



**Integrated Single Electricity Market (I-SEM)
High Level Design for Ireland and Northern Ireland
from 2016**

Consultation Paper SEM-14-008

A Submission by EirGrid plc.

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1 EXECUTIVE SUMMARY

The new I-SEM arrangements represent the biggest change to our energy market since the inception of SEM and will facilitate closer integration with markets across Europe.

The new arrangements must be both Target Model compliant and designed to meet the needs of the island of Ireland given the size of our market, the market share of different participants, the significant proportion of priority dispatch generation and the scale of variable, intermittent and non synchronous generation, both current and expected.

Bearing this in mind EirGrid has assessed the options consulted on against the SEM Committee's criteria as set out in the consultation paper.

EirGrid's analysis indicates options (3) (Mandatory Centralised Market) and (4) (Gross Pool - Net Settlement Market) provide stable markets with good transparency which will lead to better competition.

Given its strong liquid day-ahead market and the settlement of imbalances through a balancing market that reflects the actual cost of operating the system, of the two, option (3) has the potential to deliver more competition in the marketplace as well as more efficient cross border power flows and therefore offers the best longer term benefits for consumers in Ireland and Northern Ireland. There are a number of factors, for example balancing responsibility obligations for wind generators, which would however need to be carefully considered.

Conversely, EirGrid's analysis indicates options (1) (Adapted Decentralised Market) and (2) (Mandatory Ex-Post Pool For Net Volumes) have significant drawbacks as both designs are heavily dependent on external interventions. Both have the potential for liquidity to pool in non-transparent, out of market, bilateral arrangements which may not suitably promote competition either for independent market players or consumers.

Regardless of the option chosen system security is paramount. It is EirGrid's view that this can be attained in each of the energy trading options. It will however require the TSOs to have the necessary tools to enable timely redispatch of plant to maintain system security, which will inevitably impact on some of the perceived benefits of any self-nomination market. The design of certain elements within each option, such as the regulation of bidding and balancing obligations, may be more important to the management of system security and constraints than the choice of option itself.

In addition to a well functioning integrated energy market, complementary long term arrangements in respect of both capacity and system services that promote the right kind of investment are necessary.

System services will be important to safeguard power system stability and control in the presence of increasingly significant levels of wind generation. The upcoming SEM Committee decision on system services is important in this regard.

In a market with increasing zero marginal cost energy a capacity mechanism is also appropriate in providing revenue adequacy and therefore long term capacity needs. Of the options presented we favour volume based methods as they enable the remuneration of a

specific, and appropriate, level of capacity. In line with our preference for transparent centralised energy trading arrangements, our preference would be for a transparent centralised capacity remuneration mechanism. Ultimately system services and capacity together must provide for the additional revenue requirement above that provided through the energy market.

EirGrid reaffirms its commitment to working with both the industry and the Regulatory Authorities to deliver the new market arrangements by end 2016.

2 INTRODUCTION

2.1 EIRGRID PLC

EirGrid plc is a leading Irish energy business, dedicated to the provision of transmission and market services for the benefit of electricity consumers. We are committed to delivering high quality services to all customers, including generators, suppliers and consumers across the high voltage electricity system and via the efficient operation of the wholesale power market. We put in place the grid infrastructure needed to support competition in energy, to promote economic growth, to facilitate more renewable energy and to provide essential services. Both EirGrid, and its subsidiary SONI, have been certified by the European Commission as independent TSOs.

EirGrid holds licences as independent electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale trading system in Ireland, and is the owner of the System Operator Northern Ireland (SONI Ltd), the licensed TSO and market operator in Northern Ireland. The Single Electricity Market Operator (SEMO) is part of the EirGrid Group, and operates the Single Electricity Market (SEM) on the island of Ireland.

As part of its role EirGrid has developed and is operating a High Voltage Direct Current (HVDC) electricity interconnector with 500 MW transmission capacity linking the British and Irish Electricity markets. This is known as the East West Interconnector (EWIC). EirGrid Interconnector Limited is the licensed operator of EWIC and is a 100% wholly owned subsidiary company of EirGrid plc.

EirGrid welcomes the opportunity to comment on the Regulatory Authorities' Consultation Paper on the High Level Design of the Integrated Single Electricity Market (I-SEM). This response is submitted on behalf of all of the EirGrid licensees.

