
- ▶ 1800 block orders (per day)
- ▶ 6.2 TW average submitted quantity (per day)

Having spoken with market operators to research this paper, we understand that regression tests have been conducted using multiple years of historical data, and that algorithm performance has also been tested under forward-looking scenarios with increased volumes and greater take-up of complex order formats.

Based on the testing already conducted and the successful implementation of the algorithm to date (albeit for less than two months), we can be reasonably confident of the following:

- ▶ Euphemia is scalable for additional markets and increased trading volumes;
- ▶ Euphemia can successfully clear small pricing areas (some pricing zones in Nord Pool are smaller than the SEM, for example);
- ▶ Euphemia can handle sophisticated orders (e.g. MIC in the Iberian market).

From a SEM perspective, however, we suggest that Euphemia testing should focus on the combination of sophisticated order formats and a small pricing area with limited interconnection. This is unlikely to have been a key focus in terms of testing the Euphemia algorithm to date, given that the Nord Pool participants in relatively small pricing areas will not have utilised sophisticated order formats. Under the 'Mandatory Centralised Market' HLD option, the majority of SEM thermal generators may use sophisticated order formats. The high proportion of generators using complex orders, together with the large unit size relative to demand, is likely to distinguish I-SEM dynamics from those of the Iberian market.

Testing of Euphemia for I-SEM implementation should investigate potential impacts at both the market and generation unit level, including:

- ▶ Performance under stress scenarios and likely frequency of decoupling if not feasible;
- ▶ Volatility and general level of pricing outcomes if utilising a high proportion of sophisticated order formats;
- ▶ Likely frequency of paradoxically rejected complex orders (rejected in-the-money orders), especially for marginal CCGTs;
- ▶ Consistency of market schedules with plant technical characteristics.

¹⁷ Nord Pool Spot presentation (3 October 2013)
http://www.fingrid.fi/fi/yhtio/yhtioliitteet/Eur_asiat/NPS%20esitys%20Luoteis-euroopan%20integraatio%20v1%200.pdf

3.6. Euphemia governance arrangements

The Euphemia algorithm has been developed to date by the group of power exchanges participating in the Price Coupling of Regions (PCR) initiative. In principle, modifications to the algorithm could be incorporated to facilitate its implementation in the I-SEM.

Under the present governance arrangements, change request documentation would need to be prepared by the PCR Algorithm Working Group (representing all the power exchanges) with a final decision on whether to proceed with a proposal taken by the PCR Steering Committee. Going forward, it is envisaged that the governance of the day-ahead and intra-day coupling algorithms will be established according to rules and guidelines set out in the Network Code on Capacity Allocation and Congestion Management (CACM). The current draft of the CACM Network Code provides for a number of committees with power exchange, TSO and stakeholder representation to oversee the development and maintenance of the algorithms, systems and procedures for market coupling.

As we have noted above, only the Iberian market currently applies Euphemia to manage unit-based bidding and sophisticated order formats. Outside of Iberia, the development focus for the algorithm has been driven by markets with portfolio-based bidding. It is therefore uncertain whether any modifications to facilitate unit-based bidding by SEM participants in a mandatory DAM would be widely supported by other European stakeholders.

3.7. Summary

The I-SEM HLD Option 3 relies exclusively on the Euphemia coupling algorithm to directly formulate day-ahead generation schedules. All of the European markets which have implemented Euphemia to date provide alternative routes to market, including allowing participants to self-schedule generation. The success of the mandatory DAM proposal will be dependent on SEM generators being able to manage unit commitment with complex or sophisticated order formats in Euphemia. However, the power exchanges participating in NWE market coupling have limited the size and number of complex orders in order to safeguard the performance of the coupling algorithm.

In a mandatory SEM DAM, we envisage that the majority of thermal generators would seek to reflect their technical and commercial constraints using complex or sophisticated order formats. Extensive use of complex order formats by marginal or 'at-the-money' resources can prove problematic for market clearing algorithms, as was illustrated by an incident in August 2013 when the legacy Nord Pool algorithm was unable to set a clearing price due to the handling of complex orders. Although back-testing has shown the new Euphemia algorithm would have successfully handled this particular incident, it is unlikely that Euphemia has been rigorously tested under potential I-SEM stress scenarios: namely, a small market with limited interconnection and a high proportion of large units using sophisticated order formats.

One consequence of generators using complex orders is that their order may be rejected despite being in the money. This may influence the dynamics of hedging and pricing in the forward markets, with marginal generators potentially unwilling to strike financial forward contracts if there is a perception of scheduling risk in the I-SEM DAM.

4. CONCLUSIONS

The 'Mandatory Centralised Market' I-SEM HLD option differs from the prevailing design in other European markets by relying exclusively on the Euphemia coupling algorithm to directly formulate day-ahead generation schedules. Most European power exchanges operate voluntary day-ahead markets with portfolio bidding arrangements.

There are parallels between this HLD option and the Iberian market, which has implemented Euphemia with unit-based bidding and support for sophisticated offer formats to help generators manage scheduling risks. However, participation in the Iberian DAM is voluntary, and generators therefore have an alternative route to market with the option to self-dispatch to meet physical bilateral contract commitments.

The mandatory DAM proposal is reliant on SEM generators being able to manage unit commitment with complex or sophisticated order formats in Euphemia. To date, only the Iberian market has supported sophisticated orders, and the thermal plant utilising these order formats represent a much smaller proportion of the overall market than would be expected in the SEM. It should also be noted that other European power exchanges have placed limitations on the size and number of complex orders in order to safeguard the performance of the coupling algorithm.

A potential risk for generators using complex orders is that their order is rejected despite being in the money. This risk is heightened for marginal generators, and may therefore influence the dynamics of hedging and pricing in the forward markets.

Thus, while the Euphemia algorithm theoretically may have the functionality to support a mandatory DAM in the I-SEM, there has been no observable evidence to date to support the feasibility of the proposed approach. We therefore recommend rigorous testing of the algorithm is conducted prior to any decision to proceed with HLD Option 3. Testing should be focused on verifying the performance of the algorithm in a relatively small market with a high proportion of large units making extensive use of sophisticated offer formats.

Given the potential risks and concerns with the mandatory DAM approach and the likely time restraints on completing rigorous testing of a mandatory day-ahead scheduling process using Euphemia, HLD Option 1 may present a lower risk implementation pathway for the I-SEM programme¹⁸. A bilateral design would be consistent with the prevailing design in other European markets and provide a fall back mechanism, allowing SEM generators to self-dispatch in the event that the use of sophisticated order formats proved unsatisfactory.

¹⁸ Assuming appropriate liquidity and market power mitigation measures in the forward and spot timescales, as would also be required under Option 3.

Appendix 4 – NERA Report entitled “ The Capacity Remuneration Mechanism in the SEM”



The Capacity Remuneration Mechanism in the SEM

Prepared for Viridian

4 April 2014

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Executive Summary

On 5 February 2014, the Regulatory Authorities (RAs) of the all-island electricity market published a Consultation Paper laying out proposals to reform the Single Electricity Market (SEM).¹ This Consultation Paper (the “SEM Consultation”) considers proposals to reform the nature and scope of energy trading arrangements within the SEM, and also reviews different options for reforming the Capacity Remuneration Mechanism (CRM) used to remunerate generating capacity.

Viridian has asked us to consider the RAs’ proposals to reform the CRM that currently applies throughout the all-island market. In particular, we were instructed to consider the alternative options proposed by the RAs, and to address some specific questions about the design of CRMs in general.

Electricity Market Problems

We are conscious that a perfectly competitive electricity market (an “energy-only” market that puts a market-clearing price on all sales of electricity) will encourage efficient investment in capacity and will secure generator adequacy. Discussion of CRMs therefore begins by observing how an electricity market departs from this ideal form, and identifying a solution that mitigates the ensuing problems.

If every consumer had a smart meter offering information on half-hourly electricity prices, they could choose what quality of supply they wanted to receive or the maximum price they were prepared to pay. In practice, consumers (the “demand side” of the electricity market) do not participate fully, due to the technical difficulty and cost of doing so. Instead, if demand ever exceeds the available supply, the system operator decides when and where to cut off consumers’ demand in blocks (“load shedding”). Generator adequacy therefore possesses some characteristics of a “public good”, which leads to under-provision of a good or service unless a central authority intervenes.

The intervention required to encourage efficient investment in generator capacity² can be as simple as putting a high price on electricity (the “Value of Lost Load” or VOLL) whenever load is actually shed. However, whilst the political process might put a high price on load shedding, experience suggests a tendency for regulatory and political authorities to cap actual electricity prices below VOLL (explicitly or implicitly). This tendency may be driven purely by short term political considerations, but it also reflects the difficulty of distinguishing between a genuine shortage of capacity and anti-competitive behaviour. Many regulators have concluded that their electricity markets are not sufficiently competitive to allow

¹ The all-island electricity market is jointly regulated by the Commission for Energy Regulation (CER) in the Republic of Ireland and the Utility Regulator (UR) in Northern Ireland. Together, they constitute the Regulatory Authorities that oversee the Single Electricity Market.

² In discussing electricity markets, it is conventional to refer to “capacity” and “generator capacity” as if they were interchangeable. In principle, “capacity” can and should include “demand-side measures”, i.e., load shedding arranged on a commercial basis. In practice, the extent of demand-side measures is limited by technology (the need to cut off all a consumer’s demand, rather than fine-tuning their consumption) and/or cost (the time, money and effort required to liaise with a consumer over which forms of demand to sacrifice at what price levels).

unfettered rivalry between generators. If any generators have a large market share, regulators may put an explicit cap on prices, to prevent excessive pricing. If any large generator is state-owned, its competitors may suspect it of acting in a non-commercial manner. In response, regulators may regulate the formation of generators' offers to the market, thereby implicitly capping electricity prices.

In any case, the mere threat of such interventions in electricity pricing is enough to reduce the expected long run revenue from generation. That deters investors from building enough generation capacity and requires some other mechanism to provide the "missing money".

These problems are compounded in electricity markets that are small relative to the minimum size of investment in generator capacity. Any single investment can turn a capacity shortage with very high prices into a capacity surplus with very low prices. Investors may therefore wait until a shortage is particularly acute before they invest, to avoid causing prices to collapse. Coordinating such a strategy across all potential investors is difficult, especially if liquid forward markets do not emerge. The possibility of over-investment acts as a further deterrent to investment.

The RAs have identified these and similar concerns when deciding how the all-island electricity market should work. In 2007, when the market was set up, and again when the RAs conducted a Medium Term Review between 2009 and 2011, they concluded that the small size of the market, the market power of dominant companies, and the inherent regulatory/political risk would all deter efficient investment in generator capacity. The solution adopted then was to include a Capacity Remuneration Mechanism within the SEM. These particular problems have not disappeared since the RAs last looked at the electricity market, which implies that some form of CRM is still required. The RAs would therefore need strong arguments to support a decision to remove the CRM now, to persuade investors that conditions had changed, and that the decision was not driven purely by short term political considerations. Otherwise, the RAs would inject new and additional regulatory risk into investors' perceptions of the all-island market, with adverse consequences for investment and consumers' interests.

The RAs use the alleged incompatibility of the existing CRM with the EU Target Model as a reason for reviewing its design. In practice, it may not be necessary to redesign the CRM fundamentally to make it compliant with the Target Model. It may be sufficient simply to replace the *ex post* component of the capacity payment with an *ex ante* component, or to exclude interconnectors from the mechanism.

Important Factors in Any Evaluation of Options for the CRM

The SEM Consultation discusses seven "options" for a future CRM in the all-island market. Those options are:

- 1: "Strategic Reserve"
- 2a: "Long Term Price Based"
- 2b: "Short Term Price Based"
- 3: "Capacity Auctions"
- 4: "Capacity Obligations"

- 5a: “Centralised Reliability Options”
- 5b: “Decentralised Reliability Options”

The “strategic reserve” differs from the other options, as it would “target” any payment for capacity on a few selected generators, rather than making a “market-wide” payment to all available capacity.³ Such schemes might help to increase or to maintain the level of “flexible capacity”, which is useful for meeting the system operator’s statutory duty to operate the electricity system securely from minute to minute and hour to hour. However, strategic reserve does not contribute to generator adequacy, since the capacity it supports simply displaces or “crowds out” investment in other capacity.

We understand that the system operator might wish for a strategic reserve, because the growing volume of intermittent generation from renewable energy sources is increasing the hourly fluctuations in output from dispatchable plant. However, such considerations concern short term “operating reserve”, not the provision of adequate generator capacity to meet demand in the long term. In a competitive market, long term security of supply is not the responsibility of the system operator, but it is of direct interest to consumers and to the regulator (acting on behalf of consumers). Discussion of strategic reserves – or rather, short term operating reserves – should not be allowed to distract from consideration of generator adequacy.

This discussion highlights the need to set out clearly the reasons for having a CRM. Elucidating the reasons will also be important to ensure that the proposed CRM passes the scrutiny of the European Commission under the rules on State Aid. The current CRM was introduced with the aim of promoting investment in generator adequacy. Conditions in the SEM have not changed so radically since the last time the RAs reviewed it. The SEM still appears to face several of the problems that afflict electricity markets and make a CRM necessary:

- The market is small and open to abuse of market power by dominant producers;
- Investors receive imperfect signals from electricity prices, because of transactions costs (e.g., lack of demand side participation, and insufficient “granularity” of energy prices) and the lack of liquid forward markets;
- Prices still vary widely, so generator adequacy suffers from the “missing money” problem owing to a variety of actual and threatened interventions in the market. These interventions include explicit price caps, regulation of generator bidding, and regulatory and political interventions that deny generators the opportunity to recover their costs.

The options in the SEM Consultation are not spelled out in enough detail to permit a full evaluation at this stage. However, no proper evaluation or selection process could be carried out without giving consideration to these key factors. For example:

³ Available capacity eligible to receive a market-wide CRM includes generation fired by fossil fuels, but also renewable capacity receiving separate support under environmental policies, to the extent that renewable capacity relies on revenue from sales of energy and capacity to cover its total costs.

- The “price-based” options (2a and 2b) will have to take into account the instability of a small market and the need to remedy problems of market power, so in practice they are likely to incorporate a demand curve (price-quantity trade-off).
- The “quantity-based” options (3 and 4) are also likely to incorporate a price-quantity trade-off, for exactly the same reasons. In this respect, the “price-based” and “quantity-based” options will be very similar. However, the “price-based” options offer a real-time or *spot price* for capacity. In contrast, the “quantity-based” options comprise a kind of *forward contract* for capacity, with a penalty for non-delivery imposed in real time (rather like a spot price). Designing a quantity-based forward contract for capacity raises all the same questions as a price-based CRM (such as the definition of eligible capacity). Any CRM (whether it includes penalty arrangements or not) will require a compliance mechanism (such as forced testing).
- In addition, setting up forward contracts (i.e., quantity obligations) in advance would create a need for market participants to trade their obligations, if their available capacity or capacity obligation change over time. Such trading may be inefficient in a market dominated by a single market participant (especially one that is not subject to commercial pressures). However, if suppliers cannot buy and sell capacity obligations efficiently, they will find it difficult or impossible to compete for new customers. Problems in a secondary market for capacity obligations will therefore hinder competition in the retail electricity market.
- Finally, as specified in the SEM Consultation, the “reliability options” (5a and 5b) appear to be nothing more than long term electricity contracts settled financially (“contracts for difference”) against an electricity market reference price. It is not clear what problem these options are intended to solve. For instance, they would not be expected to offer any more revenue than is available from the electricity market, so they do not contribute any of the “missing money”. We note that early versions of the Electricity Market Reform (EMR) in Britain discussed a similar form of contract. However, the latest EMR proposals impose an additional penalty for non-delivery (closer to the concept of VOLL) over and above the electricity price.

From these observations, we conclude that the SEM Consultation has not specified the options for any future CRM in sufficient detail to allow a full evaluation of them. We conclude also that any future evaluation would have to take into account a number of important factors specific to the all-island electricity market, to ensure that it serves not just administrative requirements, but also the interests of consumers.

1. Introduction

1.1. Overview

On 5 February 2014, the Regulatory Authorities of the all-island electricity market (the CER and UR), published a consultation paper laying out proposals to reform the Single Electricity Market (SEM).⁴ The “SEM Consultation” considers proposals to reform the nature and scope of energy trading arrangements within the SEM, and reviews different options for reforming the Capacity Remuneration Mechanism (CRM) used to remunerate generating capacity.

Viridian asked us to consider the RAs’ proposals to reform the CRM that currently applies throughout the all-island market. In particular, we are instructed to consider the alternative options proposed by the RAs, and to address some specific questions about the design of CRMs in general.

1.2. Our Instructions

Viridian asked us to:

- describe the requirements set out by the European Commission on the compatibility of CRMs with state aid guidelines; and
- review the options proposed by the RAs for a new CRM, setting out the minimum requirements for evaluating the different options.

To support this review, Viridian asked us to consider the reasons for having a CRM and the conditions affecting its design in greater detail. We therefore:

- outline the conditions in which it would be economically efficient to have a CRM, rather than relying on an “energy-only” market (such as demonstrable and irremediable market failures in the energy-only market), thereby identifying the economic criteria for assessing whether a CRM is necessary; and
- review the case for a CRM in Ireland, in the light of the underlying economics of the system and the requirements set out by the EC and ACER, focusing on whether the specific characteristics of the Irish electricity system (noting the projected surplus capacity out to 2022) provide good reason for instituting a CRM from the standpoint of economic efficiency and the EC’s guidelines.

In addition, on the assumption that considerations of economic efficiency justify the adoption of a CRM, Viridian asked us to propose solutions for key choices in the high-level design of a CRM that meet the economic criteria and are likely to comply with European-level guidance.⁵ We set out the questions put to us by Viridian in Appendix B.

⁴ **I-SEM – High Level Design** (2014), *Integrated Single Electricity Market (I-SEM) – High Level Design for Ireland and Northern Ireland From 2016*, Consultation Paper, SEM Committee, SEM 14-008, 5 February 2014.

⁵ Our review of this point will only consider economic interpretations of these guidelines and will not constitute legal advice.

1.3. The Structure of This Report

This report proceeds as follows:

- Chapter 2 provides the background and context to the review of the CRM in the SEM, including the EC State Aid guidelines;
- Chapter 3 gives an outline of the role of a CRM in the Irish market, and answers some questions about its future design;
- Chapter 4 sets out criteria against which to evaluate the options put forward by the RAs;
- Chapter 5 uses these criteria to set out the minimum requirements for evaluating each of the RAs' options;
- Appendix A provides detailed arguments on the role of a CRM in the Irish market; and
- Appendix B provides detailed answers to the high level design questions put to us by Viridian.

2. Background and Context

This chapter sets out the background relevant to both our review of the need for a CRM in Ireland and our comments on its eventual design. In particular:

- Section 2.1 sets out the context of the CRM in the all-island market;
- Section 2.2 describes the RA’s review of the CRM in the all-island market and sets out an overview of the RA’s views on the future of the CRM; and
- Section 2.3 sets out the constraints set out by the EC State Aid guidelines on the possible design of the CRM in the all-island market.

The current CRM has been in place since the creation of the SEM in Ireland in 2007, justified by, amongst other things, by a need to attract and retain investment in a small market. That investment is needed to meet peak demand, but the CRM is designed to spread its cost over a wider range of periods, including some with a shortage of capacity and some with excess capacity.

The market is currently experiencing a period of excess capacity. According to the TSOs’ assessment, this excess capacity will last for some time, but that conclusion depends on the continuation of existing incentives within the SEM. The RAs’ review suggests that they are minded to retain a CRM (the question remains open for consultation), but that they believe the CRM must be adapted to comply with the EU Target Model. The EC State Aid guidelines set out high level criteria for justifying CRMs under state aid rules. These guidelines specifically require policymakers to explain the need for a CRM before intervening in the market.

2.1. The Context of the CRM in the All-Island Market

2.1.1. The SEM has included an explicit CPM since its creation in 2007

The Regulatory Authorities (the Northern Ireland Authority for Energy Regulation and the Commission for Energy Regulation, acting jointly) set up the Single Electricity Market (SEM) for the island of Ireland in November 2007. They decided to introduce an explicit capacity payment mechanism (CPM) to attract investment, rather than to rely on the implicit reward that generators receive in an energy-only market when prices rise above the short run marginal cost of production. During the design process, they explained the objectives of the CRM:

“This decision is driven by the need to attract timely investment, retain capacity and encourage efficient exit recognising specific characteristics of the all island market. Particularly, the scale of the market, the relative size of new investments and their impact on market dynamics and consequent uncertainty.”⁶

⁶ SEM – Proposed High Level Design (2005), *The Single Electricity Market – Proposed High Level Design*, SEM Committee, AIP/SEM/06/05, 31 March 2005, page 24.