2.2 APPROACH TO ASSESSING THE ENERGY AND CAPACITY OPTIONS

As the TSO and MO for Ireland and Northern Ireland, EirGrid has a unique insight and understanding of the implications of each of the proposed options on the operation of the trading arrangements on the island, including the actual dispatching of generation to meet demand. We are independent of generation and supply businesses. We believe this independent expertise adds value to our response to this consultation.

We have considered the energy trading arrangements as proposed against the criteria agreed by the SEM Committee and set out in the Consultation Paper. In this light, we have considered each of the options firstly, in relation to how we believe they would impact on our ability to meet our operational objectives as system operator and market operator in Ireland and Northern Ireland and secondly, from a broader view of how effective we believe the arrangements will be.

In addition, we discuss our views on whether in principle a Capacity Remuneration Mechanism (CRM) should form part of the I-SEM and provide our views on the CRM options proposed.

2.3 STRUCTURE OF OUR RESPONSE

In this response, we have followed the layout of the Consultation Paper. We start by covering some contextual issues and explaining the assumptions that we have made ([Section 3](#)). This is followed by a discussion on some policy issues that are common across all of the energy trading options presented in the Consultation Paper.

[Section 4](#) provides a summary of our analysis of the energy trading and CRM options proposed for the I-SEM.

We then ([Section 5](#)) discuss each of the energy market options in turn against each of the assessment criteria set out in the Consultation Paper and provide our overall conclusion on the options.

This is followed in [Section 6](#) with our assessment of whether a CRM is a necessary requirement for I-SEM, our analysis of each of the CRM options proposed and our overall conclusion on these options.

There are two appendices. The first ([Appendix A – Importance of DS3](#)) briefly discusses the DS3 and how it interacts with the new market design process. The second ([Appendix B – Responses to the consultation questions](#)) contains our answers to the questions set out in the Consultation Paper.

3 CONTEXTUAL INFORMATION, ASSUMPTIONS AND COMMON ISSUES

3.1 DRAFT NETWORK CODES

Throughout this response, there are a number of references to the various European Network Codes that will form the legally binding rules for the internal market in electricity. These Network Codes, namely the Network Code on Forward Capacity Allocation (NC FCA), the Network Code on Capacity Allocation and Congestion Management (NC CACM) and the Network Code on Electricity Balancing (NC EB), have not yet entered into force and may be subject to further revision. EirGrid has produced an overview of these Network Codes which can be found on its website¹

As members of ENTSO-E, we have been instrumental in the development of these Network Codes and we continue to monitor their progression through the EU approval process.

While their content is not expected to change significantly, our comments with respect to these Network Codes are in the context of their current draft status.

3.2 LIQUIDITY

3.2.1 IMPORTANCE OF A LIQUID DAY-AHEAD MARKET

With any trading arrangements, it is important to have efficient price discovery. By this we mean that any party that wishes to buy or sell electricity should be able to base their trading on a clear understanding of the value of that electricity at that point in time. For this to occur, a liquid market is required, i.e. a market where a large amount of volume is traded on a regular basis. Liquidity is required to ensure price resilience and confidence that the price of electricity reflects its real value at that point in time. A liquid market is the cornerstone of competitive trading. As the volume of trade is high on a liquid market, the ability of portfolio players to influence the price in their favour is mitigated (assuming that market concentration levels are below certain levels). A stable and consistent price therefore promotes confidence in buyers that they are not over-paying and in sellers that there is a clear route to market. Under the Target Model, and currently across Europe, this liquidity is concentrated at the day-ahead stage when participants have a reasonable level of certainty about the availability of their generator units, the level of demand of their customers, etc. with sufficient time to introduce any changes that may be necessary as a result of the day-ahead market outcomes.

A liquid spot market is also important in that it provides the basis for forward trading. The emergence of liquidity in the forward timeframe is essential for risk management – among buyers who wish to provide fixed price contracts to their consumers and for sellers who need to hedge the value of their generation for asset management purposes. Forward contracts, be they financial or physical, are either based on a forecast forward price or explicitly include the spot price as a reference, as would be the case with derivatives. The ex-post price in the SEM provides this reference price currently; however, with the increasing importance of cross border trading and price coupling under the Target Model, in

¹http://www.eirgrid.com/media/ElectricityBalancing_16_12_2013.pdf

addition to the prevalence of the day-ahead timeframe as the European standard for the reference price, it is likely that a significant amount of trading will take place at the day-ahead stage. An important consideration here is not to split the liquidity between market timeframes to such an extent that none of them have sufficient liquidity to be a reliable reference price.