The RAs subsequently comprehensively reviewed the CPM between 2009 and 2011 to assess its performance against its objectives. The RAs concluded that the CRM remained important to the SEM because of its impact on the financeability of generation projects, that the CPM was “generally working well and that there is no compelling need to make major changes to the current design”.⁷

The CPM operating in the SEM at present allocates an “annual capacity payment” determined by the RAs among all eligible generators participating in the market. It is funded by electricity suppliers.⁸ The annual payment is equal to a volume of capacity times the cost of building new capacity, specifically (1) the volume of capacity required to ensure a predetermined standard of security of supply *times* (2) the fixed cost per kW of the “Best New Entrant”, i.e. a peaking plant.⁹ This annual payment is split into twelve monthly “capacity period payments” of varying size. The larger payments fall in months where there is a higher expected loss of load probability (LOLP), and vice versa. These monthly payments are therefore greater during winter months of high demand than during summer months of low demand. Each monthly payment is divided among the available capacity in that month. The more capacity generators make available in total, the less they receive for each kW of available capacity. The current CPM therefore applies a trade-off between price and quantity.

Generators receive a share of the monthly “capacity period payment” for every half hour in which they are available to generate. The total payment to all generators in each half hour is determined by dividing the monthly “capacity period payments” into three components.¹⁰

- **“Fixed” (30 per cent):** this portion of the monthly payment is allocated across hours within the month in proportion to *ex ante* forecasts of demand.
- **“Variable” (40 per cent):** this portion of the monthly payment is allocated across hours within each month in proportion to *ex ante* forecasts of LOLP. *Ex ante* LOLP is determined in advance of each month by calculating generation margins, which are a function of forecast demand, registered capacity, scheduled outages and forced outages. LOLP is a decreasing function of generation margin.
- **“Ex Post” (30 per cent):** this portion of the monthly payment is allocated across hours within each month according to assessments of *ex post* LOLP. *Ex post* LOLP is determined after the end of each month by calculating generation margins as a function of actual demand and actual available capacity. The margin is then converted into a LOLP using the same function as for the *ex ante* component (although, after the fact, there is actually no probabilistic element to the loss of load).

⁷ CPM – Medium Term Review (2012), *CPM Medium Term Review*, Final Decision Paper, SEM-12-016, 6 March 2012, page 3.

⁸ CPM and Associated Input Parameter Decision Paper (2006), *The Capacity Payment Mechanism and Associated Input Parameters – Decisions Paper and Response to Detailed Comments*, SEM Committee, AIP-SEM-95-06, July 2006.

⁹ CPM and Associated Input Parameter Decision Paper (2006), page 26.

¹⁰ CPM and Associated Input Parameter Decision Paper (2006), pages 22-24.

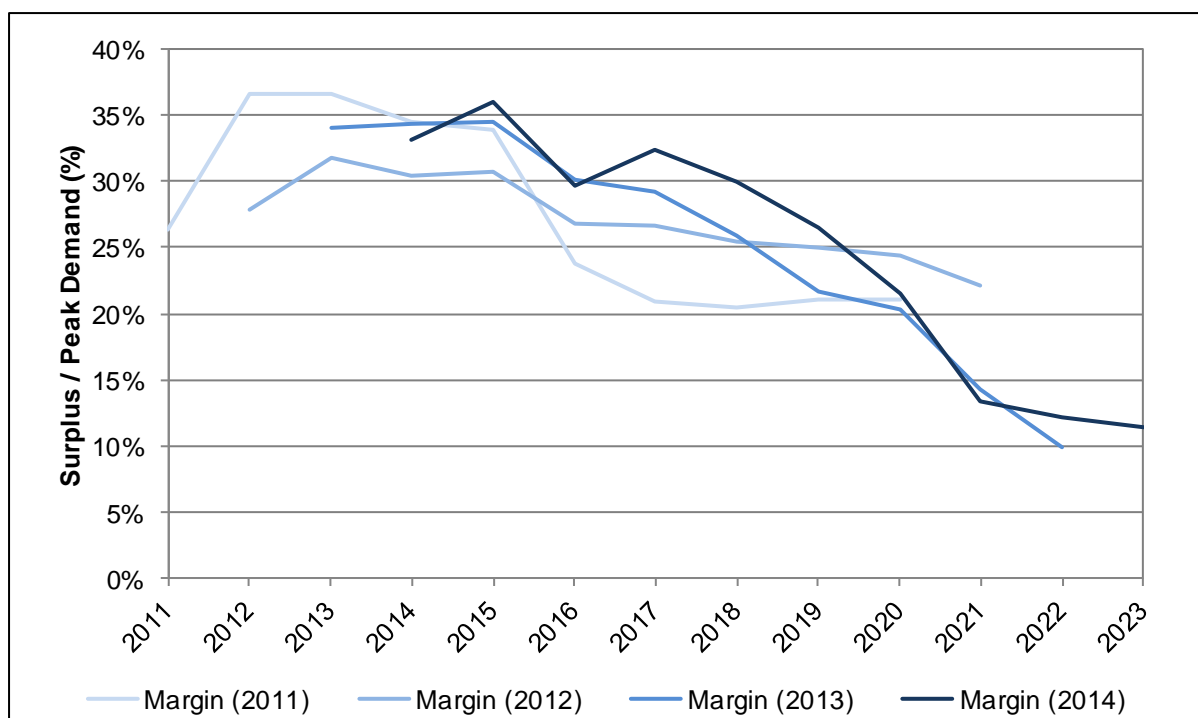
Some sources of generation in the SEM (namely energy flows across interconnectors and intermittent generators) receive half hourly payments that are proportional to their production of energy, rather than their availability. In the case of interconnectors, traders importing electricity receive a capacity payment, while traders exporting electricity must contribute towards the cost of capacity payments. Intermittent generators using renewable energy sources rely on revenue from energy sales and capacity payments, to the extent that other forms of support do not fully cover their costs.

2.1.2. Security of supply is forecast for the medium-term

The SEM currently has a large surplus of generating capacity which the system operators forecast to last until at least 2023, as shown in Figure 2.1. The system operators forecast that the reserve margin will tighten from a high of 35 per cent in 2015 to 12 per cent in 2023, as demand growth erodes excess capacity on the system. The most recent forecasts show a larger reserve margin for most of the period than at any time in the last four years, principally because forecast demand growth has been revised down over that time. Interconnector capacity has also increased: since 2002 the Moyle interconnector (450MW) linked Northern Ireland with Scotland; in May 2013 the East-West interconnector (500MW) established a second link between Ireland and Wales.

The actual levels of excess capacity that may materialise over the coming decade depend crucially on the redesign of the SEM. The system operators base their forecast of capacity on the existing stock of plant, less plant that has announced its retirement date. If the redesign of the SEM were to threaten the ability of existing plant to cover its costs, for example, by reducing the capacity payment, some plant may retire earlier than anticipated by the system operators. That might turn the forecast excess supply into an actual shortage. We discuss the implications of the current level of capacity on the objectives of the CRM in Appendix A.3.

Figure 2.1
Surplus Capacity Is Forecast To Continue



Source: Eirgrid, SONI (2011, 2012, 2013, 2014); NERA analysis.¹¹

To calculate generation margins, the Irish TSOs reduce peak demand by the amount of demand served by wind farms. This “wind capacity credit” corresponds to a varying load factor, of approximately 20 per cent for 1,000MW of installed capacity, decreasing to 10 per cent for 6,000MW of installed capacity.¹²

Thermal plant dominates electricity generation in the SEM. Figure 2.2 shows that, as of 2014, the SEM contains 1,331MW of coal-fired capacity, 5,260MW of gas-fired capacity and 1,503MW of oil-fired capacity.¹³ According to the TSOs’ forecasts, levels of thermal capacity are relatively stable – capacity from coal-, gas- and oil-fired plant is forecast to fall by only 4 per cent between 2014 and 2020. By contrast, intermittent generation is growing rapidly. Between 2014 and 2020 nominal wind capacity is forecast to grow by 65 per cent, from 2,840MW to 4,700MW.

The increase in intermittent generation from wind is likely to contribute to greater reliance on flexible thermal generation to balance supply and demand. As a proportion of installed

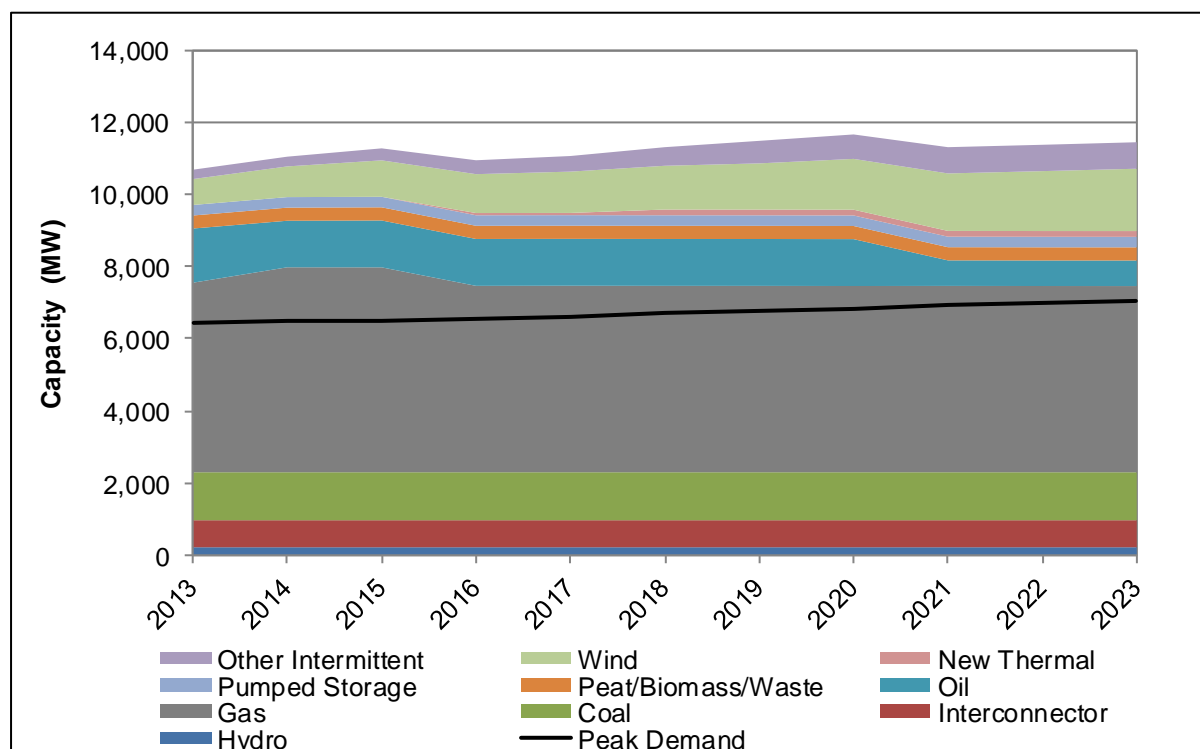
¹¹ Eirgrid, SONI, *Generation Capacity Statements* (passim.). The margins presented here are surplus capacity ÷ peak transmission demand.

¹² Eirgrid, SONI (2014), page 38.

¹³ These figures include capacity which can switch between fuel types. We have assumed that both the Moneypoint and Kilroot plants operate as coal-fired units.

capacity, generators defined by the TSOs as “non-dispatchable” or “partially dispatchable” are forecast to make up 82 per cent of the total in 2020, down from 90 per cent in 2014.¹⁴

Figure 2.2
Intermittent Generation Is Forecast To Grow As A Share Of The Capacity Mix



Source: Eirgrid, SONI (2014); NERA analysis¹⁵. Wind capacity is derated with a 30 per cent load factor.

2.1.3. Market Power and the CRM

The all-island electricity market is relatively concentrated by European standards. The Herfindahl-Hirschman Index (HHI) is a measure of market concentration, which ranges between 0 for a perfectly competitive market and 10,000 for a monopolised market. The all-island generation market has an HHI of 2,590, above the level (2,000) at which European rules suggest a merger of any two parties would raise competition concerns.^{16,17} Similarly, the supply market is also concentrated, with an HHI of 2,697.

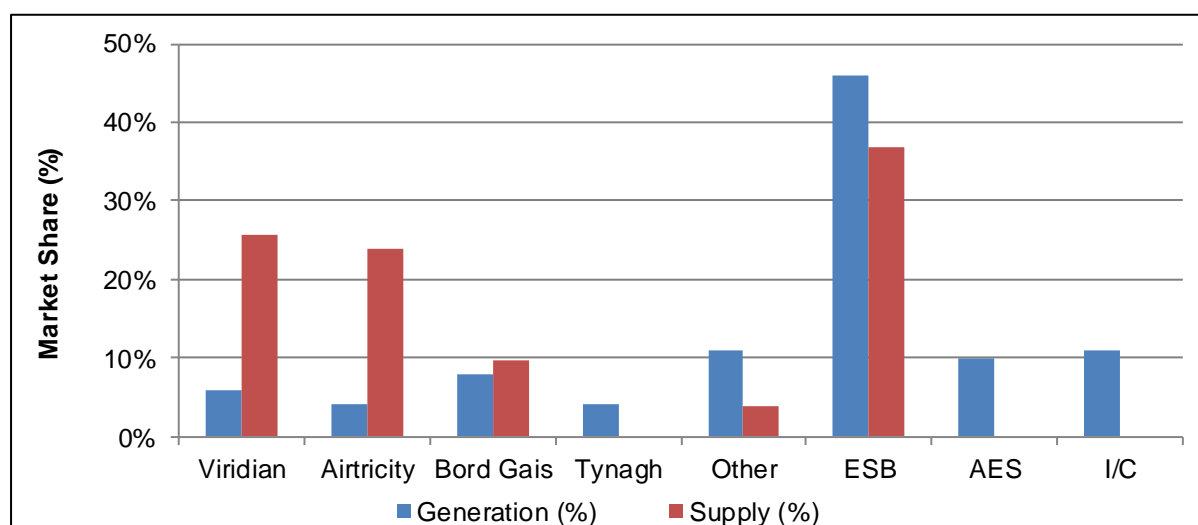
¹⁴ Both calculations and Figure 2.2 use an estimate of wind capacity based on the assumption of a 30 per cent load factor, for illustrative purposes.

¹⁵ Eirgrid, SONI (2014), *All-Island Generation Capacity Statement- 2014-2023*, Appendix 2, pages 63-64.

¹⁶ The EC merger guidelines state that industries with a post-merger HHI of above 2,000 and a delta (i.e., change in HHI) of above 150 may raise competition concerns. See *Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings*, Official Journal of the European Union, (2004/C 31/03), 5 February 2004, paragraph 20. US authorities define a “highly concentrated” market as one with a HHI greater than 2,500. See *Horizontal Merger Guideline*, Department of Justice and Federal Trade Commission, 19 August 2010, page 19.

The largest player in the all-island generation market is ESB, which accounted for 46 per cent of electricity output in 2013 (a market share that may indicate dominance, according to EU guidelines).^{18,19} The other large sources of electricity are interconnector flows (11 per cent), Bord Gais (8 per cent), and Viridian (6 per cent). The supply market is dominated by Electric Ireland (a subsidiary of ESB) which holds a 37 per cent share. The two other largest players are Viridian (26 per cent) and Airtricity (24 per cent). The balance between different players in the upstream and downstream market is illustrated Figure 2.3.

Figure 2.3
The All-Island Market Has One Large Player in Generation and Supply



Source: ESB (2014), NERA analysis. (I/C = Interconnectors)

Figure 2.3 shows that there are sizeable differences between the market shares in each segment. Both Viridian and Airtricity are major retail suppliers of electricity, but their upstream operations provide limited generation. Possible sources to make up this shortfall include independent generators like AES and energy traded over interconnectors (supplied through the gross pool). By contrast, ESB has a portfolio which generates more than enough electricity to meet the needs of its downstream customers. Since ESB is 95 per cent state-owned, it competitors face a risk that it responds to non-commercial incentives in the energy and capacity markets.

These imbalances between generation and retail supply do not affect the outcome of the current CPM in the all-island market, since the payment made to available capacity is determined centrally rather than by downstream market participants. However, the presence of (1) a dominant market player and (2) large imbalances in the supply and demand for

¹⁷ Market share figures on which this calculation is based are quoted are on a generation basis for 2013. Figures taken from ESB (March 2014), *Investor Presentation – 2013 Full-Year Results and Business Update*, pages 16-17.

¹⁸ *Guidance on the Commission's enforcement priorities in applying Article 82 of the EC Treaty to abusive exclusionary conduct by dominant undertakings*, Official Journal of the European Union, (2009/C 45/02), 24 February 2009, paragraph 14.

¹⁹ ESB (March 2014), *Investor Presentation – 2013 Full-Year Results and Business Update*, page 16.

capacity are important constraints when considering different designs for a CRM, especially those that rely on capacity markets and trading.

2.2. The SEM Committee's Review of CRMs under I-SEM

On 5 February 2014, the RAs announced a re-design of the SEM as part of implementing the EU Target Model. They call this new market the I-SEM. In order to comply with the EU Electricity Target Model by 2016, the regulators are consulting on reforming various aspects of the market, including its Capacity Remuneration Mechanism.

In their most recent statements, the RAs leave open the question of whether a CRM will still be necessary in the reformed SEM.²⁰ However, the RAs argue that the current mechanism is inconsistent with the Target Model. Cross-border flows across interconnectors receive a capacity payment based on electricity production, but the value of this payment is not known beforehand, due to the ex post component of the payment. The EC Target Model puts more emphasis on cross-border trading in day-ahead timescales, but the ex post component of the CRM appears to be a barrier to market coupling, as it prevents market participants from hedging risks and trading efficiently across borders based on observed price differentials. The RAs therefore state that “to include a capacity price in market coupling would require the capacity prices to be known ex ante (for cross-border trading)”.²¹ The RAs may decide to retain a CRM. If so, given the parallel proposals to reform energy trading arrangements in the SEM, they intend to reform the form and scope of the current all-island mechanism, to accommodate the requirements of the EU Target Model and to be compatible with EC guidelines on state aid.

2.2.1. The RAs are considering CRM options

In the SEM Consultation on the high level design of the reformed market, the RAs put forward a number of options for a future CRM. They set out five design attributes for categorising CRMs (see Figure 2.4):

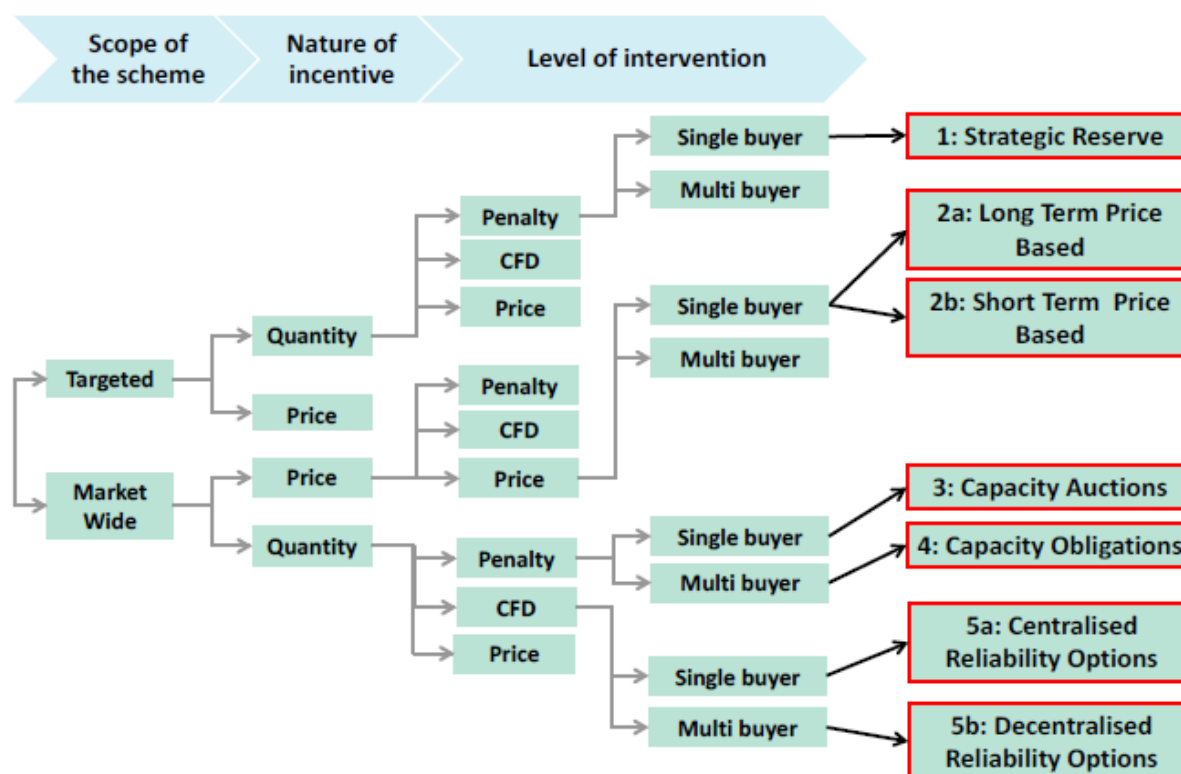
- **Scope:** whether the mechanism is targeted or market-wide.
 - Targeted mechanisms procure capacity that does not participate in the energy market (or does not participate unless prices are unusually high). The capacity is only used to address a shortage of capacity at times of system stress.
 - By contrast, market-wide mechanisms involve all generators and may include demand-side response, both of which are also free to participate in the energy market.
 - The RAs state that they consider capacity trades under targeted mechanisms (such as procuring strategic reserve) to have more limited “consequences [for] the wider energy market”, but have not investigated their effects in detail.²²

²⁰ I-SEM – High Level Design (2014), pages 5, 97.

²¹ I-SEM – High Level Design (2014), page 97.

²² I-SEM – High Level Design (2014), page 101.

Figure 2.4
The RAs Are Considering Five Options For A Reformed CRM



Source: I-SEM Consultation.²³

- **Nature of the incentive:** whether the CRM is based on price or quantity. The RAs’ division of CRMs into “price-based” and “quantity-based” mechanisms depends on how the obligation is defined and the method used to remunerate capacity.
 - According to the RAs, a price-based mechanism is any CRM where a value is “attached to capacity and included as an explicit element of the price paid to available generation/demand resources”.²⁴ It does not impose an obligation on generators to deliver capacity into the market, but rewards them for doing so. Within the RAs’ taxonomy, the current CRM in the SEM is an example of a price-based mechanism. The RAs’ definition of a price-based mechanism does not require the price for capacity to be constant. In the current CRM, the revenue for capacity is fixed, and the price per kW of capacity varies according to the quantity of capacity available.
 - Quantity-based CRMs place an obligation on the participant to ensure that adequate generating capacity (or demand reduction capacity) is delivered into the market. Such schemes may include a payment for fulfilling this obligation (or a penalty for failing to fulfil it), determined either administratively or through a market mechanism.

²³ I-SEM – High Level Design (2014), page 102.

²⁴ I-SEM – High Level Design (2014), page 102.

- **Timing:** whether the price signal provided by a CRM is visible in advance, or only *ex post*, and when the payments fall due.
 - Proposed CRMs in France and Great Britain provide a price signal four to five years in advance of delivery. By contrast, prices in the CRM in Ireland depend on annual reviews but are not fully known *ex ante*, because of the *ex post* component.
 - The RAs state that the distribution of capacity payments throughout the year should reflect any seasonality in the value of capacity. They argue that the current CRM system (which sets a fixed annual payment, but allocates more of it to periods where capacity is relatively scarce) allows for a balance between (1) “a short term signal to provide the required capacity during periods of tight capacity margin”, and (2) “the longer term certainty over capacity revenues for generators”.²⁵
- **Level of intervention:** whether the CRM involves setting an explicit capacity target, and what penalty arrangements accompany it. The RAs have stated that:
 - they intend to define centrally the target level of capacity, whether they adopt a price-based or quantity-based mechanism;
 - the obligation to procure this capacity (if any) may be placed either on the TSO, or on market participants in proportion to their share of peak demand; and
 - penalty arrangements (if any) may be either determined by the regulator, or through a market-based contractual approach.
- **Eligibility:** whether participation in the CRM is limited to generators participating in the local energy market, or includes generators located outside that market.
 - A key requirement for market coupling is to avoid distorting cross-border participation in electricity markets. Therefore the RAs have concluded that, to comply with the Target Model, “the SEM CRM would have to be set *ex ante* (rather than partially *ex post* as now)”.²⁶
 - It is not clear whether the RAs base their reasoning on statements made by the European Commission or on other principles of the EU Target Model. As a matter of economic principle, trade need not be “distorted” even if the value of capacity is only known *ex post*, as market participants can and will trade on the expectation of future revenues.
 - The target model requires *day-ahead* market coupling across Europe, but within-day trading of electricity is also feasible in some member states. Within-day prices in European electricity markets may not match day-ahead prices, if conditions change in the meantime. As a result, the flow of electricity from one market to another prompted by day-ahead prices (and market coupling) may not appear profitable from an *ex post* perspective. However, the source of the difference between day-ahead and within-day energy prices is the change in conditions, rather than any distortion or inefficiency. It is not obvious that within-day revisions to the price (or value) of

²⁵ I-SEM – High Level Design (2014), page 104.

²⁶ I-SEM – High Level Design (2014), page 107.

capacity are conceptually different from within-day revisions to energy prices, and may just reflect changing conditions.

- However, the *ex post* element of the CRM in Ireland may create a risk that is not be present in electricity markets in other member states, where the reward for capacity is fixed in advanced through energy trading or *ex ante* capacity mechanisms. As a result, traders will be unable to hedge certain risks of cross-border trading.

In practice, the RAs' taxonomy only refers to the major decisions that might fall within the remit of the RAs themselves. As Figure 2.4 shows, it only reduces the range of potential CRMs to a number of general approaches, each of which contains more than one possible design. The advantages and disadvantages of adopting any one approach (as defined by the RAs' taxonomy) will depend on the precise details of the proposed designs. Bearing in mind the limited information available at this stage, we set out in Chapter 3 a high-level appraisal of the options and the minimum requirements for the RAs' future evaluation of each option.

2.3. EC State Aid Rules

State Aid describes benefits granted through state resources, which favour certain undertakings or the production of certain goods, in a way that distorts (or threatens to distort) competition within the internal market, and that affects trade between Member States. The European Commission rules on State Aid for generation adequacy (currently in draft form) place limits on when market intervention using state resources, through CRMs, is justified.²⁷

The emerging EC rules require that any future CRM aimed at ensuring generation adequacy in the all-island market must meet the following criteria.²⁸

- **Objective of Common Interest:** a CRM must be aimed at a clearly defined generation adequacy problem. However, the EC notes that introducing a CRM may contradict the objective of phasing out subsidies to fossil fuel generators. The EC requires that Member States must first consider alternative means of ensuring generation adequacy, such as increased demand-side management and interconnector capacity.
- **Need for State Aid:** a CRM should not be used as a substitute for addressing deficiencies in the energy market, such as a lack of market coupling or an effective ancillary services market. In its assessment, the EC will consider whether demonstrable market or regulatory failures have given rise to a generation adequacy problem, citing the example of wholesale price caps. There is a presumption that Member States must take steps to remove these market failures before a CRM can be justified.²⁹

²⁷ **EC Draft Guidelines** (2013), (*Draft*) Paper of the Services of DG Competition containing draft Guidelines on environmental and energy aid for 2014-2020, European Commission, Competition DG, 18 December 2013.

²⁸ **EC Draft Guidelines** (2013), pages 55-58.

²⁹ See **EC Staff Guidance** (2013), *Generation Adequacy in the internal electricity market – guidance on public interventions*, Working Document, Commission Staff, SWD(2013) 438 final, 5 November 2013, page 16: “Member States are encouraged to identify and, where possible, remove regulatory and market failures [...] before intervening in the market. In particular [...] the removal of wholesale and retail price regulation [...] has an important role to ensure generation adequacy”.

- **Appropriateness:** a CRM should remunerate solely the provision of capacity available to generate electricity, and not the sale of electricity. A CRM should allow different technologies, with different lead times, to meet the need for generation adequacy. However, State Aid “should in principle not reward investments in generation from fossil fuel plants unless it can be shown that a less harmful alternative to achieve generation adequacy does not exist”.³⁰
- **Incentive Effect:** a CRM must incentivise the “beneficiary to change its behaviour ... which it would not do without the aid”, and not merely subsidise activities generators would undertake regardless.³¹ The EC suggests the incentive effect can be identified by comparing levels of activity with and without intervention – it cites the example of examining the NPV of investment with and without aid.³²
- **Proportionality:** a CRM must result in its beneficiaries earning a rate of return which is “considered reasonable”.³³ The EC advocates a “bidding process on the basis of clear, transparent and non-discriminatory criteria” to ensure this outcome, noting it must be open to existing and new generation.
- **Avoidance of Negative Effects:** a CRM must be designed in such a way that any capacity can participate if it is able to address the generation adequacy problem, including different technologies and operators in different Member States. The CRM should be designed to allow a sufficient number of generators to participate “to establish a competitive price for the capacity”, and should not impose negative effects on the internal market such as export restrictions.³⁴ In addition (in a departure from the general rules on competition and state aid), the EC guidelines suggest that any CRM should favour low carbon generators when they are technically and economically equivalent to alternative options.³⁵

Of the above criteria, the first two create an obligation to demonstrate that a CRM is needed to solve established market failures. We consider the implications of these criteria in the context of the all-island market in Appendix A. The following four criteria are concerned with the detailed design of a CRM that is compliant with the law on state aid. We address these criteria in our answers to the specific questions put to us by Viridian in Appendix B.

The State Aid guidelines rely on economic criteria such as identifying market failure as a means to establishing the need for a CRM. The clear lesson from the State Aid guidelines is that the economic conditions of the all-island electricity market are important to the design of any capacity payment and need to be considered in combination with any legal constraints.

³⁰ EC Draft Guidelines (2013), page 56, paragraph 212.

³¹ EC Draft Guidelines (2013), page 23, paragraph 55.

³² EC Draft Guidelines (2013), page 25, paragraph 66.

³³ EC Draft Guidelines (2013) page 57, paragraph 214.

³⁴ EC Draft Guidelines (2013), page 57, paragraph 218.

³⁵ EC Draft Guidelines (2013), page 56, paragraph 219 (e).

3. CRM Justification and Design

This chapter outlines the arguments on which we rely subsequently when we examine the RAs' seven "options" for a reformed CRM and set out the minimum requirements for evaluating them. In particular:

- Section 3.1 outlines the arguments for keeping a CRM in the all-island generation market. The full detail supporting these arguments can be found in Appendix A; and
- Section 3.2 considers certain questions put to us by Viridian about the design of a CRM. We support these arguments in detail in Appendix B.

The CRM currently operating within the all-island market is an attempt to overcome the market failures that prevent an energy-only market from delivering an efficient mix of generation. These market failures are still relevant to the choice of CRM. When considering the design of a reformed CRM (or any alternative market arrangement), the RAs should consider the coverage of the scheme, the need to provide efficient signals for market entry and exit, avenues for abuse of dominance, and its compatibility with the EU Target Model.

3.1. The Need for a CRM in the SEM

Energy-only markets are in principle capable of delivering a generation mix that is both allocatively efficient (demand is met at least cost every half hour) and dynamically efficient (sufficient investment takes place to ensure future demand is met optimally). Because generator capacity is limited, prices in an energy-only market will occasionally rise to the "Value of Lost Load" (VOLL) in times of scarcity. At those times, demand is met by an efficient mix of generation and load-shedding. Such "price spikes" are needed to offer peaking plants and other generators the opportunity to recover their fixed costs. (See Appendix A, Section A.1.)

In practice, market failures mean that energy-only markets may not encourage efficient investment in generator capacity. Significant political and regulatory risk diminishes the value to investors of markets that rely on prices rising to VOLL. Regulatory and political institutions tend to react adversely to price spikes, and many energy market rules explicitly cap wholesale prices below the level of VOLL. Even if such *explicit* caps are absent, as long as regulators remain averse to price spikes, market participants will face a risk that regulators intervene to prevent high prices from occurring. This *threat* of regulatory intervention places an *implicit* cap on prices. Any cap on prices (whether explicit or implicit) creates a problem of "missing money" – a shortfall in the revenue required to cover the cost of investing in generator capacity. (See Appendix A, Section A.2.1.)

Limited participation by consumers (the demand-side) in energy markets is likely to compound this problem. The limited scope for consumers to participate in energy markets means that the demand curve for electricity is very "inelastic", i.e. demand does not respond to price movements. Inelastic demand makes electricity prices more volatile, heightening the regulatory and political risks surrounding the reliance on high prices, diminishing expected revenues and deterring investment. An inelastic demand curve also facilitates the exercise of market power, which invites more regulatory interventions. (See Appendix A, Section A.2.2.) Limited participation in the associated market for long-term contracts means that the forward curve of prices does not give investors reliable signals about the future need for capacity. (See Appendix A, Section A.2.3.)

The problems above are prevalent in a small market, especially one characterised by large investment in long-lived assets. In a small market, problems in co-ordinating “lumpy” investment mean that investors require long periods of capacity shortage and high prices before they will build new capacity, in case their investment produces a long period of excess supply and low prices. (See Appendix A, Section A.2.4.)

A review of the SEM suggests that these problems are still likely to afflict the all-island energy market. In particular, the presence of an explicit cap on wholesale prices (as well as the recent history of regulatory intervention) is likely to create a “missing money” problem. In addition, the presence of a potentially dominant (and state-owned) player in the wholesale market may increase the perception by market participants that prices are effectively capped. (See Appendix A, Section A.3.)

A CRM is an attempt to overcome the failure of the energy-only market to prompt adequate investment in capacity, by replacing revenues from occasional energy price spikes with a smoothed payment for capacity.

In 2007 the RAs recognised that conditions in the SEM justified such a mechanism – a position that they reaffirmed as recently as 2012 in their Medium Term Review. There seems to be no reason to believe that conditions in the SEM have changed sufficiently to remove the need for a CRM. Even if the SEM could manage without a CRM in the short term, it would be opportunistic (and therefore harmful to investment) to remove the CRM now, with the intention of re-introducing it later, if it became necessary. (See Appendix A, Section A.4.)

3.2. High Level Design Questions

On the assumption that some sort of CRM is required in the SEM, Viridian asked us to address some high level design questions about its design.

3.2.1. Coverage of the scheme

The EC and the RAs both view “targeted” CRMs favourably, suggesting that they “distort” the market less than “market-wide” CRMs. However, this view betrays a misunderstanding of the economics of electricity systems. Targeted schemes may help with the system operator’s need for the flexible generation required to provide short term operating reserves. However, targeted “strategic reserves” do little to aid generator adequacy, i.e. the provision of enough capacity to meet peak demand. They merely distort the selection of generator capacity by displacing or “crowding out” cheaper forms of generation capacity.

Inclusion of “targeted” options in the RAs’ list highlights the need to understand the purpose of a CRM by identifying a problem with the electricity market, and to check that the proposed CRM will remedy the identified problem. Following such a process will help to meet the EC’s criteria for State Aid. (See Appendix B, Section B.1.)

3.2.2. Provision of efficient exit signals

A well designed CRM will induce efficient exit from the market, as well as efficient entry into it. When the legacy of historical investment decisions means that there is excess capacity in the market, it is efficient for plant with high costs to retire. The plant with the highest costs may not be the oldest plants. The selection of plant to retire is likely to be

relevant in the SEM, which has a 30 per cent generation margin at present. (See Appendix B, Section B.2.)

3.2.3. Abuse of dominance (market power)

The design of the SEM includes a number of safeguards against the abuse of market power – both withholding supply to increase prices and predatory (or merely non-commercial) reductions in prices to increase market share. These safeguards arose from a recognition that some generator companies have large market shares and/or are state-owned and therefore subject to non-commercial pressures. The rules of the SEM energy market – in particular the Bidding Code of Practice – were designed to give investors more confidence that market outcomes would reflect the interplay of supply and demand in competitive conditions.

Similar considerations will arise in the design of any CRM. In particular, other capacity markets have broken down the distinction between “price-based” and “quantity-based” schemes, by introducing a trade-off between price and quantity – otherwise known as a demand curve. Careful consideration of market power and measures to mitigate its effects should form part of the design process for the future CRM or any alternative market arrangement. (See Appendix B, Section B.3.)

3.2.4. Compatibility with EU Target Model

Finally, the EU Target Model neither permits (nor forbids) the introduction of a CRM, but the design of any CRM must be compatible with it. The current CRM in the SEM is unlikely to meet that standard, because the *ex post* component militates against risk management in day-ahead cross-border trading. The risk it creates acts as a barrier to hedging and to efficient trade across borders.

In practice, the desire to promote cross-border trading may not require a fundamental redesign of the existing CRM. It may be enough to replace the current *ex post* element with a payment fixed *ex ante* (e.g., by adjusting the shares of each component). The RAs might also follow the example of the UK government in excluding foreign generators and traders from participation in the CRM, so that trade between the SEM and the British market is driven by the difference between energy prices alone. (See Appendix B, Section B.4.)

3.3. Conclusion

The arguments that we have outlined above (supported in Appendix A of this report) suggest that there is no reason to think that the market failures recognised by the RAs in 2007 and 2012 are no longer present in 2014. To the extent that these market failures are well understood, have already received the concerted attention of the RAs and are not soluble by alternative means, a CRM remains a necessary feature of the reformed SEM.

The answers to the high level questions on CRM design that we have outlined above (and detailed in Appendix B) suggest that careful consideration is needed to ensure the chosen CRM is fit for purpose within the all-island market. In particular, we note that the coverage of the CRM needs to be justified with reference to the market failure it is aiming to address. Any evaluation must also consider the need to induce efficient exit, to mitigate market power, and to remove barriers to cross-border energy trading and risk management.

4. Evaluation of Options

4.1. The RAs' Seven Options

As discussed in Chapter 2, the RAs have identified seven “options” for a reformed CRM. These options are set out in the SEM Consultation paper (and repeated in Figure 2.4 above) under the following titles:

- 1: “Strategic Reserve”
- 2a: “Long Term Price Based”
- 2b: “Short Term Price Based”
- 3: “Capacity Auctions”
- 4: “Capacity Obligations”
- 5a: “Centralised Reliability Options”
- 5b: “Decentralised Reliability Options”

These seven options are likely to provide the basis for future consideration of CRM designs. However, the framework used to define these options does not appear to have been applied comprehensively. Some items mentioned in Table 9 of the SEM Consultation (such as the “Timings and distribution of the CRM”) are missing from taxonomy in figure 16 on the next page. Some lists included in both Table 9 and Figure 16 are not exhaustive or mutually exclusive (such as the list of items under “Level of Intervention”). In paragraphs 10.7.1 to 10.15.5, the SEM Consultation provides only high level descriptions that do not specify each option in full.

The options have not therefore been developed to be point where anyone can conduct a comprehensive evaluation of the system best suited to the all-island SEM. Indeed, the SEM Consultation assesses each option by a different set of criteria, which prevents a proper comparison of their relative merits.

A proper evaluation of CRM options would require a full specification of each design. However, we understand that the RAs have given themselves limited time to design, evaluate and select the appropriate option. This process may require some options to be evaluated in more detail than others, but it would be undesirable to overlook potential major advantages or disadvantages. Below, therefore, we set out our recommendations for the next stage in the process as guidance on the evaluation of individual options.

4.2. Relevant Factors

For each of the seven options, we begin by setting out our understanding of the relevant CRM and of any areas that still require clarification. We then note important factors that the RAs would have to take into account when developing and evaluating each option. The list of the factors relevant to these options derives from the analysis presented in Appendix A and Appendix B. In those appendices, we identify the following concerns.

4.2.1. The problem to be addressed by the CRM

The first concern to be considered in any evaluation of options is ensuring that a CRM is fit-for-purpose. In Appendix A, section A.2, we discuss a number of reasons for electricity markets to include a CRM, which we summarise here:

- Instability of prices, due to the small size of the all-island electricity market relative to minimum-scale investments in generation capacity;
- Lack of liquidity in forward contract markets, limiting the ability of generators to manage risks;
- The corresponding threat to generator adequacy due to the “missing money” problem caused by:
 - Explicit caps on the energy price imposed by the SEM rules and the Bidding Code of Practice;
 - Implicit caps on the energy price imposed by the threat of (1) regulatory and political intervention in markets and of (2) policies that deny generators the opportunity to recover costs;
 - Inadequate provision of pricing signals due to transactions costs, e.g. lack of demand side participation, and insufficient disaggregation (“granularity”) of energy prices by time and location.
- Selection of particular types of generation to meet specific purposes (by location or for flexibility), due to the lack of granularity in market price signals.

Appendix A, Section A.3, provides more detail on the market failures that are likely to affect the SEM, which provide the justification for a CRM. We illustrate there how a CRM provides an alternative to relying on revenue from the energy market when prices spike to VOLL. A CRM should provide generators with a replacement source of revenue, which is needed to cover their fixed costs. Renewable generators may also rely on this payment, to the extent that the direct subsidy they receive under various environmental policies is insufficient to cover their costs without an additional payment for capacity.