3.2.2 DELIVERY OF LIQUIDITY IN THE I-SEM

Liquidity in the spot market can be achieved through a number of possible approaches – natural, incentivised and mandated. Natural liquidity emerges on the basis of market need, where buyers and sellers both see value in trading a particular product at a particular point in time through a particular channel. This approach can work but tends to suffer from a lack of coordination. The second approach sees liquidity emerge on a voluntary basis but where one side of the market is incentivised to offer their volume in the market. One variant of this is the market maker approach, where a portfolio player is incentivised to offer all their volume into the market. This essentially kick starts the process with other traders then attracted to the existence of volume. Finally, mandatory approaches require that participants trade some or all of their volume through a particular market, e.g. in Ireland and Northern Ireland all physical trade by generator units >10MW must take place in the SEM.

There are pros and cons to the three approaches and most markets in Europe are somewhere on the spectrum between free emergence of liquidity and mandatory participation. GB and CWE markets allow for unlimited OTC (Over-The-Counter) bilateral trading; however, in recent years the liquidity on their day-ahead exchanges has increased steadily. In Nordpool, liquidity at the day-ahead stage is promoted by the scheduling of cross zonal trade in this timeframe. As there is a limit to how much can be traded within a zone, this effectively forces volume onto the day-ahead market. Another approach, in the Iberian market uses capacity payments to promote volume in the day-ahead market. These approaches provide options for promoting liquidity beyond the mandatory approach currently used in the SEM; however, it is imperative that a clear reference price exists and therefore, a mandatory or a quasi mandatory approach as in Nordpool or MIBEL may be appropriate.

3.3 SCHEDULING AND DISPATCH IN THE I-SEM

3.3.1 DISPATCH ARRANGEMENTS & THE IMPORTANCE OF BALANCING SERVICES

For the I-SEM, dispatch instructions must be managed centrally. The submission of unit nominations by participants does not mean that participants can self dispatch. All changes to generation must follow the issue of an instruction from the relevant TSO.

The TSOs are required to ensure security of supply and will achieve this through having the correct tools to redispatch when required. Operating and balancing the system 1 hour-ahead of gate closure represents a significant change to today's approach to system operation in Ireland and Northern Ireland. In order to be able to operate and balance the system efficiently, it is essential that the TSOs are provided with information in a timely fashion in terms of physically feasible nominations (e.g. reflecting ramp rates) and also that

generation and demand side resources provide offer prices and volumes for balancing services. The extent of these obligations and any associated rules or codes are, in the TSOs' opinion, at least as important as the individual energy trading option.

3.3.2 TSO OPERABILITY

There may be a desire to move toward market arrangements which give more freedom to participants to have more control over their positions and other aspects of their business. This desire is understood and there are clearly potential benefits in doing so. However this must be tempered with the fact that the market on the island is still a relatively small, isolated, constrained system, and is likely to continue to be for many years to come.

This does not mean that we should not move in the direction of more self-scheduling. We believe that system security can be maintained in each of the High Level Design options set out by the Regulatory Authorities (RAs). However, it is important that the mechanisms needed to deliver system security, their implications, the level of intervention which may be required by the TSOs in order to operate a safe, secure power system, and any associated consequences to participants, are clearly understood. The benefits that may be envisaged by some as arising from a more "self-dispatch" market, which is in fact more akin to one of "self-nomination", will inevitably be tempered at best by the factors set out above.

In our view the design of certain elements within each option may be more important to management of system security and constraints than the choice of the option itself. This includes:

- To what extent bidding is regulated (or subject to a code of practice) in any market timeframe;
- To what extent there is an obligation to offer in any timeframe, including an obligation to offer to the TSOs for balancing services and for constraint management; and
- The management of constraints where there are limited participants who can solve or in cases where only one participant exists, i.e. a monopoly.