Understanding and identifying the reason(s) for introducing any CRM will be an important part of any evaluation process, and it will help deal with the EC’s guidelines on State Aid. Indeed, providing a good reason for including a CRM within the SEM would fulfil a large part of the EC’s own requirements for State Aid. Questioning the purpose of each option will therefore be important, to ensure that the design of the new I-SEM, and of its CRM in particular, is tailored to conditions within the island of Ireland, and is not merely selected to circumvent administrative barriers.

4.2.2. Minimising regulatory/political risk

The problems listed in the previous section derive, to a large extent, from regulatory and political risk. A CRM will not solve these problems unless it minimises regulatory and political risks, either by reducing it or by offsetting it:

- A CRM *reduces* regulatory and political risks if it removes the source of the risk (such as reliance on occasional high electricity prices) and replaces it with a less risky alternative (such as – for example – a capacity payment spread over many periods).

- A CRM *offsets* regulatory and political risks if it merely provides additional revenue for long term investments in capacity, whilst leaving the existing risks unchanged.

In assessing whether a proposed CRM minimises regulatory/political risk, it is necessary to consider the following aspects of its design:

- The potential for over-remuneration of capacity, in the short term or over the long term, within the design of a CRM; and
- The risk inherent in the mechanism (whether automatic “demand curves” or discretionary changes to parameters) used to adjust a CRM in the light of over- or under-provision of capacity.

These factors may require a trade-off between the provision of accurate short-term price signals and the desire to avoid extreme prices. Assessing the benefit of different trade-offs requires detailed knowledge of the design of any CRM. If such details are not available, any option to be evaluated must at least include draft rules that show how it will address the regulatory/political risk used to justify its adoption.

4.2.3. Mitigation of market power in the supply of capacity

The energy component of the all-island SEM is constrained by rules intended to mitigate the impact of market power. Concerns over market power arise both from the incentive for private sector generators to raise or lower prices if that would increase their profits, and from the ability and tendency of state-owned generators to lower prices for political reasons. The same concerns should inform the design and evaluation of any CRM.

The EC guidelines on State Aid and a number of statements by the RAs put great emphasis on the desirability of using markets to set the price of capacity. In practice, capacity markets will not produce efficient prices or desirable outcomes if they allow individual providers of generating capacity and demand-side resources to move prices significantly by expanding or contracting their supply. As noted above, the price-elasticity of the demand for capacity has a major influence over the degree of market power possessed by individual sellers (and buyers). In some conditions, “inelastic” demand for capacity (e.g. a fixed obligation) gives many suppliers a major influence over the price of capacity. A CRM may produce a better outcome if it dampens the change in prices caused by any variation in supply (e.g. by including a demand curve). As with regulatory/political risk, achieving this aim may require some trade-off, this time between providing accurate short-term price signals and preventing the manipulation of prices.

4.2.4. Cross-border trade

The motivation for the current review is the desire to promote more efficient trade in electricity across borders between member states. The EU has developed a target model as a way to promote trade by harmonising institutions. In practice, though, the target model provides for a wide range of discretion over whether to adopt a CRM, and how it would look.

The target model focuses on the closer integration of cross-border day-ahead trading (with the integration of within-day trading following in future, perhaps). For the all-island SEM, its crucial border is with the British electricity market. The success of this integration therefore

depends on the extent to which the form and timing of day-ahead energy prices and capacity incentives (of whatever form) match on both sides of the border.

The Electricity Market Reform (EMR) in Britain is still being developed, which makes it difficult to coordinate the design of the I-SEM with it. At this point, the EMR proposals include provision for market-wide capacity contracts procured centrally four years in advance. These contracts will be backed up by a substantial penalty for not providing energy from contracted capacity when requested by the system operator. The penalty represents the real-time incentive to provide capacity, although cross-border trading may only be feasible up to the day-ahead stage. Only capacity located in Britain will be able to acquire a capacity contract. Interconnectors will not be eligible to participate in the capacity market.³⁶

Given the uncertainty surrounding the final design of the EMR, it would be difficult, and potentially unwise, to choose a mechanism solely for the sake of harmonising cross-border trade with Britain. Details of the British system may change before and after implementation of the EMR and the I-SEM. When evaluating options for a CRM in the all-island market, therefore, it will be necessary to consider how any proposed CRM would fit different schemes – in particular, how it can be adapted to fit (1) day-ahead trading and within-day trading; (2) a British market that does not pay for capacity provided by interconnectors; and (3) different levels of penalty for not providing capacity in Britain.

4.2.5. Summary

From the discussion above, we conclude that any evaluation of different CRM options must, at the very least, address the following questions:

- What is the purpose of the proposed CRM, in terms of the market failure it is intended to remedy – instability, illiquidity, “missing money”, or transactions costs?
- How exactly will the proposed CRM remedy that market failure?
- Will the CRM reduce (or offset) existing regulatory/political risks? What new regulatory/political risks does it introduce?
- How will the proposed CRM mitigate the impact of market power (both withholding supply to raise prices and expanding or maintaining supply to lower prices)?
- How will the proposed CRM manage cross-border trading with the currently proposed EMR and how can it be adapted to accommodate specific changes in: (1) day-ahead *versus* within-day trades over the interconnector; (2) different eligibility rules for interconnector capacity in Britain; and (3) different levels of penalty for non-performance in Britain’s capacity market?

With the detail available at this stage, it is not possible to answer all of these questions for every option identified in the SEM Consultation. In the next section, therefore, we comment on the RAs’ options, as defined so far, using these questions to identify the minimum requirements for any subsequent evaluation.

³⁶ DECC (October 2013), *EMR: Consultation on Proposals for Implementation, Chapter 4 (EMR: Capacity Market – Detailed Design Proposals)*, page 153.

5. Minimum Requirements for Evaluation of Options

The RAs may take forward a subset of the options identified in the SEM Consultation. We therefore offer the following comments on each option as far as possible on a standalone basis. This approach entails some repetition of key points and cross-references to other options, but that is unavoidable.

5.1. Strategic Reserve (Option 1)

This is the only option that is “targeted” (limited to specific sources of capacity) rather than “market-wide” (applicable to all eligible capacity). Adoption of this option therefore requires particularly careful consideration of the reasons for having a CRM in the all-island electricity market.

The decision to include a CRM in the original design of the SEM sprang from concerns over future security of supply (generator adequacy) due to: the small size of the market; the potential for the market to oscillate between surpluses and shortages; and the regulatory/political risk attached to a reliance on extreme electricity prices to attract investment. The design adopted in 2007 also acknowledged the “missing money” due to the Bidding Code of Practice and an explicit price cap (by adopting a solution which made up for the “missing money” whilst carefully avoiding over-remuneration). In turn, those restrictions on bidding reflected concern about the market power of dominant players within the electricity sector. Any decision to proceed with a “strategic reserve” targeted on a limited number of generators would have to explain why all these concerns were no longer relevant.

5.1.1. Effect on regulatory/political risk

Although other electricity markets have sometimes adopted a strategic reserve, the grounds for maintaining one remain obscure. As we explain in greater detail in Appendix B, Section B.1, a strategic reserve does not contribute towards generator adequacy, contrary to the suggestion in the SEM Consultation.³⁷ Instead (as the SEM Consultation goes on to recognise), strategic reserve enables generators of one favoured type to displace other (usually cheaper) generators of a different type. The favoured generators are then held off the market until all other sources have been exhausted.³⁸

Conditions within the SEM have prompted discussion of a supposed need for more flexible generation, to deal with the growing volume of output from intermittent renewable sources. However, flexible generation would not be held off the market and used only as a last resort. Instead, it would be used whenever other generators were available but unable to respond quickly enough to offset the change in output from renewable sources. At such times, there is no loss of load and it would be inefficient to price electricity at the Value of Lost Load.³⁹

³⁷ I-SEM – High Level Design (2014), page 109, paragraph 10.7.2.

³⁸ I-SEM – High Level Design (2014), page 109, paragraph 10.7.3.

³⁹ I-SEM – High Level Design (2014), page 109, paragraph 10.7.3.

The system operator typically has a legal obligation to ensure *short term* security of electricity supply. To meet the need for flexible generation, the system operator might have to increase the volume of its contracts for short term operative reserve (the ability to follow load, minute by minute, a conventional system service). However, increasing short term operating reserve does not improve long term generator adequacy (the ability to meet peak load, when it occurs). Indeed, there is no analogous obligation placed on the system operator to ensure security of supply in the *long term* (which is the purpose of a CRM). Discussion of the system operator's need for short term operating reserve should not therefore distract from consideration of long term generator adequacy.

If the RAs decide to proceed with a new electricity market that only contains a strategic reserve *and no other CRM*, it will be important to explain to market participants how the new market is intended to encourage investors to build and maintain capacity. As noted in Section 2.1.2, the current forecast of a capacity surplus lasting for several years depends implicitly on maintaining the current level of incentives. If the RAs plan to remove the current CRM and not to replace it with any market-wide alternative, it will be essential to review the forecast of capacity and to check that the new market will achieve long term security of supply, in the form of generator adequacy.

The answer to this last question – how the new market will achieve long term security of supply - must set out a convincing and stable vision of the SEM's future. The SEM Consultation suggests that the new market would rely on high electricity prices at times of shortage.⁴⁰ However, it is not obvious that this approach is any more credible in 2014 than it was in 2007 or 2012. It is no solution to this problem to propose removing the CRM now, during a period of capacity surplus, and retaining the option of re-introducing a CRM when capacity shortages are imminent. A CRM is a *de facto* price cap imposed in lieu of high electricity prices; it only provides incentives to invest if it is maintained over the cycle of capacity shortage and surplus. Any proposal to remove it now and to introduce it later would be an opportunistic regulatory policy that prevents cost recovery, raises regulatory risk and discourages investment in the long run. Any evaluation of this option would have to find some way to dispel this impression that it is part of an opportunistic regulatory policy.

Overall, therefore, we find it hard to envisage any conditions in which the creation of a “strategic reserve” is the optimal response, or even an effective solution to a problem. We appreciate that the system operator may anticipate a rising demand for flexible generation, but that demand concerns the level of short term operating reserve, not long term generator adequacy. Any decision to proceed with a strategic reserve and no other CRM would have to be backed up by a rigorous explanation. In particular, the RAs would have to explain to investors why none of the reasons for introducing a market-wide CRM in 2007 were now relevant, to avoid creating a perception of opportunism and increasing regulatory risk.

5.2. “Long Term Price Based” (Option 2a)

The SEM Consultation distinguishes between “price-based” and “quantity-based” CRMs, which is a false dichotomy in practice, or at least a mis-labelling of the key decision. Box 1

⁴⁰ I-SEM – High Level Design (2014), page 110, paragraph 10.7.6.

below examines this distinction and concludes that it refers to the difference between a “spot price” for capacity and “forward contracts” for capacity.

Box 1: Price-Based and Quantity-Based CRMs

The SEM Consultation distinguishes between “price-based” and “quantity-based” CRMs, which is a false dichotomy in practice, or at least a mis-labelling of the key decision. In practice, no CRM sets out a fixed price or a fixed quantity in perpetuity, because setting the price or quantity at the wrong level can result in (respectively) the wrong quantity or an unacceptable price of capacity emerging in the market.

Some CRMs have automatic adjustment mechanisms in the form of a demand curve, which specifies a trade-off between price and quantity. CRMs that have no demand curve require the relevant authority to make discretionary changes to key parameters (and CRMs that include a demand curve are not immune from such tinkering with the rules).

In practice, the SEM Consultation distinguishes between:

- (1) CRMs that offer a kind of real time market for capacity that pays a “spot price” at the time when capacity is provided; and
- (2) CRMs that set up a commitment or “forward contract” for capacity offered in advance, backed up by a spot or real time penalty for non-delivery.

5.2.1. Effect on regulatory/political risk

Option 2a seems to fall into the first category, a “spot price” for capacity, since it offers a payment for capacity at the time when it is provided. However, the SEM Consultation explains that the total annual pot of revenue available for capacity payments would be calculated (and split into monthly pots) in advance.⁴¹ As with the current CRM, owners of available capacity would then divide this monthly pot between them. This scheme incorporates a demand curve to the extent that a surplus of capacity will depress the spot price – the amount paid out to each unit of capacity – and vice versa. We consider the demand curve implicit in this proposal, and in the current CRM, in more detail in Appendix B, Section B.2.2.

The SEM Consultation regards this type of CRM as a spot price (i.e., “price-based”) system, because it assumes that there is no obligation or penalty for under-performance, except the loss of revenue at the current capacity price. However, the Consultation discusses the effects of deviations between forecast and actual capacity (and demand).⁴² Such deviations seem to imply a pre-commitment. In any case, even a system which pays for actual capacity (“*ex post*”) might impose penalties on generators who repeatedly declare capacity available (and collect capacity payments), but who then provide no output when requested.

⁴¹ I-SEM – High Level Design (2014), page 111, paragraph 10.9.2.

⁴² I-SEM – High Level Design (2014), page 111, paragraph 10.9.5.

5.2.2. Effect on cross-border trade

The SEM Consultation also suggests that interconnector users would benefit from offering capacity (when delivering power into the SEM) or pay for using capacity (when exporting power to Britain) “if the *ex ante* capacity price is added to bids into the [Day-Ahead Market]”.⁴³ However, it is not clear that including the payment per MWh of available capacity in the price per MWh of electricity is efficient. Under the current proposals for EMR in Britain, electricity exported from Ireland to Britain would not earn a capacity payment of any kind. The evaluation would have to examine the potential distortions caused by this approach.

In any case, unless this CRM is viewed as a development of the existing scheme which requires no further approvals at European level, it will need a convincing explanation of the reason for including it in the SEM. It appears to be aimed at strengthening incentives to invest by compensating for “missing money”. To show that it can achieve this aim, the supporting documentation would have to demonstrate that it provides a stable mechanism – ideally a more stable mechanism than relying high energy prices to encourage investment.

5.3. “Short Term Price Based” (Option 2b)

Option 2b also falls under the heading of spot price, using the distinctions made in Box 1. Indeed, this option moves the determination of capacity payments closer to real time, by using a formula related to current estimates of scarcity (a “regulated scarcity rent function”).⁴⁴

Whereas option 2a dispenses with the *ex post* element of the existing CRM, option 2b relies on it entirely. The SEM Consultation describes a final calculation undertaken *ex post* based on actual availability and demand.⁴⁵ If the result is intended to mimic the current *ex post* calculation, it provides an odd basis for rewarding capacity. *Ex post*, the value of capacity is either zero (if supply exceeded demand) or the difference between the energy price and VOLL (if demand exceeded supply). A loss of load probability is a prediction about the future; calculating it *ex post* with actual data produces a hybrid concept that has no economic meaning.

5.3.1. Effect on regulatory/political risk

Any evaluation of this option will have to consider the regulatory/political risk of relying on a potentially volatile *ex post* estimate of capacity payments. If the CRM is intended to reduce or offset regulatory/political risk, it will be necessary to show how an *ex post* capacity payment provides a more stable and reliable source of revenue than the alternative energy price. The SEM Consultation proposes that the capacity price would be “fully responsive to the capacity margin”.⁴⁶ However, whilst this approach strengthens incentives to provide

⁴³ I-SEM – High Level Design (2014), page 111, paragraph 10.9.4.

⁴⁴ I-SEM – High Level Design (2014), page 112, paragraph 10.10.2.

⁴⁵ I-SEM – High Level Design (2014), page 112, paragraph 10.10.2.

⁴⁶ I-SEM – High Level Design (2014), page 112, paragraph 10.10.2.

capacity when it is needed, it reduces investor certainty over future revenues, makes prices volatile in the short-term and enhances market participants' ability to raise capacity prices by withholding capacity (or to lower capacity prices by keeping more capacity available).⁴⁷

Thus, any evaluation of this CRM would have to assess the effects of more “responsive” capacity prices on regulatory/political risk, the exercise of market power, and investment in security of supply.

5.3.2. Effect on cross-border trade

As with option 2a, the SEM Consultation proposes to include this capacity price in bids into the day-ahead electricity market. This allows the SEM Consultation to claim that interconnector users will benefit from (or pay for) capacity appropriately. However, no economic rationale for this adjustment to SEM electricity prices is spelled out.⁴⁸ This aspect of the design will require detailed attention, before any evaluation is feasible.

5.4. “Capacity Auctions” (Option 3)

According to the distinctions made in Box 1, option 3 uses forward contracts auctioned off by a central authority and enforced by a real-time penalty for non-delivery which could be “as high as VOLL”.⁴⁹ The SEM Consultation suggests that this type of CRM is to be found in the proposed capacity mechanism for Britain, but that description overlooks the current proposals for penalties.⁵⁰ Whereas early versions of the EMR foresaw penalties based on energy prices (rising to VOLL during a capacity shortage), the latest proposals anticipate a penalty rate fixed somewhat lower than VOLL, in conjunction with a cap on any individual market participant's total annual penalties defined as a multiple of its annual capacity payments. The SEM Consultation omits these details, but recognises the reason for them, namely that some providers may be unable to bear the risk of high penalties, causing them not to take part in the auction.⁵¹ The penalty aspects of the design are crucial and will have to be spelled out before any meaningful evaluation can be carried out.

⁴⁷ **I-SEM – High Level Design** (2014), page 113, paragraphs 10.10.6 – 10.10.8.

⁴⁸ The Electricity Pool of England and Wales, which operated from 1990 to 2001, applied this kind of mark-up to day-ahead energy prices, using a formula which replicated forward market pricing based on a (truncated) view of future possible spot prices. The formula assumed that the future spot price would be either the System Marginal Price (SMP) calculated from generator bids, or the Value of Lost Load (VOLL). In the former case, generation would be sufficient to meet demand, but in the latter case load would be lost. The respective probabilities of each case were therefore (1-LOLP) and LOLP, where LOLP was the estimated “Loss of Load Probability”. The resulting formula was a probability-weighted average – $SMP \cdot (1-LOLP) + VOLL \cdot LOLP$ – which represents an estimate of a forward price. The formula was shown differently in the Pool Rules as SMP plus a mark-up equal to $LOLP \cdot (VOLL - SMP)$, leading some readers to misinterpret the mark-up as a capacity payment. It is possible that the description of option 2b is subject to the same misinterpretation.

⁴⁹ **I-SEM – High Level Design** (2014), page 115, paragraph 10.11.6.

⁵⁰ **I-SEM – High Level Design** (2014), page 114, paragraph 10.11.1.

⁵¹ **I-SEM – High Level Design** (2014), page 115, paragraph 10.11.6.

5.4.1. Effect on regulatory/political risk

As with all the options, the effect of option 3 on regulatory/political risk requires careful consideration. The SEM Consultation suggests that option 3 will provide “a relatively stable environment for capacity investment”, but its stability depends on the methods used to determine total capacity requirements and for defining eligible capacity.⁵² The stability and transparency of a contract auction can be undermined by discretionary changes to rules such as the definition of eligible capacity and the required quantity of capacity.

As in any mechanism, the eligibility rules must establish the amount of capacity that generators of each type can provide, and the penalties for not doing so. These rules need not place the same requirements (and impose the same penalties) on generators using different technologies. The SEM Consultation mentions (but does not describe) the effect of the penalty arrangements on regulatory risk.⁵³ Such effects would have to be examined in detail, if the purpose of the scheme is to reduce or offset regulatory risk.

5.4.2. Effect on market power in the supply of capacity

This option anticipates users taking on contractual obligations in advance, so they must be able to trade their obligations, to reflect changes in their sell-side offers (available capacity). Without such trading, energy companies would not be able to adjust their portfolio of generation capacity, which would restrict long term competition in the wholesale electricity market.

In 2007, there were severe doubts about the degree of competition and the level of liquidity in the wholesale electricity market. The SEM therefore forces transparent trading and restricts generators’ bidding, through compulsory participation in the day-ahead market and a Bidding Code of Practice. Given the importance of capacity trading to the success of option 3, and the potential influence of market power and illiquidity, a similar approach to trading would be required in the capacity market. Any evaluation of this option must therefore consider measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis. The SEM Consultation recognises the need for market power mitigation measures in the original contract auction, but overlooks the need for similar measures to facilitate secondary contract trading.⁵⁴

Many US mechanisms involve bidding rules that constrain participants’ behaviour in order to mitigate market power. Concerns about the market power of capacity purchasers have resulted in a number of proceedings before the Federal Energy Regulatory Commission (FERC). For example, in 2006 a publicly owned supplier in Connecticut procured additional capacity within the state. Under the terms of its contract, the capacity had to bid in to the New England capacity market at a marginal cost of zero. This practice attracted widespread

⁵² I-SEM – High Level Design (2014), page 115, paragraph 10.11.10.

⁵³ I-SEM – High Level Design (2014), page 115, paragraph 10.11.11

⁵⁴ I-SEM – High Level Design (2014), page 116, paragraph 10.11.14

suspicion, with complaints from other market participants that the state of Connecticut was interfering with the auction process in order to depress the capacity prices that consumers in the state would have to pay.⁵⁵ Regulators in the US have since implemented a number of mechanisms to combat gaming, with frequent revisions to the bidding rules. One clearly identifiable example is the existence of Minimum Offer Price Rules (MOPRs) which prevent buyers from offering to sell capacity (or demand side response) at a price below what the regulator deems to be the competitive level. The Connecticut case offers parallels to the situation in Ireland, where a large state-owned company, ESB, may have an incentive to depress the capacity price (or where other market participants may just be concerned that ESB has such incentives). We analyse the issue of market power in the SEM in more depth in Appendix A, Section A.3.4.

US markets also contain bidding rules which constrain the behaviour of bidders in capacity markets. The PJM, for instance, has rules which regulate the bids of all players with “market power”. The rules stipulate that any generators can bid at most the market administrator’s calculation of “net going forward costs” (i.e. the difference between its forecast revenues and costs) into the capacity market.⁵⁶ The market rules define any player whose capacity is pivotal with any two other players as having market power.⁵⁷ The result is that virtually all the incumbent generators have market power according to the PJM’s definition and the bids of all incumbent generators are strictly regulated.⁵⁸ Moreover, New England has an “insufficient competition rule” which abandons the auction in favour of a clearing-price rule whenever insufficient generation is present up to run the auction successfully.⁵⁹ As a result, although capacity markets in the US are competitive auctions in *form*, in practice they are often administered payments in *outcome*.

5.4.3. Effect on cross-border trade

With regard to cross-border trading, the SEM Consultation seems to anticipate the same difficulties that led the designers of the EMR to leave out interconnectors from the capacity market. That would leave cross-border trade being driven by the difference in energy prices. Any evaluation would have to take into account the effect of explicit or implicit price caps within each market.

5.5. “Capacity Obligations” (Option 4)

This option is a variant of option 3, in which the buy-side obligation is decentralised and allocated among all the energy suppliers in the market. According to the distinctions made in

⁵⁵ For more discussion of this case and the concerns about over-procurement, see: Miller, R. Butterklee, N., and Comes, M. (2012), “Buyer-Side” Mitigation In Organized Capacity Markets: Time For A Change?”, *Energy Law Journal*, **33**, pages 449-473.

⁵⁶ In addition, generators who disagree with PJM’s calculation of net going forward costs can submit their own calculation for approval. See *PJM Manual 18: PJM Capacity Market*, 30 January 2014, Section 5.3.4, page 83, referring to *Open Access Transmission Tariff - Attachment DD*, pages 68-69, Section 6.4, “Market Seller Offer Caps”.

⁵⁷ *Open Access Transmission Tariff*, Attachment DD, PJM, page 68, Section 6.3 (b), “Market Structure Test”.

⁵⁸ *State of the Market Report for PJM – Volume 2: Detailed Analysis*, Monitoring Analytics LLC, 2012, page 129.

⁵⁹ *ISO-NE Market Rules*, Rule number: III.13.2.8.2., “Insufficient Competition”.

Box 1, therefore, option 4 uses forward contracts in the form of an obligation imposed on individual suppliers and enforced by a real-time penalty for non-delivery. The individual suppliers can delegate the obligation by signing contracts with generators. That approach raises all of the same questions about the size and nature of the penalty as arose under option 3 (Section 5.4 above), plus a greater reliance on secondary capacity markets.

5.5.1. Effect on regulatory/political risk

Option 4 raises many questions about the stability and transparency of the regulatory decisions on the capacity obligations. The SEM Consultation says that option 4 reduces the level of regulatory intervention, compared with option 3, because it decentralises procurement.⁶⁰ This statement seems to be incorrect. Under option 3, the procurement exercise might involve regulatory discretion in the selection of winners, but one would hope the selection rules could be applied in a transparent and mechanistic manner. Decentralising the procurement exercise puts selection decisions in the hands of energy companies, but the regulatory still has to define or oversee the calculation of a total capacity requirement (as in option 3) and must in addition determine how this total capacity requirement will be allocated among energy suppliers. That difference does not appear to reduce regulatory intervention. Indeed, unless the RAs spell out the rules for defining the total capacity requirement and allocating capacity obligations among suppliers, it will be impossible for any evaluation to assess whether or not this option contributes to reducing the regulatory/political risk facing investors.

5.5.2. Effect on market power in the supply of capacity

Option 4 also relies on capacity trading, to a greater extent than option 3. It anticipates that suppliers will take on capacity obligations in advance, and procure capacity from generators to meet these obligations. Generators and suppliers must be able to trade the resulting obligations, to reflect changes in both their sell-side offers (available capacity) and their buy-side obligations (the demand of their consumer base). Without such trading, energy companies would not be able to adjust their generation portfolio or to supply customers beyond the level of their available capacity. Obstacles to capacity trading would therefore severely restrict competition in both wholesale and retail electricity markets.

As noted above, concerns over the degree of competition in wholesale markets in 2007 led to restrictions on generators' bidding in the SEM, through compulsory participation in the day-ahead market and a Bidding Code of Practice. Given the importance of capacity trading in this option, and the potential influence of market power, a similar approach is required in a capacity market. Any evaluation of this option must consider measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis. The SEM Consultation overlooks this need.

⁶⁰ I-SEM – High Level Design (2014), page 117, paragraph 10.12.4.

5.6. “Reliability Options” (5a: “Centralised”; 5b: “Decentralised”)

The SEM Consultation provides only short descriptions of “reliability options” – a term that arose during the earlier stages of the EMR process in Britain. What is remarkable about these descriptions is how little they differ from options already described above.

In terms of Box 1, a reliability option is a “quantity-based” capacity obligation which takes the form of a forward contract for capacity, with a spot penalty for non-delivery of energy when requested. The obligation to procure these forward contracts can be centralised (option 5a) or decentralised to suppliers (option 5b), just like any other capacity obligation (options 3 and 4). The penalty for non-delivery is defined as a “reference price” of energy, such as the day-ahead price.⁶¹ This rule is similar to the penalty under options 3 and 4, which might be “as high as VOLL”, except that the penalty under a reliability option is taken from energy markets instead of being set administratively at a level reflecting the value of energy or capacity.⁶²

5.6.1. Effect on regulatory/political risk

Judging by the description in the SEM Consultation, reliability options really are just a forward contract settled like a contract for difference at the current spot or reference price of energy. If sold by auction, they may not offer any additional value over expected energy prices.⁶³ Offering such contracts three or four years ahead is unlikely to improve investment incentives, as they would not constitute a long-term “bankable” commitment. They offer no additional revenue to offset “missing money” and energy prices will continue to rise and fall unabated, so there is no obvious diminution of regulatory/political risk. Any evaluation will therefore require a detailed explanation of the problem that reliability options are intended to solve and how they address it.

5.6.2. Effect on market power in the supply of capacity

The imposition of long-term obligations creates a need for capacity trading to reflect changes in available capacity and (in a decentralised scheme) retail market shares. Trading is subject to the same problems of market power and illiquidity as the energy market. These problems have been discussed above, in the context of other capacity obligations. It will only be possible to evaluate options 5a or 5b, once the RAs have spelled out measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis.

5.6.3. Effect on cross-border trade

Finally, reliability options seem to present no problem for cross-border trading, in large part because they have limited impact on any market. However, as noted above, the capacity

⁶¹ I-SEM – High Level Design (2014), page 117, paragraph 10.13.3.

⁶² I-SEM – High Level Design (2014), page 115, paragraph 10.11.6.

⁶³ Even if the total capacity requirement is very high and can only be met *physically* by building new capacity, it would be cheaper in most conditions to fulfil the contract *financially* at energy market prices. The expected level of those prices will effectively define the price at which sellers are willing to sell reliability options.

market proposed for Britain under the EMR has moved away from the original concept of a reliability option, whilst the SEM Consultation seems to have retained it. Any evaluation of reliability options will therefore have to take into account the effect on cross-border trade of the differences between the capacity market concepts on either side of the Irish Sea.

5.7. Conclusion

In this chapter, we have described the various options being considered for a CRM in the SEM Consultation and have identified major gaps in the proposed designs. Unless these gaps are filled in, it will not be possible to conduct any meaningful evaluation of the options set out so far.

Allowing for the uncertain design of each option and potential remedies, we have identified certain important questions that any evaluation of options would have to address. Different questions take different priorities with different options. We have therefore identified the most important questions in each case. Unless the RAs have spelled out the design of each option being considered, and answered the questions relevant to each option, no meaningful evaluation is possible.

The list of design tasks and questions identified above is by no means complete, but it represents the minimum requirement for any evaluation. Selection of a CRM will have a major impact on incentives for investment within the SEM. Investment will in turn have a major and long term impact on the cost of generation to consumers. It would therefore be contrary to consumers' interests to rush the selection of a CRM by ignoring important factors for the sake of administrative convenience.

The current CRM was intended to serve the purposes of the all-island electricity market, by strengthening investment incentives and reducing regulatory/political risk. It appears to have done so. Any future CRM should be designed and selected with the same intention of serving the purposes of the all-island electricity market.

From these observations, we conclude that the SEM Consultation has not specified the options for any future CRM in sufficient detail to allow a full evaluation of them. We conclude also that any future evaluation would have to take into account a number of important factors specific to the all-island electricity market, to ensure that it serves not just administrative requirements, but also the interests of consumers.

Appendix A. The Need for A CRM in Ireland

As described in Chapter 2, EC State Aid guidelines stipulate that a CRM can only be justified when demonstrable market failures give rise to a generation adequacy problem. This chapter evaluates whether conditions in Ireland meet these criteria such that there remains a need for the SEM to include a CRM. The chapter proceeds as follows:

- Appendix A.1 explains that, in order to deliver efficient market outcomes, energy-only markets rely on potentially volatile peak prices;
- Appendix A.2 outlines the market failures that can afflict an energy-only market; and
- Appendix A.3 examines whether these market failures in the SEM give rise to a continuing need for a CRM to ensure generation adequacy in the Irish context.

A.1. Energy-Only Markets Rely on Volatile Peak Prices to Deliver Efficient Outcomes

In principle an energy-only electricity market can deliver a generation mix that is *allocatively* efficient and investment in capacity that is *dynamically* efficient. For this result to hold the market must be (1) “complete” – meaning that every good associated with electricity can be traded – and (2) competitive – meaning that there are enough market participants (and little enough government intervention) so that no one has the power to set prices unilaterally.⁶⁴

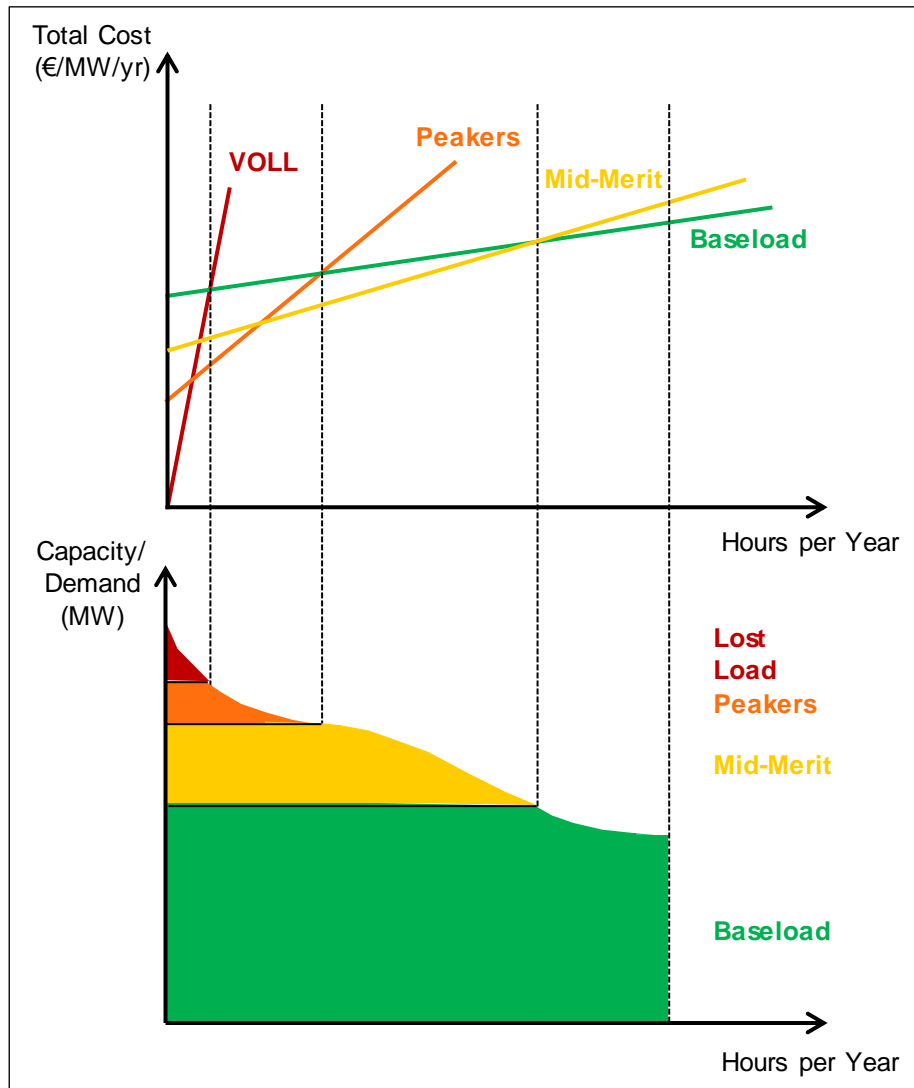
Allocative efficiency occurs, when resources are directed towards their most productive use, and realise the greatest benefits for society, in the short-term. In a competitive energy market, load is served by the mixture of generation technologies and fuels which minimises total cost (both fixed and variable). This outcome is illustrated in Figure A.1, where we show the load duration “screening curve”. Each upward-sloping line represents the total cost of meeting electricity demand from one generation technology and fuel, for different numbers of hours per year. Baseload plant is represented by the green line. It has high fixed costs, but low variable costs, so it starts high at zero hours of generation (on the left hand side) but rises only slowly as its hours of generation increase (from left to right). Peaking plants are represented by the orange line. They have lower fixed costs but higher variable costs. Their total costs start low at zero hours of generation, but rise rapidly as their hours of generation increase. The costs of mid-merit plant, in yellow, sit between those of baseload and peaking plant in every respect. The green line, representing the total cost of running baseload plant, lies above the lines for other generator technologies/fuels initially (at low levels of output). However, the low variable costs of baseload plant make it the cheapest solution for extended operating hours. Mid-merit and peaking plant offer the lowest cost solutions for running different numbers of hours per year.

For demand that only lasts very few hours per year, the least cost way to meet it is by shedding load. Shedding load is valued at the social Value Of Lost Load (VOLL), i.e., the maximum price a customer would be willing to pay to receive one more unit of electricity. Every electricity market should expect to shed a few hours of load per year *on average*, as

⁶⁴ The result is known as the First Fundamental Theorem of welfare economics.

represented by the red area of the load duration curve in Figure A.1. Occasional price spikes, when the real-time value of electricity rises to VOLL, are therefore a feature of any energy-only market that is meeting demand with the efficient mix of generation and load shedding.

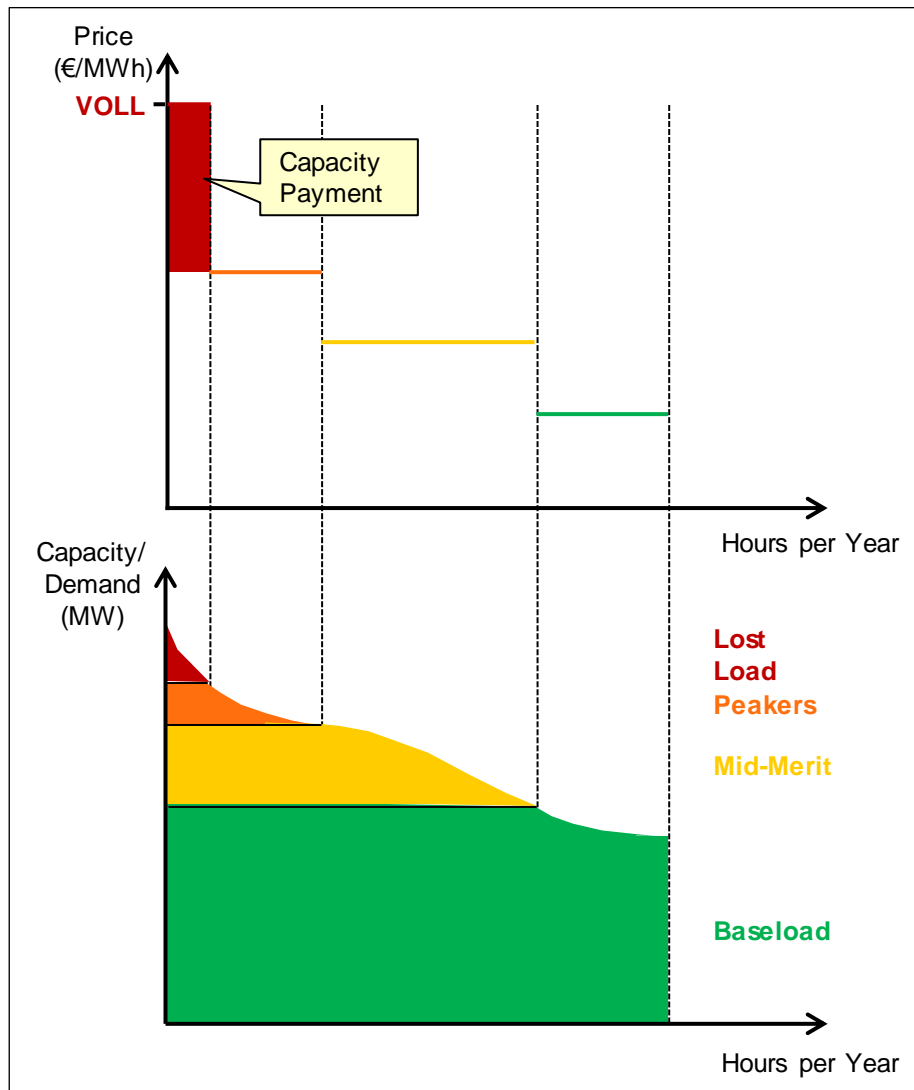
Figure A.1
Energy-Only Markets Incentivise Electricity Dispatch At Least Cost



Indeed, such real-time price spikes (or the equivalent rise in expected prices, in trading before delivery takes place) are *necessary* to cover the fixed costs of peaking units (and other plants). Figure A.2 shows that, for most half hours a year, prices in an energy-only market reflect the cost of production from the marginal source of supply. At peak times, prices rise above the marginal cost of a peaking plant to reflect the scarcity of generating capacity (and the value to customers of a reliable electricity supply). Since, typically, technological constraints or high transactions costs prevent customers from bidding into the wholesale electricity market, VOLL is a maximum price set administratively (usually by governments or regulators) as a proxy for what they would bid. In hours of load shedding, the electricity price rises to the level of this “quasi-bid” and the “scarcity rent” within this high price remunerates the fixed capacity costs of peaking plant. More remarkably, as long as the generation mix is efficient

and the market is competitive, these scarcity rents also remunerate the share of the higher fixed costs of mid-merit and baseload plants that they cannot recover from profits on their sales of energy.⁶⁵ In this sense, energy-only markets provide an *implicit* payment for capacity above the short-run marginal cost of production.

Figure A.2
When Demand Is High, Price Spikes Provide An Implicit Capacity Payment



Dynamic efficiency occurs when resources are allocated efficiently over the longer term, including through the efficient choice of investments. A complete energy-only market will be accompanied by a liquid market for risk, which can deliver efficient investment in capacity. As noted above, the price of electricity in an energy-only market will tend to be volatile and to exhibit occasional price spikes. Generators and customers typically do not

⁶⁵ The mathematical proof of this proposition is long-winded but not complex. It can be found in a number of articles that describe the “screening curve”.

wish to be exposed to the full risks of this volatility, spurring the development of markets that allocate (“share”) the risks between different parties. Generators who want to secure the recovery of their costs will contract with customers seeking to minimise the risk of high prices, by signing contract for the sale and purchase of electricity at prices agreed in advance (day-ahead, week-ahead, month-ahead, year-ahead, and so on).

When forward markets are a well-developed means of managing risk, generators can observe price signals that indicate in advance the need for new capacity, and can respond by investing. If peak demand is nearing available capacity, then in the future power prices will be expected to rise and to become more volatile. The price of power agreed in forward contracts (and the value of options on these contracts) will then rise. Observing this signal, generators can respond by investing in additional capacity or by keeping older capacity online for longer, offsetting the required investment costs against a revenue earned from delivering energy at prices agreed through forward contracts. Conversely, if there is an abundance of capacity in the market, expected price levels and volatility will fall, signalling to generators that they should retire older units that are uneconomic. In either case, the market will tend towards an efficient outcome (albeit one constrained by the history of previous investment decisions).