3.3.3 IMPORTANCE OF DS3

The DS3 programme and the associated changes to the methods of rewarding the provision of essential system services are necessary to ensure that system stability and security can be maintained while accommodating an unprecedented proportion of non-synchronous generation on the transmission system. This programme is related to the technical characteristics of the generation portfolio on the island, and will continue to be vital to ensuring that customers' expectations of a safe, secure and reliable system are met, consistent with EirGrid's statutory obligations.

In our view, the system services required to ensure the reliable transmission of the energy are required irrespective of the energy option chosen and any capacity mechanism should complement both the energy and system services arrangements.

3.4 OTHER COMMERCIAL ASPECTS OF THE I-SEM

3.4.1 TRADING BOUNDARY AND TREATMENT OF LOSSES

Currently transmission losses in the SEM are calculated on a locational basis, with generators reflecting these in their bids. In other European markets TSOs purchase the energy to cover the losses incurred on their systems. The method of accounting for losses between the generation station and the trading boundary will impact on the commercial position of generation, particularly when competing for access to other markets via market coupling mechanisms.

The Consultation Paper is silent on both the trading boundary to be adopted for the I-SEM and the treatment of losses under the new arrangements. For the purpose of our response to this consultation we assume that the treatment would be the same across all options.

We would welcome clarification around both of these issues in the RA's draft decision.

3.4.2 TREATMENT OF PHYSICAL TRANSMISSION ACCESS

The Consultation Paper does not specify how the rights of non-firm generation may vary between the options, or how generation with non-firm access will bid into the day-ahead and intraday markets. The current model of the SEM is based on ex-post arrangements. This means that the level at which a generator with non-firm access is available to the market is based on real time activity. With the move towards markets with activity ahead of real time in the I-SEM, how non-firm generators are available to the market needs to be determined.

Until the substantial number of essential network construction projects are completed, there is expected to be an increasing amount of generation connecting to the system without firm access.

3.4.3 NEIGHBOURING MARKETS

An important consideration in the High Level Design process is the developments taking place in neighbouring markets. These include: the UK EMR process, the GB cash out review, the implementation of the NWE day-ahead coupling and the review of capacity arrangements across European states. These are all areas that may have a material impact on the effectiveness of the I-SEM arrangements and in our view should be given due consideration.

3.4.4 BALANCING COSTS

In order to assess equity in the consumption of electricity, consideration should be given to:

- How end-users manage cost risk in a manner that best suits their requirements; and
- How the costs associated with balancing priority dispatch plant that does not participate in any of the ex-ante markets are allocated.

These two issues are both related to the high proportion of priority dispatch plant that will be operating in the I-SEM by 2020. A significant number of end users (and suppliers) prefer to have a fixed price for electricity. Under two of the four options which do not include balancing markets, it appears that priority dispatch plant will be unlikely to be incentivised to participate in the ex-ante markets, meaning that suppliers (without a large and diverse

generation portfolio behind them) who wish to sell a low-risk product to customers may have to charge a significant premium to reflect the risk that they may have to absorb.

Given that the infrastructure to allow domestic customers to respond to time of use tariffs (e.g. smart meters) will not be in place before the new market commences, there is a risk of inequity between those parties who are able to respond to the intraday/balancing market signals and those who are not. This inequity will be most pronounced in the options with unit bidding in the ex-ante markets, which result in imbalances that will need to be addressed in real time. This could result in costs in the balancing market being excessively high at times of high wind due to the need to constrain down relatively expensive conventional generation that has already secured a buyer. To preserve equity, the TSOs or MO will need to separate out energy and non-energy balancing costs and allocate them according to the party that triggers the costs. The Consultation Paper is silent on how the RAs intend to approach this allocation.

3.4.5 INTERCONNECTORS

Currently all HVDC interconnectors in France-UK-Ireland-Netherlands region (FUIN) use Physical Transmission Rights (PTRs), which customers are familiar with. Work is ongoing towards harmonisation between EWIC, BritNed, IFA and Moyle. Currently, it is the norm across Europe to use PTRs rather than Financial Transmission Rights (FTRs), and as such we would caution against moving in a different direction without extensive analysis and evidence to demonstrate that a greater social welfare would result. It should be noted that there is also a harmonisation of allocation rules exercise underway throughout Europe where the focus is again on PTRs.

In SEM EWIC currently uses PTRs for all capacity and then applies UIOSI (Use It Or Sell It) to any capacity nominated which is out of merit in the bidding stack. In theory, therefore, the full volumes that are in merit/successful after the day-ahead price coupling are aligned with the prices that would be achieved if FTRs were used. Here, where nominations must be followed up with an in-merit bid to be successful, the result is effectively 100% liquidity in the day-ahead. If customers do not nominate or are not in merit then EWIC sells on their behalf in the day-ahead market. The current products on offer are reflective of customers' requested volumes over the various timeframes of annual / seasonal / quarterly / monthly and daily.

For the capacity payments, the key principle is to make any payments for capacity directly to the capacity provider (interconnector owner/operator) rather than the capacity holder (interconnector user). This maximises social welfare by allowing customers to bid without the influence of capacity payments being affected by the potential physical unavailability of the interconnector. It also ensures the appropriate incentives are available for the building of further interconnectors to the extent that they contribute to adequacy.

4 SUMMARY OF EIRGRID'S ANALYSIS

4.1 ENERGY TRADING ARRANGEMENTS - ANALYSIS SUMMARY

EirGrid is of the view that, with the correct tools, it can operate any of the design options from the view of both a power system and a market.

As such, this response is primarily concerned with how effective we believe each of the options will be, from our experience as system operator and market operator. Some of the assessment criteria are considered neutral across all options, for example, given the level of detail available at this stage, it is difficult to clearly differentiate between the four options in terms of practicality and cost. However, it is possible to determine differences in the HLD options in terms of competition, efficiency, equity, the Internal Energy Market and stability.

While we would differ with some details with regard to the opinions expressed in the Consultation Paper, we find that our final assessment broadly aligns with that of the RAs.

4.1.1 OPTION (1) – ADAPTED DECENTRALISED MARKET

Security of Supply: This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. By this we mean the ability to issue firm instructions to participants across intraday through to forward timescales that reflect their technical and commercial submissions.

Stability: This is a robust market design based on the existing NWE markets. The Consultation Paper lacks clarity on how liquidity in the day-ahead market will be achieved. Each of the adaptations proposed represents regulatory intervention in the market and as such recognises that the market design, on its own, is not stable enough to deliver on the objective.

Efficiency: Under this option the TSOs consider that redispatch volumes are likely to be higher than is currently the case due to the current SEM complex bids allowing for complete optimisation. Additionally, it is uncertain whether all participants will deliver feasible unit nominations to the TSOs.

Practicality/Cost: It is difficult to point to a single option that would clearly stand out as being more cost effective to implement and maintain over the medium term.

Equity: Mandatory participation of intermittent generation in the day-ahead market would be expected to limit the cost of balancing priority dispatch plant. Given this option strongly favours vertically integrated electricity companies there is a risk that this option could result in an oligopoly, which would result in an inequitable sharing of the costs and risks.

Competition: This option favours parties with larger portfolios of generation and supply customers. Small independent players would be largely forced to find bilateral partners or be left trading in the day-ahead and intraday markets. Aggregators are however a possible alternative route to market for smaller-scale, dispersed generation. A lack of transparency could hamper new entry and hinder retail competition.

Environmental: Balancing markets are generally viewed as less favourable for generation whose output is more difficult to forecast i.e. renewables. The option should encourage

participants who own renewable generation to improve their forecasting ability and trade in advance of gate closure, which is advantageous.

Adaptive: While no option stands out as being better or worse under this criterion, models with greater integration of the European day-ahead and intraday markets will be subject to the governance arrangements that apply in Europe.

The Internal Energy Market: While broadly following the Target Model, this design would likely require additional work to integrate with the NC EB which moves towards a position of shared balancing services across a Coordinated Balancing Area.

Without clarity on liquidity attracting measures option (1) could develop into a bilateral trading based market. Therefore, in our view, transparency, entry and ultimately competition may be adversely affected. Conversely, if a liquid day-ahead market can be delivered under this option, making it a more centralised set of arrangements, transparency and equity would be improved. The application of balance responsibility places additional participation requirements on small generators, including renewables, which must find market positions rather than be exposed to balancing prices. There are measures, such as market aggregator functions, that have the potential to address this and these could be explored during the detailed design phase.