A.2. In Practice, Market Failures May Prevent Energy-Only Markets From Reaching Efficient Outcomes

In practice energy markets may neither be complete nor competitive and energy-only markets do not necessarily result in efficient outcomes. Instead, deviations from these conditions may arise and are referred to as “market failure”.⁶⁶ Energy-only markets may not be *complete* if some goods and resources are not tradable, such as a secure supply of electricity in times of system stress. Similarly energy-only markets may not be *competitive* if limited market participation leads to prices that do not reflect the true cost or value of capacity. In practice, energy-only markets are unlikely to deliver an efficient level and mixture of generation capacities for a number of reasons. We list the typical sources of market failure below. These market failures lie at the heart of the reason for adding a capacity mechanism.

A.2.1. Reliability may constitute an incomplete market

In the future, it may be possible to offer every consumer the degree of reliability they are willing to pay for, by calibrating smart meters to disconnect each consumer only when the electricity price rises above a pre-programmed level. With current technology, however, reliable electricity supply has the features of a quasi-public good. It is “non-excludable” (system operators do not possess the means to exclude single users from the market, in response to their willingness-to-pay). It is also “non-rival” to the extent that reliability depends on centralised incentives for investment in generation capacity (in which case, receiving reliable service does not necessarily preclude another also receiving it).

⁶⁶ Note that in economics a “market failure” can only be judged by reference to the ideal standard of an efficient and competitive market, no matter what outcome might emerge from such an ideal. A market failure does not arise just because a market deviates from an outcome considered desirable by market participants or government bodies.

Economic theory suggests therefore that freely negotiated electricity prices will fail to reflect the full social value of reliability, leading to under-provision of capacity. This market failure can be addressed by ruling that electricity prices must rise to the social Value Of Lost Load (VOLL) in times of scarcity. However, as we discuss below, such rules face a number of practical obstacles and are unlikely to resolve the original market failure:

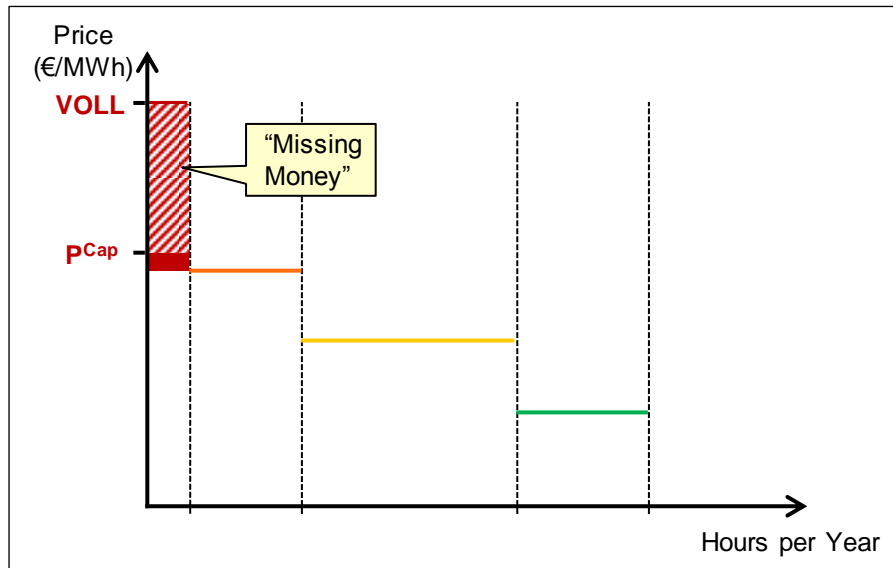
- **Political valuation of VOLL:** in order to provide the socially optimal level of reliability, prices must be allowed to rise to a level at which customers are indifferent between receiving a continued supply and suffering from their load being shed. However, customers do not typically participate in the wholesale energy market, and therefore the value they place on lost load must be determined by a regulator or similar body. The resulting value becomes a *de facto* price cap. VOLL has often been set by reference to surveys of consumers' willingness-to-pay, so that the level of VOLL approximates the bids that consumers would submit, were they to participate fully in the market. However, politicians and regulators tend to attribute a high (political) cost to outages in the short term, regardless of any long term implications for total (economic) cost of generation. Political (and regulatory) processes therefore tend towards minimising the cost of *losing* load, rather than minimising the cost of *meeting and losing* load, which would maximise social welfare. This tendency sometimes results in VOLL being set higher than the true social cost of load shedding. Such outcomes would provide inefficiently high scarcity rents to generators, and encourage inefficient (excessive) entry of new capacity into the market. However, in practice, such outcomes are unlikely.
- **Explicit price caps:** despite the high cost that political (and regulatory) processes tend to attribute to loss of load, regulators and politicians often aim to cap or prevent spikes in wholesale prices. Price spikes in energy markets are politically unpopular. In response, many energy markets impose explicit caps on the prices at which generators may offer to sell their energy.⁶⁷ Price caps can also arise *de facto* from rules that do not allow prices to reflect marginal cost, as is the case in the Great Britain Balancing Mechanism.⁶⁸ Low price caps create a “missing money” problem, because electricity prices do not provide the revenue generators need to recover costs. Specifically, if electricity prices never rise much above the short-run marginal cost of a peaking plant then such plants do not recover their fixed capacity costs (and other plants recover less than their total fixed capacity costs). Price caps therefore deter efficient market entry, leading to inefficiently low security of supply and/or more volatile energy prices.
- **Implicit price caps:** many energy-only markets do not have an explicit price cap. However, in practice regulators and politicians remain so averse to price spikes that they would intervene if prices ever rose near to VOLL. Generators therefore adjust their behaviour to ensure that electricity prices never rise high enough to reflect the true value of scarce capacity. Prices are *implicitly* capped by the threat of regulatory intervention in response to future price spikes. In some markets, generators may use market power to

⁶⁷ The Texas wholesale market, ERCOT, is capped at \$5,000/MWh and the PJM on the East coast of the United States is capped at \$1,800/MWh, to cite two examples.

⁶⁸ “Electricity prices do not currently reflect the value of scarcity due to how imbalance (“cash out”) prices in the balancing mechanism are calculated.” **Great Britain CPM Impact Assessment** (2013), *Electricity Market Reform – Capacity Market (update October 2013)*, Impact Assessment, DECC, 24 October 2013, page 7.

raise electricity prices at other times, so as to provide the revenue necessary to cover costs. However, such behaviour may be illegal under competition law and distorts incentives to select the correct generation mix. Implicit price caps and/or the reaction of incumbents can also inject risk and inhibit the ability of new entrants to recover the costs of their investment, thereby deterring efficient new entry.

Figure A.3
Price Caps Introduce A "Missing Money" Problem



The EC staff also identify that price caps create a market failure, leading to inadequately secure supply:

“Explicit or implicit wholesale price caps [...] (particularly if set substantially below reasonable estimates of the value of lost load) prevent the market from fulfilling its proper function of matching supply with demand in times of system stress.”⁶⁹

A.2.2. Lack of demand side response

Due to lack of real-time metering for most customer segments, demand for electricity does not respond to prices in the short term (i.e., in technical terms it is “perfectly inelastic”). This condition can result in inefficiency for two reasons:

- **Excessive volatility:** consumers are effectively unable to respond to prices that signal scarcity in the energy market. Faced with the volatile wholesale prices, large industrial users (and even households) might prefer to reduce their electricity demand in times of scarcity at a price lower (or even much lower) than the officially determined VOLL. Without this sensitivity to prices (“price-elasticity”), energy-only markets for electricity are subject to prices that spike too high and too often. This volatility increases the risks to cost recovery faced by generators, and hence the cost of capital for financing investment in generating plant. Ultimately, energy prices faced by consumers rise as a result.

⁶⁹ EC Staff Guidelines (2013), page 13.

- **Market power:** a highly inelastic demand curve facilitates the exercise of market power (setting prices above marginal cost). If wholesale markets are dominated by large generators, then they can exploit the unresponsive nature of electricity demand by offering to sell electricity at high prices. In this situation, demand is not met at least cost, if some generators withdraw cheap capacity and force the use of more expensive capacity.

A.2.3. Poor risk management tools

If markets for the physical supply of electricity are not accompanied by liquid contract markets, generators and customers will not be able to trade and to reallocate the risk associated with future energy sales. In illiquid markets, the prices of forward contracts and derivatives do not accurately reflect expectations of the future electricity price and its expected volatility. An energy-only market may then fail to provide adequate signals to investors of the future need for capacity.

A.2.4. Poor co-ordination of investment in small markets

Many of the problems highlighted above (limited market participants, lack of liquidity) are particularly likely to affect small markets which require investment in large, long-lived assets. Another problem in small markets is co-ordinating the required investment in capacity. In a small electricity market, a single, minimally-scaled addition of generating capacity may be large enough to accommodate demand growth for several years. Co-ordination problems may deter any particular market participant from making this investment (or may delay decisions to do so until high prices make the need apparent), for fear of over-investment that will be unprofitable for many years. This pattern of “lumpy” investment may exacerbate the long term volatility of energy prices, whereby long periods of shortage and high prices are required to prompt investment, which then produces a long period of excess supply and low prices.

An additional co-ordination problem that can afflict small markets with large, long-lived investment is premature capacity additions by a player with market power. Due to the long-lived nature of power plants (25 years or more), and the occasional need for new investment in a relatively small market, a player with market power can forestall entry by others by prematurely constructing new capacity before the price of capacity rises high enough to remunerate a new entrant.⁷⁰ With long-lived investment, this strategy can be supported as a credible threat by the incumbent. However, this leads to a lack of entry by competitors and investment that occurs “too often” (with energy sold by the incumbent at a price that is “too high”).

A.2.5. Practical experience

In the United States, the introduction of a CRM in areas such as the PJM and New England was motivated by the “missing money” problem created by explicit price caps. The political constraints on electricity prices (which emerged from older, regulated systems) were

⁷⁰ For a discussion of monopolist’s use of long-lived capital to forestall entry, see Eaton, C. B. and Lipsey, R.G. (1980), Exit Barriers are Entry Barriers: The Durability of Capital as a Barrier to Entry, *The Bell Journal of Economics*, **11**, pages 721-729.

therefore recognised overtly in the design of the electricity markets and their CRMs. In Great Britain, the upcoming introduction of a CRM is also motivated by the “missing money” problem, but is justified mainly by reference to implicit price caps due to the threat of regulatory intervention, and the illiquidity of forward markets.^{71,72}

A.3. Evidence of the Continuing Need for a CRM in the SEM

As noted earlier, there is currently surplus generating capacity in the SEM. However, in common with many electricity markets, the Single Electricity Market (SEM) suffers from market failures like those set out in Appendix A.2. The market failures identified would require a capacity remuneration mechanism that addresses the specific problems identified below, in order to ensure continued adequacy of supply

The market failures identified above mean that electricity prices in an energy-only market will not rise as high as VOLL at times of load shedding, when the value of capacity is greatest. This limit on energy prices at crucial times will cause investments in capacity to receive too little revenue (either in actual fact, or in expectation). The lack of revenue discourages investment in capacity, producing an inefficient trade-off between investment and security of supply, whereby load is shed too often. A CRM replaces the missing revenue, and encourages a more efficient level of investment. The resulting quality of service depends on the trade-off between the cost of investing in peaking capacity and the Value of Lost Load. Suppose a generator designed to meet peak loads has an annual fixed cost of €30,000/MW per year. It can cover this cost in an energy market with a low valuation of VOLL and a relatively high number of hours of lost load, for example if the market reaches €3,000/MWh in 10 hours per year. In a market with a high valuation of VOLL, it will cover its costs with relatively little lost load, for example if the energy price reaches €10,000/MWh in 3 hours per year. Different estimates of the cost and VOLL will give different levels of lost load. In every case, the revenue from selling energy at VOLL covers the cost of investing in enough peaking capacity to achieve the relevant level of lost load. However, if energy prices are prevented from rising to VOLL (or are expected to be capped below VOLL), the market must provide equivalent revenue from another source, or else investment will be inefficiently low. CRMs provide one source of revenue to replace the revenue that is missing from an imperfect energy-only market.

The current surplus of generating capacity does not indicate that a CRM is no longer necessary. The purpose of a CRM is to spread the cost of meeting peak demand over a wider range of periods, including some with a shortage of capacity and some with excess capacity. Simply removing payments without removing the market failure is an “opportunistic” form of regulatory intervention which will lead to under-compensation of past investment, as well as a heightened sense of regulatory risk and possibly even greater market failure. To be effective, capacity mechanisms must be stable and long-lived.

⁷¹ Great Britain CPM Impact Assessment (2013), page 11.

⁷² Great Britain CPM Impact Assessment (2013), page 1.

A.3.1. The current SEM has an explicit price cap and bidding rules, leading to a “missing money” problem

The Bidding Code of Practice requires generators participating in the Single Electricity Market to submit offers to generate electricity at their Short Run Marginal Cost (SRMC) of generation.⁷³ Generators must also submit accurate technical data for each individual unit, indicating the cost of starting it from a cold state, its ramp rate and the cost of running at a zero load factor. The System Marginal Price, which generators receive for their output, reflects the SRMC of the marginal (i.e., most expensive) unit called to meet demand in each half hour (plus any associated start-up, ramp-up or zero load costs). The System Marginal Price cannot exceed a price cap, currently set at €1,000/MWh. The price cap therefore also defines the maximum offer any generator can submit.

The Bidding Code of Practice is designed to mitigate market power in the small and highly concentrated Irish market but it, along with the explicit price cap, introduces exactly the “missing money” problem identified in Appendix A.2.1. The RAs currently estimate that VOLL is €10,898/MWh.⁷⁴ Assuming they have correctly measured VOLL, there is at least €9,898/MWh of “missing money” in the SEM during hours of load shedding. At some times, this shortfall will be even higher, if the Bidding Code of Practice requires generators to submit offer prices that are even lower.

The System Marginal Price in the SEM does not therefore recognize the social value of lost load. This market failure will lead to the under-provision of capacity and hence reliability. The EC would like the explicit price cap and the implicit constraint on generator offer prices to be removed, but that would expose the market to the exercise of market power. Assuming that (1) the RAs and other Irish government bodies have done everything they can to enhance competition in the electricity market and (2) that there are no other less distortionary remedies for competition problems, a CRM can provide a useful remedy for the failure to permit economic pricing of electricity at peak times, by providing generators with an alternative payment for capacity.

A.3.2. Regulatory risk means prices may be implicitly capped

In Ireland, as elsewhere, generators face the threat of regulatory intervention that places an *implicit* cap on energy prices. Such threats are undefined, but face generators at all times and constitute a permanent risk to their ability to recover their costs.

In the United States, legal obligations on regulators to ensure a reasonable prospect of cost recovery constrain the ability of regulators to behave opportunistically.⁷⁵ Just as importantly, administrative procedures for regulatory decisions are defined in long-standing laws, highly developed, open and predictable.⁷⁶ However, such principles and procedures are much less

⁷³ SRMC is defined in terms of opportunity cost - “the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.” Single Electricity Market Committee (13 March 2014), *Bidding Code of Practice*, paragraph 7.

⁷⁴ *Policy Parameters 2014*, Decision Paper, SEM Committee, 8 November 2013, page 13.

⁷⁵ See Supreme Court Decision in *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591 (1944).

⁷⁶ See Administrative Procedures Act 1946.

well developed in European electricity markets, including the Irish one, due to the relatively short-lived experience of liberalisation and privatisation. As a result, market participants in Ireland have less protection (than market participants in the United States) against potentially opportunistic regulatory or political intervention to lower customer bills.

Even if regulatory discretion has never actually been exercised opportunistically to date, the threat of such interventions can still prevent electricity markets from reaching an efficient outcome. The mere potential for opportunistic intervention may be enough to deter investment and to result in inefficient market outcomes.

In any case, the observed behaviour of regulators may gradually heighten or diminish the perception of regulatory risk. In this context, it should be noted that regulators in the SEM have proven willing to change established arrangements in ways that deny the recovery of costs that market participants were expecting to recover. For example:

- In 2010, the CER disallowed costs in the regulated retail segment that had been “legitimately incurred”, in order to keep end-user prices low.⁷⁷ The CER disallowed ESB PES’s “K-factor” (an adjustment for revenue over- or under-recovered in a previous price control) in its supply price control of 2011-12. The revenues lost as result of this decision were very significant: €178.3 million was disallowed, around 155 per cent of ESB PES’s regulated annual turnover.⁷⁸
- In 2011, the government in the Republic of Ireland introduced a new tax (the Carbon Revenue Levy or CRL) to claw back the value of EU ETS allowances passed through into electricity prices and given to the generators for free. The CRL was a variable (opportunity) cost of generation, but the CER directed generators not to include it in their bids into the SEM. Ultimately, two generators went to the Supreme Court in order to get the decision overturned and to be allowed to recover their costs.⁷⁹ The legal costs associated with challenging this decision were recovered and, importantly, the Supreme Court agreed with the generators that the costs of the CRL were to be included in all future bids by generators into the SEM. However, the financial costs of the previous illegal decision by the CER (incurred over the historic period of the CRL) were not recovered.
- In 2013, SEM Committee reviewed and revised its interpretation of how the gas transport costs paid by generators were reflected in their offer prices in the SEM. The CER then published a decision to force the gas transmission company to withdraw within-day tariffs for the sale of exit capacity.⁸⁰ That decision (in conjunction with another decision limiting secondary sales of exit capacity to generators) would have made it impossible for generators in the Republic of Ireland to include the cost of gas transmission exit capacity in their offer prices (which would have prevented some generators from recovering these

⁷⁷ **ESB Price Control Decision** (2010), *Decision on ESB PES’s Supply Price Control 2011-2012*, CER, CER 10/182, 13 October 2010, page 19

⁷⁸ **ESB Price Control Decision** (2010), pages 17-18.

⁷⁹ See description of the case in Shuttleworth, G., and Anstey, G. “Irish Supreme Court Restores Common Sense to the Electricity Market”, *Electricity Journal*, **25**, Issue 5, June 2012, pages 36-42.

⁸⁰ *Access Tariffs and Financing the Gas Transmission System*, CER, CER 13.191, 21 August 2013.

costs). In February 2014, the CER reversed this decision, but not for reasons connected with protecting generators' ability to recover costs.⁸¹

It is therefore difficult to argue that the SEM is insulated from any perception of regulatory risk and the resulting market failure. On the contrary, the SEM appears to be prone to regulatory interventions that deny cost recovery, like many other European electricity markets. In addition, the all-island market currently includes an explicit payment for capacity. Removing this element from the design of the reformed SEM would increase the perception by market players of regulatory risks to cost recovery. Therefore, continuation of the CRM (in some form) is likely to be justified – or even required – to avoid introducing further regulatory risk and market failure.

The decision to add a CRM to the energy market of the SEM was intended to enhance the credibility of investment incentives, by providing a form of capacity remuneration that was more stable in the long term. The CRM's design seeks to exchange volatile peak pricing signals for lower and more stable energy prices, augmented by a stable capacity payment. The CRM's purpose would be undermined, and the credibility of long term incentives weakened, if the RAs adopted a policy of introducing a CRM during any period of anticipated capacity shortage (thereby capping energy prices and limiting returns to investment), and removing the CRM during any period of anticipated capacity surplus (whilst letting energy prices fall and reducing returns to investment).

A.3.3. There is little liquidity in forward markets

The SEM is a gross pool, through which all major generators sell, and suppliers purchase, all the electricity generated to meet total demand. A forward market has developed to manage the risk around future price levels in this market through the trading of “contracts for difference” (CfDs). If the System Marginal Price exceeds the strike price agreed in these CfDs, the generator makes a payment to the supplier equal to the difference in price *times* the contract volume. Conversely, if market prices fall below the strike price, the supplier compensates the generator. The net effect of the CfD working alongside the SEM is to stabilise the total payment from supplier to generator.

The RAs oblige both ESB and Power NI to offer a certain quantity of their output in advance through “directed contracts”. They and others also trade in “non-directed” CfDs. The RAs last reviewed the liquidity in this market in 2010, when they found that traded volumes of CfDs of all sorts had fallen by approximately 30 per cent since the levels observed in 2008/09 (although some of this fall may be explicable by the fall in total demand over the period).⁸² A more revealing measure may be the “churn rate” – the volume of electricity traded forward as a proportion of delivered electricity. The RAs found that the SEM had a churn rate lying

⁸¹ *CER Decision on Gas Access Products and Tariffs*, Notification to Industry, CER, 20 February 2014. The CER's grounds related to the level of revenue that the gas transmission company was managing to collect from gas-fired generators, among others.