4.1.2 OPTION (2) – MANDATORY EX-POST POOL FOR NET VOLUMES

Security of Supply: This option allows the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. By this we mean the ability to issue firm instructions to participants across intraday through to forward timescales that reflect their technical and commercial submissions.

Stability: While elements included have been implemented separately elsewhere, there is no working model of this market in the world. Therefore, it is not possible to assess how robust this market design actually is. The Consultation Paper indicates that this option may require significant regulatory intervention in order to attract liquidity to the desired market.

Efficiency: To model how this option would work in practice is particularly difficult and hence the efficiency of this option is less certain than for the others.

Practicality/Cost: It is difficult to point to a single option that would clearly stand out as being more cost effective to implement and maintain over the medium term.

Equity: Under this option equity will depend on the viability of the regulated limit that would be applied in the ex-ante markets. A lack of detail on how this would be enforced means that it is not possible to endorse this as an equitable allocation of production costs. While a regulated limit of this sort would mitigate against the risk of an oligopoly developing, it has the potential to disadvantage portfolio players.

Competition: Without detail on market power mitigation measures, it is difficult to assess if this option can deliver on this criterion. Strict control of behaviour would be needed to ensure this market does not become a set of out of market bilateral arrangements for dominant players with an illiquid ex-post pool for wind and small players.

Environmental: The difficulty in knowing where the volumes of market activity will fall across the market timeframes means there is insufficient detail at this point to meaningfully comment on this criterion.

Adaptive: While no option stands out as being better or worse under this criterion, models with greater integration of the European day-ahead and intraday markets will be subject to the governance arrangements that apply in Europe.

The Internal Energy Market: Full alignment with the NCEB is not clear and it is likely that a market designed with an ex-post pool element will require further re-design.

Option (2) has significant drawbacks given its complexity and lack of clarity on how and where liquidity will be concentrated. We understand that this market has not been implemented anywhere in the world before, which also raises stability concerns. Adaptations that could be proposed to this model to deliver a more stable design would result in a market that closely resembles one of the remaining three options.

4.1.3 OPTION (3) – MANDATORY CENTRALISED MARKET

Security of Supply: This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. By this we mean the ability to issue firm instructions to participants across intraday through to forward timescales that reflect their technical and commercial submissions.

Stability: This design should be a stable market subject to EU governance. There is little in the way of regulatory intervention noted in this design. This further contributes to this option's stability.

Efficiency: Under this option, the majority of redispatch by the TSOs is likely to occur across intraday timescales once the day-ahead market completes. It is expected that at gate closure all participants would have a balanced position. The TSOs consider that redispatch volumes are likely to be higher than currently experienced under SEM.

Practicality/Cost: It is difficult to point to a single option that would clearly stand out as being more cost effective to implement and maintain over the medium term.

Equity: Mandatory participation of intermittent generation in the day-ahead market will provide a more equitable distribution of risk, limiting the cost of balancing priority dispatch generation.

Competition: This option provides a strong liquid day-ahead market with transparent trading and pricing. This market is also based on simpler rules and participation than the ex-post pool options which should prove attractive to new entrants.

Environmental: Balancing markets are generally viewed as less favourable for generation whose output is more difficult to forecast i.e. renewables. The mandatory nature of the day-ahead market might also prove a challenge for renewables. The option should encourage participants who own renewable generation to improve their forecasting ability and trade in advance of gate closure which is advantageous.

Adaptive: While no option stands out as being better or worse under this criterion, models

with greater integration of the European day-ahead and intraday markets will be subject to the governance arrangements that apply in Europe.

The Internal Energy Market: This option is very closely aligned with the Target Model and contains many of the characteristics of the existing European markets although further modification is likely to be required to incorporate the requirements of the NC EB.

Option (3) provides a stable market with good transparency that has the potential to encourage market entry given its strong liquid day-ahead market. In addition, settlement of imbalances through a balancing market that reflects the actual cost of operating the system places greater emphasis on the importance of being balanced as the market approaches real time. The design of the measures to enforce the mandatory nature of this market remains an open question and this is a key concern as this is a fundamental building block of this option. Further clarity and rules around the nomination process for results from the day-ahead market coupling process to the TSO may mitigate against concerns around the efficiency of dispatch arrangements. Smaller generators, including renewables, face additional requirements under this option as they must trade in the day-ahead and intraday markets in advance of balancing. Market aggregator functions could assist in this area and this should be explored during detailed design.