⁸² **SEM Market Power** (2010), *SEM Market Power & Liquidity – State of the Nation Review: An Information Paper*, SEM Committee, SEM-10-057, 23 August 2010, page 43.

well below one, compared to six in the Nordpool market and three in the Great Britain market.⁸³

The available evidence therefore suggests that the forward market for electricity sold in the SEM is likely to be illiquid and uncompetitive, a market failure which can be addressed by a CRM. A CRM cannot make a market liquid or competitive, and the forms of CRM that rely on capacity trading would be subject to the same problems. However, some forms of CRM can substitute for a liquid and competitive forward market by providing generators with a more predictable and stable stream of future income, reducing the risks they face and hence the cost of financing new investment.

A.3.4. Potential for market power

As noted in Section 2.1.3, there is one player (ESB) that is potentially dominant in the all-island generation market. Dominant players inhibit competitive markets reaching socially optimal outcomes, a market failure. In the SEM, this failure of competition can work through several channels. As outlined in Appendix A.2.2, since the demand curve for electricity is highly “inelastic” there is potential for the dominant player to unduly influence energy prices. Since ESB accounts for 46 per cent of generation, it is highly likely that its bids will determine the System Marginal Price in many trading periods. By bidding above (or below) the marginal cost of production, the dominant player can exert effective influence over energy prices.

The Bidding Code of Practice is a measure designed to mitigate this market failure. However, it does not remove it. In this case, since ESB is state-owned, the perception by market participants that it may follow non-commercial incentives can compound this market failure. State-owned companies (even those run at arm’s length) are often perceived to have non-commercial motives, for example minimising wholesale prices. A dominant state-owned company can provide an effective cap on energy prices, by providing electricity at less than its marginal cost. If market participants perceive there to be a risk that dominance will be exerted in this way, then this provides an additional implicit cap on prices (since all believe that the dominant firm will act to lower prices if they rise too high).

A.3.5. The “small market” problem is pronounced in the SEM

Problems arising from the size of the SEM were part of the original justification for a CRM in Ireland (as described in Section 2.1.1 above). Although it is not a source of market failure in itself, the size of the SEM is likely to exacerbate any failures that are present in the energy market. In particular, the minimum efficient scale of a CCGT plant constructed in Great Britain is now about 900MW, and the minimum efficient scale of an OCGT is about 565MW, according to the analysis relied on by DECC to calculate the levelised cost of generation.⁸⁴ The Irish RAs use a 202MW OCGT as their benchmark for the “best new entrant” peaking

⁸³ SEM Market Power (2010), page 50.

⁸⁴ Parsons Brickerhoff (April 2013), *Electricity Generation Cost Model – 2013 Update of Non-Renewable Technologies*, Appendix A, pages 31, 46.

plant in the all-island market.⁸⁵ In Great Britain a 900MW CCGT represents 1.6 per cent of peak demand.⁸⁶ By contrast, in the SEM this would represent 13.9 per cent of peak demand.⁸⁷ Even a 202MW OCGT represents 3.1 per cent of peak demand.

The size of the SEM is likely to give rise to problems coordinating investment in new capacity, and “lumpy” investment may give rise to volatile prices. Volatile prices, in turn, compound the regulatory risks faced by generators and increase the cost of financing investment. In these conditions, a CRM can smooth the profile of prices earned by generators, by spreading payments that would otherwise occur only occasionally in peak hours over a larger number of peak, near-peak and off-peak hours.

A.4. Conclusion

Our instructions from Viridian asked us to review the case for a CRM in Ireland, based on the underlying economics of the system and the EC requirements. We have focused on the EC’s criteria for assessing State Aid, which can be summarised as the need to demonstrate a market failure that gives rise to a generation adequacy problem that cannot be addressed by strengthening the energy-only market.

The presence of an explicit price cap in the wholesale electricity market (coupled with a Bidding Code of Practice that prescribes SRMC bidding) is a demonstrable failure in the energy market to reflect the value of reliable electricity supply (VOLL). Removing the explicit price cap would leave an implicit cap price in place. Removing the explicit and implicit price caps would leave the market exposed to market power, which the RAs have made every effort to minimise.

The real and perceived regulatory risks to cost recovery are likely to exacerbate the problem of under-investment, even if the price cap is removed in the reformed energy market. An illiquid forward market that cannot provide adequate investment signals, and the problems of coordinating large and long-lived investment on a small island (especially in the presence of market power as described in Appendix B.3), provide further evidence of potential market failures in the SEM.

If the SEM relied on an energy-only market, these market failures would result in a generation mix that is neither allocatively nor dynamically efficient, a situation the RAs recognised in 2007 when deciding to introduce a CRM. In their Mid-Term Review in 2012, the RAs implicitly confirmed that these market failures were still in place, since they saw “no compelling need to make major changes to the current design and methodology” of the CRM.⁸⁸ We do not have any reason to think that the market failures recognised by the RAs in 2007 and 2012 are no longer present in 2014. To the extent that these market failures are well understood, have already received the concerted attention of the RAs and there are no

⁸⁵ *Fixed Cost of a New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2013*, SEM Committee, May 2012, page 20.

⁸⁶ Peak demand of 55,550 MW for winter 2013/14 taken from Ofgem, *Electricity Capacity Assessment Report 2013*, Appendix 1, page 64.

⁸⁷ Peak demand of 6,473 taken for 2014 from Eirgrid, SONI (2014), *All-Island Generation Capacity Statement- 2014-2023*, Appendix 1, page 61.

⁸⁸ *CPM – Medium Term Review* (2012), page 3.

alternative remedies available to them, a CRM remains a necessary feature of the reformed SEM.

Appendix B. High-Level Design Questions

On the assumption that economic efficiency requires the SEM to incorporate some kind of CRM, Viridian asked us to questions about the design of the CRM, focusing on the following areas:

- **The coverage of the scheme:**
 - The EC and ACER consider explicitly whether the scheme should be a targeted “strategic reserve” or a “market-wide” payment. What are the likely economic effects of a strategic reserve, particular the displacement of other investment and the distortions that targeted payments can introduce, for comparison with the economic effects of a market-wide solution?
- **Provision of efficient exit signals:**
 - Can efficient exit signals (e.g. rewarding more flexible and reliable plant) be incorporated into a price-based mechanism, and if so how?
- **Possible abuses of market power in a CRM:**
 - Given the existence in Ireland of a dominant player that is state-owned and has “deep pockets”, how and to what extent could it use its market power to reduce payments to capacity (and to squeeze out competitors) if capacity payments are determined by an auction or other market based mechanism?
 - Describe a predatory pricing strategy that could be employed by a dominant player; and in what conditions would it be economically rational, if any?
- **Compatibility of the CRM with market coupling under the EU Target Model:**
 - From an economic perspective, what changes would need to be made to the current CRM in the SEM to make it compatible with market-coupling under the EU Target model, in the light of the state aid guidelines?

B.1. Coverage of the Scheme

The first step in the RA’s taxonomy divides CRM designs according to the coverage (or “scope”) of the scheme. CRMs can either be “market-wide”, covering the capacity of all power generators, or “targeted”, i.e., only remunerating the capacity of specific generators to be used only during times of system stress.

B.1.1. The EC’s favourable statements about strategic reserve betray a misunderstanding of economics

In a recent working document, the staff of the EC discuss the coverage of a CRM.⁸⁹ The EC Staff express favourable views towards a targeted “strategic reserve” mechanism. They accept that, “where strategic reserves are used to keep prices low, [... it is] not only not cost-effective but risks seriously distorting the internal market.”⁹⁰ However, they state that

⁸⁹ EC Staff Guidance (2013).

⁹⁰ EC Staff Guidance (2013) page 22.

procuring strategic reserve (to be employed in emergency events) does “not affect the market during normal periods”.⁹¹ Similarly, in the SEM Consultation, the RAs suggest that capacity traded as strategic reserve has limited “consequences [on] the wider energy market”.⁹²

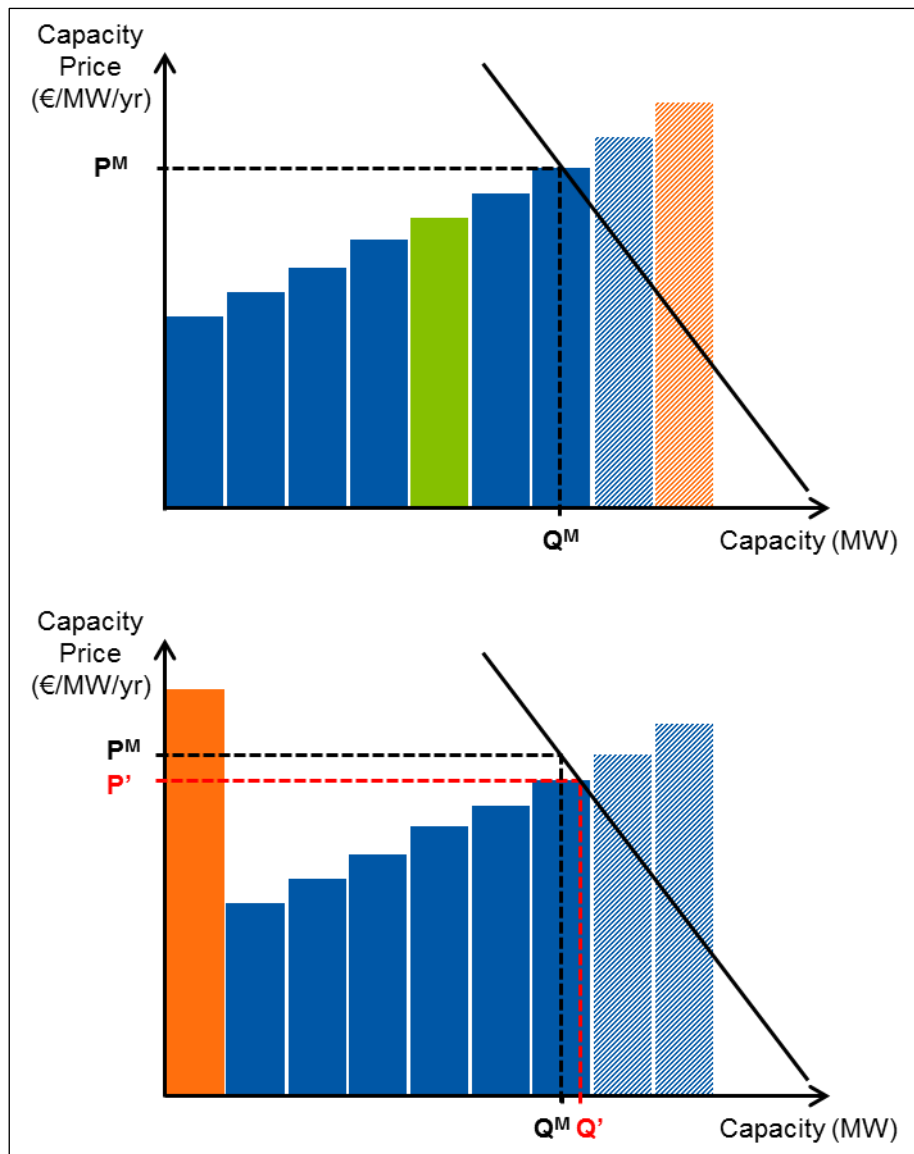
The view that strategic reserve helps generator adequacy without distorting electricity markets is based on a fundamental misunderstanding of the economics of electricity systems, and the role played by strategic reserve. In the short term, targeted schemes can attract new investment in capacity, and increase security of supply. However, in the long term, targeted schemes displace generation that would otherwise have been built, depressing prices but raising total costs. Strategic reserves therefore do little to aid generator adequacy, but do distort the selection of generator capacity.

Figure B.1 illustrates how strategic reserve affects the wider market. The first diagram illustrates the equilibrium level of capacity in an energy-only market, Q^M , where long run demand for capacity (the downward sloping black line) meets the long run cost of new entry (represented by discrete blocks of capacity available at different costs). In the equilibrium, the price of capacity settles at the level needed to cover the cost of the marginal unit (P^M). Procuring strategic reserve that is “in merit” (such as the block shown in green) does not affect this outcome. While this provides an additional revenue stream for the generator, it does not alter the price of capacity or the quantity supplied. Figure B.1 also shows the effect of contracting with a generator that is “out of merit”, i.e., which costs more than P^M (the block shown in orange). Procuring this strategic reserve puts it at the head of the supply curve, shifts other capacity to the right and causes a slight fall in market prices (to P'), which in turn may bring forth a slight increase in capacity (to Q'). However, the most important effect is to displace other, cheaper forms of generation that would be “in merit” in normal market arrangements. Procuring strategic reserve therefore raises the total cost of generation, in return for only a slight change in generator adequacy.

⁹¹ EC Staff Guidance (2013), page 22.

⁹² I-SEM – High Level Design (2014), page 101.

Figure B.1
Targeted CRMs Distort The Wider Market



B.1.2. Other policy-makers have recognised the distortionary effects of strategic reserve

When considering options for introducing a CRM in 2011, DECC published an assessment of strategic reserve versus a market-wide mechanism. It ultimately decided against implementing a strategic reserve, noting that:

- strategic reserve “does not deal with the fundamental problem of ‘missing money’”, in that it does not mitigate the effect of explicit or implicit caps on wholesale prices.⁹³

⁹³ GB CPM Impact Assessment (2011), *Electricity Market Reform – Capacity Mechanism*, Impact Assessment, DECC, 15 December 2011, page 43.

Therefore, a strategic reserve system does not address the specific market failure which gives rise to the need for a CRM.

- plants not selected as reserve might shut down, leading to a “slippery slope”, where “more and more plant must form part of the reserve to ensure it remains effective”.⁹⁴ This risks “crowding out” efficient investment.
- strategic reserve was unlikely to be technology neutral, as there was little incentive for demand-side response to participate.

NordREG, the group of Nordic Energy Regulators, was similarly critical of the effects on the wider market of TSOs in Sweden and Finland procuring strategic reserves. They agree with the analysis presented in Figure B.1, that “the use of peak load resources [i.e., strategic reserve] is likely to lower the prices in the market”, and that this does indeed create a “slippery slope” where “the incentive to invest in peak load power plants decreases”.⁹⁵

B.1.3. Strategic reserve addresses the problem of generation flexibility, not adequacy

The EC and RAs favour targeted mechanisms in a context for which they are not suited, because of a misunderstanding of the distinction between the functions of market-wide and targeted schemes. Capacity markets are targeted at a *generation adequacy* problem, and mitigating the market failure which means there are insufficient returns to providing capacity. Such schemes must address the incentives to make or to keep capacity available across the market as a whole. Targeted schemes can work to solve a *generation flexibility* problem, where the problem to be solved is not the volume of generation *per se*, but selecting the “right kind of capacity” – e.g. flexible capacity – because the market as a whole cannot provide incentives that distinguish between types. For example, in Britain, the Short Term Operating Reserve supports capacity able to start and stop very quickly (more quickly than a half-hourly price can indicate) and located in particular parts of the network (beyond what general transmission tariffs can achieve).

B.2. Provision of Efficient Exit Signals

This section discusses the provision of efficient exit signal in the design of any CRM and addresses the following question put to us by Viridian:

- *Can efficient exit signals (e.g. rewarding more flexible and reliable plant) be incorporated into a price-based mechanism, and if so how?*

To answer this question, we consider what exit signals are efficient, and how these can be incorporated into a CRM.

⁹⁴ GB CPM Impact Assessment (2011), page 36.

⁹⁵ NordREG (2009), *Peak Load Arrangements – Assessment of Nordel Guidelines*, page 15.

B.2.1. CRMs are designed to induce efficient entry into, as well as efficient exit from the market

CRMs are a measure that relieve a generation adequacy problem by providing a payment to available capacity, not a payment based on a characteristic of that capacity (i.e., flexibility). The draft EC guidelines are clear that a CRM is a measure that should be targeted at a “generation adequacy” problem, and that an “appropriate” measure should be open to all technologies that can mitigate the problem (presumably including both flexible and inflexible generators). In most markets, generation adequacy problems arise from a lack of efficient entry. Therefore, CRMs are typically aimed at ensuring there is enough new capacity (either flexible or inflexible) to guarantee security of supply.

However, the legacy of historical investment decisions may mean that the amount of capacity in the market exceeds the efficient level. In these circumstances it is efficient for plant with high costs to retire, when the on-going costs of continued operation exceeds the social benefits of doing so. These circumstances are likely to be relevant to the SEM, where a capacity margin of 30 per cent or greater is forecast to persist until 2018 (and thereafter margins are forecast to remain above 10 per cent until 2023).⁹⁶

CRM design may prevent efficient exit, for two reasons:

- **Capacity price exceeds social benefit:** the price that generators receive per unit of capacity is too high, such that it exceeds the marginal social benefit of additional capacity. This can occur in a poorly designed CRM (either price or quantity-based), where the regulator sets a fixed price for capacity (or fixed quantity to be procured) that exceeds the optimum level needed to guarantee security of supply. Although the capacity payment may offer remuneration in excess of the social benefit of capacity in the near future, the regulatory authorities must have regard to the wider social benefits of the CRM design. The objectives of a CRM are to provide a stable and reliable capacity payment in exchange for reducing the volatility and level of peak energy prices. Reducing remuneration available through the CRM may threaten this regulatory compact, increase risk for investors, the volatility of prices, threaten future investment and cause plant to exit the market.
- **Ineffective monitoring:** in markets that have a large surplus of capacity (such as the SEM), there may be a number of peaking generators that receive a capacity payment for making themselves available, but are never actually required to generate. Indeed, the plant may not be reliable and/or flexible enough to do so – a situation which can persist if there is ineffective monitoring. These generators are effectively “free riders” who enjoy the benefits of capacity payments without bearing the cost of making their plant available. Nonetheless, the presence of these “free riders” will depress capacity prices without providing a commensurate security of supply benefit. In principle the problem of so-

⁹⁶ Eirgrid, SONI (2014), *All-Island Generation Capacity Statement- 2014-2023*, pages 61, 71.

called “zombie” capacity can occur in price or quantity based mechanisms, and has frequently been referred to in respect of the quantity-based ISO-NE market.⁹⁷

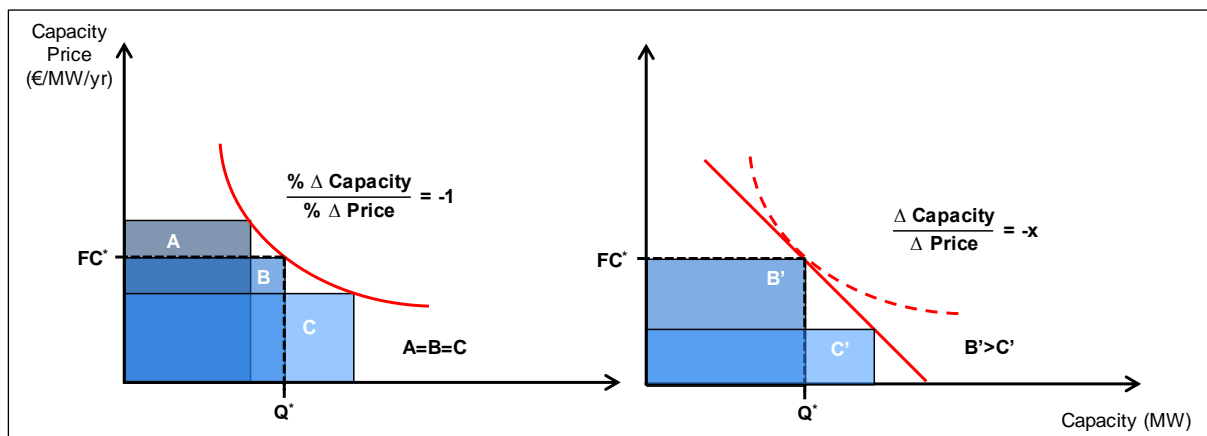
B.2.2. Aligning the demand curve and social benefit of capacity

An electricity system may have an inefficiently high quantity of capacity on the system if the price of capacity under the CRM exceeds the marginal social benefit. In principle, this can occur in any CRM design.

We illustrate the concern in the case of the current design used in the SEM on the left hand side of Figure B.2. The total capacity payment to all generators each year is invariant to the actual amount of capacity that is actually available (the areas A, B, and C are all equal). Therefore, when there is an oversupply of capacity (as is the case in C) price falls very slowly in response to excess supply, possibly leading to an over-payment of generators and inefficiently low exit from the market. In practice, the current CRM used in the SEM has a demand curve that is very flat (“price elastic”), even at high levels of capacity.

By contrast, US based mechanisms typically involve a demand curve that has a price of zero (or a low floor price) at some level of capacity (illustrated with the red line on the right of Figure B.2). This demand curve can be incorporated into a “payment-based” mechanism, by reducing the total payment level in response to the amount of generators in the market.

Figure B.2
Altering the Slope of the Demand Curve Can Reduce “Free Riding”, But May Introduce Regulatory Risk



The design of any CRM must solve the market failures identified in the local market and the example of demand curves used in the US may provide a cautionary example against adopting designs successfully applied elsewhere wholesale. In the context of a small market like the SEM, increasing the slope of the implicit demand curve could defeat the object of the capacity mechanism itself. One of the principal motivations for having a capacity payment in

⁹⁷ ISO New England Inc. and New England Power Pool submission to the FERC (27 February 2014), *Motion For Leave To Answer And Answer Of The New England Power Pool Participants Committee*, http://www.nepool.com/uploads/Filing_20140227_ER14_1050_NEPOOL_Answer.pdf

the SEM is that, as a small market, it might otherwise be subject to spikes and troughs in prices as new capacity was retired or added to the system. For a capacity market to smooth prices in the SEM, the (implicit) demand curve for capacity must decline only gradually. Indeed, steep demand curves also increase the scope for the exercise of market power (as we note in Appendix A.2.2).

Moreover, as noted in Appendix A.3 above, whilst there is currently surplus generating capacity in the all-island market, that does not justify removing capacity payments through introducing a steeply sloped demand curve. Such an “opportunistic” form of regulatory intervention will heighten regulatory risk, and exacerbate the market failure a CRM is designed to address.

B.2.3. Verification and Testing

To avoid the problem caused by ostensibly available capacity that does not in fact contribute towards security of supply (“free riders”), a well-designed CRM should also include tough verification standards. Verification that capacity is actually available and generating is an important issue in CRM design, due to the increased role demand-side response is forecast to play in ensuring generation adequacy, as well as the legacy of older thermal plant that is rarely (if ever) called on to generate. Monitoring regimes to alleviate this problem are compatible with either a price-based or quantity based CRM and are used in many US, quantity-based regimes.

- **Forced Testing:** Markets that incorporate CRMs often have well developed forced-testing regimes. For example, in the PJM market generators are obliged to report the net capacity of each unit in both summer and winter. Units that normally generate during the course of both seasons can submit operational data. Units that are not normally called on to generate must conduct an annual test to verify their capability, and submit this to the system operator.⁹⁸ In practice, and depending on the capacity available in the market, more frequent testing may be required to ensure that capacity is actually available in the Irish context. While forced testing incurs costs, this or some other compliance mechanism, which would also incur costs, is a necessary feature of any CRM.
- **Penalty regimes:** The problem of ostensibly available generation can, in principle be resolved in quantity-based mechanisms through the imposition of penalties for not generating at peak times. For example, the British CRM will auction off agreements to provide capacity (with delivery from 2018 onwards). The agreement places an obligation on the holder to generate (or reduce demand) at times of system stress following a “capacity market warning”. Failing to fulfil the agreement is associated with a stiff penalty. In its most recent impact assessment, DECC outlined plans to impose a £3,000/MWh (€3,600/MWh) penalty on generators that fail to meet their obligation.⁹⁹ However, penalties are only likely to be an effective measure if they present a real risk to generators: If certain generators are never required to generate, because they are never or

⁹⁸ See PJM (5 March 2014), *Manual 21 - Rules and Procedures for Determination of Generating Capability*, Appendix A, page 15.

⁹⁹ **Great Britain CPM Impact Assessment** (2013), pages 32, 69-70.

rarely in-merit, even in peak times, penalties for failure may not incentivise units to exit the system. As a result, units may continue to free-ride by lingering on the system and picking up capacity payments.

The method used to incentivise generators to provide capacity need not be uniform across all unit types. In practice, a CRM is designed to provide a balance of risks and incentives which incentivise the provision of capacity. The ability of generators to respond to those incentives varies, as does their ability to shoulder the risks of potential penalties. CRMs that remunerate intermittent generators, for example, must recognise the fact that their availability varies with time. Currently, intermittent generators in the SEM receive a capacity payment based on their production in a given period (since wind generators, for example, dispatch their entire available capacity). An alternative model, as used in the ISO New England capacity mechanism, is to make a payment to intermittent generators based on their de-rated capacity.¹⁰⁰ There is currently no penalty in the New England CRM associated with intermittent generators failing to fulfil the obligation.

B.3. Abuse of Dominance

This section discusses possible ways in which a CRM can be used by a dominant market player to abuse its dominance, and answers the following questions put to us by Viridian:

- *Given the existence in Ireland of a dominant player that is state-owned and has “deep pockets”, how and to what extent could it use its market power to reduce payments to capacity (and to squeeze out competitors) if capacity payments are determined by an auction or other market-based mechanism?*
- *Describe a predatory pricing strategy that could be employed by a dominant player; and in what conditions would it be economically rational, if any?*

B.3.1. Setting artificially low prices is an abuse of dominance under EC law

EC law prohibits firms that are dominant in a particular market from abusing their position, including “directly or indirectly imposing unfair purchase or selling prices”.¹⁰¹ “Predatory pricing” is one way in which a dominant firm use “unfair” prices to abuse its dominance. The EC considers a dominant firm to be abusing its position in this manner when it:

“engages in predatory conduct by deliberately incurring losses or foregoing profits in the short term (referred to hereafter as ‘sacrifice’), so as to fore-close or be likely to

¹⁰⁰ For the purposes of the capacity market, intermittent capacity is de-rated to the median output level observed in the previous five years, during certain “reliability hours” in summer and winter. See ISO New England (May 15 2012), *Overview of New England’s Wholesale Electricity Markets and Market Oversight*, page 7; *Market Rule 1*, pages 51-52, Section III.13.1.2.2.2.1.

¹⁰¹ Treaty on the Functioning of the European Union - PART THREE: UNION POLICIES AND INTERNAL ACTIONS - TITLE VII: COMMON RULES ON COMPETITION, TAXATION AND APPROXIMATION OF LAWS - Chapter 1: Rules on competition - Section 1: Rules applying to undertakings - Article 102 (ex Article 82 TEC).

foreclose one or more of its actual or potential competitors with a view to strengthening or maintaining its market power, thereby causing consumer harm.”¹⁰²

Identifying this sort of behaviour is difficult, but the EC requirements imply (at least) the following tests.

- **Dominance:** A dominant firm is able to “behave to an appreciable extent independently of its competitors, its customers and ultimately of consumers”.¹⁰³ Market share is used as a first indication of dominance by the EC. Firms with a market share of greater than 50 per cent are routinely regarded as “dominant” in EU competition law, while firms with a market share less than 40 per cent are unlikely to be considered dominant.¹⁰⁴
- **Sacrifice:** A dominant firm engages in “sacrifice” when it expands output to such an extent (or charges prices that are sufficiently low) that it incurs losses that could have been avoided.¹⁰⁵ If prices are set below *average avoidable cost* (a proxy measure for short-run marginal cost), then the dominant firm will incur a loss that could have been avoided by supplying no output at all.¹⁰⁶
- **Anti-competitive foreclosure:** Foreclosure occurs when the dominant firm’s behaviour depresses prices to the extent that an equally efficient firm cannot compete in the market, because it will be unable to recover its costs. The EC states that this can be assessed by whether the dominant firm is pricing below *long-run average incremental cost* in the industry (a proxy for long-run marginal cost).¹⁰⁷ Demonstrating that anti-competitive foreclosure has taken place does not require the dominant firm to have actually forced its rivals to exit, or that showing that it intends to recoup its sacrificed profits in the future. All that is required is that as a result of predatory behaviour the dominant firm can expect to increase its market power, whether this is from inducing exit, deterring entry, or merely disciplining rival firms to follow its lead when setting prices.

Predatory behaviour is easier to identify and monitor in an energy market than in a capacity market, since the variable cost of producing electricity is well understood. Predators offer to generate electricity at less than the short run marginal cost of generation. The Bidding Code of Practice rules out this behaviour in the all-island energy market in principle, provided that

¹⁰² EC (24 February 2009), *Guidance on the Commission's enforcement priorities in applying Article 82 of the EC Treaty to abusive exclusionary conduct by dominant undertakings*, (2009/C 45/02), paragraph 63.

¹⁰³ EC (24 February 2009), (2009/C 45/02), paragraph 10.

¹⁰⁴ See the often-quoted judgement in the AKZO case: ECJ, Case C-62/86 [1991] ECR I-3359, [1993] 5 CMLR 215.

¹⁰⁵ EC (24 February 2009), (2009/C 45/02), paragraph 64.

¹⁰⁶ The EC’s criteria is closely related to the so-called Areeda-Turner rule, which states that:

- Pricing above average total costs is not predatory;
- Pricing below average total costs may be predatory, depending on the intent of the alleged predator; and
- Pricing below marginal cost (measured as average variable cost) is presumed to be predatory, unless explicitly justified.

See Areeda, P. and Turner, D.F., (1975), *Predatory Pricing and Related Issues Under Section 2 of the Sherman Act*, *Harvard Law Review*, **88**, pages 697-733. Average variable cost will, in general, equal average avoidable cost (since variable costs are avoidable). However, if the dominant firm incurs additional fixed costs to increase output, then these costs are also avoidable, and AAC will lie above AVC.

¹⁰⁷ EC (24 February 2009), (2009/C 45/02), paragraph 67.

it is rigidly enforced. Predation in a capacity market may be more difficult to detect, because it requires the regulator to identify the net avoidable cost of capacity during the delivery period, including forecasting the generators' *anticipated* future costs and revenues. The difficulty of detecting predatory behaviour in capacity markets may contribute to the strict regulation of bidding, including setting minimum offer prices, in US capacity markets (see description in Section 5.4, above).

A capacity market (a “quantity-based” mechanism) may present a more difficult problem for monitoring predatory behaviour. The marginal cost of capacity to a generator in a capacity auction is its *net going forward costs*, the difference between a generator's estimated revenues from energy sales and its estimated costs in the period of delivery (the “missing money” owed to the generator). In principle, the same problem could affect a “price-based mechanism”, in which a predator could depress prices by investing in excess capacity.

In principle, the conditions for abuse of dominance may exist in an all-island CRM. As we noted in Section 2.1.3, ESB is the major player in the all-island wholesale market with a share of the generation of 46 per cent.¹⁰⁸ ESB could “sacrifice” profits by offering to supply capacity in a CRM at a price below its average avoidable cost. This might result from ESB's non-commercial incentives leading it to under-recover its costs (it is state-owned).

In practice, the viability of predatory strategies will depend largely on their cost, which is determined by the demand curve for capacity rather than the form of CRM (whether it is a price- or quantity-based mechanism). Vertical demand curves will tend to make predatory strategies easier to implement, because a relatively small increase in investment by the dominant firm may crash the price of capacity.

B.3.2. An economically rational predatory pricing strategy

In the context of a CRM, a predatory pricing strategy requires a dominant firm to deliberately depress the price of capacity to artificially low levels. In a quantity-based mechanism, this involves submitting offers to supply capacity at less than the commercially rational price, in order to induce exit by rivals. (Equally, in a price-based mechanism, making available more capacity than is commercially rational, either through new investment or delayed retirement, would have the same result). A predator charges low prices today to achieve high prices tomorrow, because rivals exit the market or potential rivals are deterred from entering the market. Alternatively, if the dominant firm is not maximising profit, e.g., a state-owned firm that aims to minimise wholesale (and hence end-user) prices, then low prices could continue indefinitely, creating a climate that is unattractive to new investment.

“Deep pockets” alone does not guarantee that predatory pricing will force rivals out of the market, which is only economically rational in the presence of imperfect financial markets (or imperfect information). In theory, the rival firms can explain to their lenders the losses they are currently suffering are a temporary phenomenon, and secure more funding in order to remain in the market. Knowing this, a dominant firm would likely not engage in predatory pricing in the first place. Imperfect information in capital markets is necessary for a successful predatory strategy. In practice, the predator's behaviour affects a lender's

¹⁰⁸ ESB (2014), *Annual Report and Accounts – 2013*, page 9.

evaluation of the smaller rival by reducing its profitability. Since the lender is not perfectly informed about the industry, and its future prospects, this places a credit constraint on small rivals that may force them to exit.¹⁰⁹

Rational firms only sacrifice profits in the short run if they believe they will secure greater profits in the long run. In the context of a CRM, this might come about for two reasons:

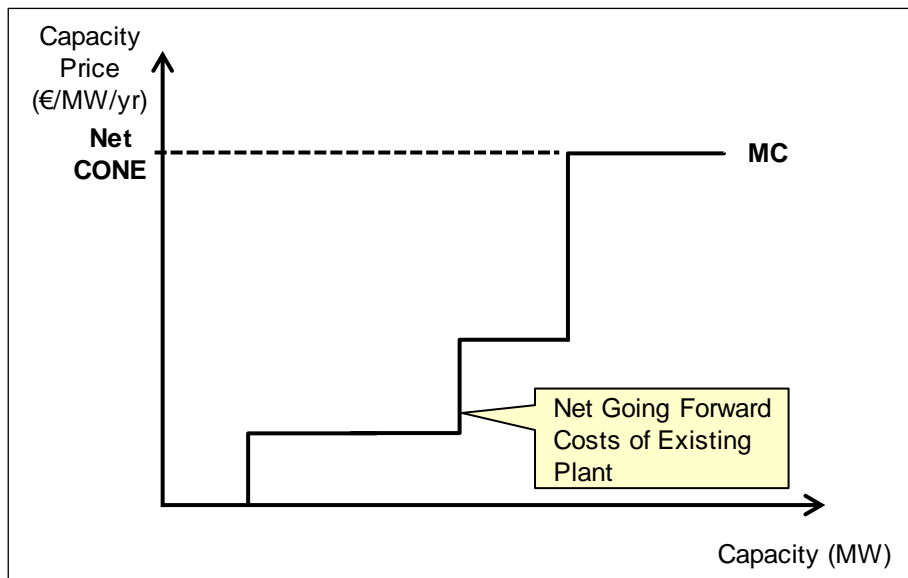
- **Dominance in the energy market:** offering to supply capacity at less than the net going forward cost of capacity may force rivals to exit the market. The increased market power enjoyed by the dominant firm allows it to offer to sell electricity at prices above its marginal cost. However, in the SEM the Bidding Code of Practice rules out this sort of behaviour in the energy spot market.
- **Dominance in the capacity market:** the supply curve in a capacity market will typically reflect the (low) costs of existing capacity and the (high) costs of new capacity.¹¹⁰ If a dominant firm can induce exit of rivals (or prevent entry), then it may be able to exert market power by offering to supply its existing capacity at just below net CONE. In the Great Britain capacity mechanism, this sort of behaviour is explicitly prohibited by the rule which distinguishes between “price-takers” (existing plant) and “price-makers” (new entrants).¹¹¹ Price-takers are required to bid at no more than 50 per cent of net CONE.

¹⁰⁹ See Motta, Massimo (2004), *Competition Policy – Theory and Practice*, CUP, pages 415-423. Since the cost structure of electricity generation assets is well known, it is unlikely that imperfect information about the dominant firm’s costs will allow predatory pricing to persist.

¹¹⁰ A competitive supply curve for capacity reflects the “net going forward cost” of source of capacity, which is the difference between the fixed and variable costs of operating a plant and the revenue it receives in the energy market. Existing plant which are “in merit” will typically have low or negative “net going forward costs”, since the infra-marginal rent they earn in the energy market covers their costs. Existing plant which are “out of merit”, such as peaking plant, may not cover their fixed costs, leading to a positive “going forward cost”. The most expensive point on the supply curve is the cost of constructing new plant (“Net CONE”). This last concept is that used by the RAs when determining the fixed costs of a best new entrant peaking plant– these are the “net going forward costs” of a new entrant in the SEM, as these cannot be recovered in the energy market due to the BCoP.

¹¹¹ **Great Britain CPM Impact Assessment** (2013), page 58.

Figure B.3
The Supply Curve of Capacity Reflects the Cost of Existing and New Plant



The practical viability of either of these strategies is constrained by both the rules placed on market participants, and the elasticity of the demand curve used to procure capacity. Rules that prevent setting price above marginal cost, and an elastic demand curve, are both likely to mitigate the risk posed by predatory pricing.

B.4. Compatibility with EU Target Model

This section discusses the compatibility of the current CRM used in the SEM with the EU Target Model, and answers the following question put to us by Viridian:

- *From an economic perspective, what changes would need to be made to the current CRM in the SEM to make it compatible with market-coupling under the EU Target model?*

The EU Target Model is a set of proposals for the design of the electricity markets in Member States, where the responsibility for any necessary redesign rests with the relevant Member States. The EU Target model itself provides a high-level outline or framework, setting out five pillars that describe how Member States' electricity markets should operate. The five pillars are:

- Capacity calculation and zones delimitation;
- Cross-border forward hedging and harmonisation of allocation rules;
- Day-ahead market coupling;
- Intraday continuous trading; and

- Cross-border balancing.¹¹²

The EU Target Model neither permits (nor forbids) the introduction of a CRM. However, capacity market designs may cause conflicts with the implementation of the individual pillars. In particular, day-ahead market coupling requires the National Electricity Market Operators (NEMOs) to conduct “implicit auctions”, bundling capacity and generation between neighbouring electricity systems to allocate interconnector capacity efficiently.

The current CRM in the SEM varies every half hour, increasing in times of scarce supply (when the value of capacity is greatest), as described in Section 2.1.1 above. The payment has three elements (30% fixed, 40% variable *ex ante* and 30% variable *ex post*), one of which is not known until *after* the time of delivery and which varies with the loss of load probability that pertained in that hour. The RAs have stated that the current CRM in the SEM is not compatible with the day-ahead market coupling component of the EU target model:

“[The CRM] allows for capacity remuneration for all cross border flows (including capacity charges for exports) payable on a €/MWh basis. However these current arrangements would not work unaltered under the market coupling proposed as part of the EU Target Model, because the capacity price is not finally fixed until after real-time.

“To include the capacity price in market coupling would require the capacity prices to be known *ex ante* (for cross-border trading) which is not consistent with the calculation of an *ex-ante* pot that is rigidly adhered to”.¹¹³

Energy traders seek to hedge the risks of movements in prices and costs when selling electricity, by agreeing a firm price for future electricity sales at the same time as agreeing the costs of that sale. In the simplest case, this is done by entering a contract to *sell* some volume of electricity at a later date at the same time as entering a contract to *buy* enough fuel to produce the volume at that date. The trader therefore removes the risk of a movement in prices or costs from its portfolio.¹¹⁴ In the current SEM, one element of the energy price (the *ex post* capacity payment) is not known until after delivery has been made. While traders can base their sales on the expected level of this payment, it is a risk to the level of revenue they will receive that is still outstanding after a trade is made. Moreover, this risk cannot be hedged. This feature is a barrier to trading across borders.

The RAs use the alleged incompatibility of the existing CRM with the day-ahead market coupling pillar of the Target Model as an excuse for a complete review of the CRM design. However, in practice, it need not be necessary to fundamentally redesign the CRM in order to make the mechanism compliant with the target model. One obvious minor change to the

¹¹² ACER, *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* covers the Capacity Calculation and zones delimitation, Cross Border Forward Hedging and Harmonisation of allocation rules, Day Ahead Market Coupling and Intraday Continuous Trading pillars. ACER, *Framework Guidelines on Electricity Balancing* covers the Cross Border Balancing pillar.

¹¹³ **I-SEM – High Level Design** (2014), page 97, paragraph 10.2.4.

¹¹⁴ There are, of course, many more sophisticated hedging strategies – we consider the simplest example.

existing CRM that would make it compatible with the need to have clear price discovery day-ahead would be to remove the variable *ex post* element of the capacity payment and replace it with a fixed estimate of the *ex post* element *ex ante*. It is unlikely that this change will have significant effects on the incentives faced by the parties in the SEM to make generation available at peak, because the *ex post* payment is only known after the half-hour has occurred.

An alternative approach to fixing the payments to interconnected generation *ex ante* is to prevent external generators from receiving the capacity payment. The British government explicitly states that the definition of eligible generators in the GB capacity market needs to be compatible with the Target Model.¹¹⁵ Nonetheless, DECC currently plans to exclude foreign generators from the British capacity market.¹¹⁶

As a result, the need to comply with the EU Target Model need not require significant changes to the CRM in the SEM. Instead, complying with the EU Target Model may require adopting relatively minor tweaks to the design such as altering the *ex post* component of the current CRM or adapting the rules to exclude foreign generators.

¹¹⁵ **EMR Consultation** (2013), *Electricity Market Reform: Consultation on Proposals for Implementation*, DECC, October 2013, page 158.

¹¹⁶ **EMR Consultation** (2013), page 153.

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