4.1.4 OPTION (4) – GROSS POOL/NET SETTLEMENT

Security of Supply: This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. By this we mean the ability to issue firm instructions to participants across intraday through to forward timescales that reflect their technical and commercial submissions.

Stability: While there are no working examples of this type of market in Europe, they have been implemented elsewhere. With EU prices setting the cross border flows independently of local market pricing, there is a risk of counterintuitive interconnector flows.

Efficiency: The Integrated Scheduling Process allows for a full system optimisation taking into account Interconnector nominations.

Practicality/Cost: It is difficult to point to a single option that would clearly stand out as being more cost effective to implement and maintain over the medium term.

Equity: The potential absence of priority dispatch plant in the day ahead and intraday markets impacts on the equitable sharing of costs.

Competition: The centralised design should promote effective competition by promoting a more transparent market place with clear pricing and an easier route to market for smaller players, though the complexity of the pool has the potential to act as a barrier to entry. While wind generators and retailers can avoid the risk that comes with more active participation at day-ahead market, they lose out on the opportunities to trade across borders into the European market.

Environmental: Under this market design, the volume of countertrading by the TSOs has the potential to grow as more renewable generation connects and the TSOs will need to minimise curtailment of renewables; however, it is possible that financial traders in the

intraday market may take advantage of any arbitrage opportunities which could counter this and deliver efficient interconnector flows.

Adaptive: While no option stands out as being better or worse under this criterion, models with greater integration of the European day-ahead and intraday markets will be subject to the governance arrangements that apply in Europe.

The Internal Energy Market: This option seeks to implement the Target Model through the use of financial trading at day-ahead and intraday. While offering a number of advantages, it is unclear whether this option delivers the full potential benefits to consumers in Ireland and Northern Ireland as the European prices may never be truly integrated. Full alignment with the NC EB is not clear and this option may require further re-design in this area.

Option (4) delivers on transparency and other competition requirements. An ex-post market provides for a more benign imbalance settlement, reducing participants' risk in relation to imbalances; however, this could mean that current countertrading arrangements relating to wind generation continue. A potential drawback on this option is how the European price is integrated into the I-SEM and how consumers will see the overall benefit of this. Setting cross border flows in a separate mechanism from the market pricing may result in counterintuitive cross border power flows.

4.2 CAPACITY REMUNERATION MECHANISM (CRM) – ANALYSIS SUMMARY

As a result of inelastic demand, large discrete ('lumpy') investments and market power, revenue adequacy is likely to be an issue in the I-SEM in the absence of other long term remuneration mechanisms. In this regard, we believe that a capacity mechanism should be retained but redesigned in the context of the overall review of energy and system services to:

- **Ensure overall value for money for consumers.** A consistent approach across all revenue streams is imperative in this regard, e.g. the SEM capacity mechanism reflects the requirement to submit cost reflective offers to the energy market and includes a provision for ancillary services revenue. Energy, system services and capacity revenue should reflect their overall value.
- **Promote good behaviour, drive efficiency and promote innovation.** Any well designed capacity mechanism should reduce investment risk, while retaining a sufficient amount of commercial risk to ensure reliable and efficient performance. Where this is no longer possible, the mechanism should provide the appropriate signal to exit the market.
- **Promote more efficient cross-border trade.** In the context of the Target Model, a well designed capacity mechanism should not distort the efficient cross-zonal flow of energy. Furthermore, to promote investment, cross-zonal capacity (i.e. interconnection) should be rewarded to the extent that it contributes to adequacy.

On balance, we believe that one of the four market-wide quantity-based approaches should be considered for the capacity mechanism. In line with our preference for transparent centralised energy trading arrangements, our preference would be for a transparent centralised CRM. In this regard, capacity auctions and centralised reliability options would appear to be the more suitable candidates; however, the choice of quantity-based mechanism in our view should be taken following a more detailed assessment against the chosen energy trading arrangements. Price based options are not recommended. Strategic reserves may have merit in some cases but not as long term arrangements.

EirGrid believes that an energy only market is not sufficient to provide the necessary long term signals to attract the appropriate level of investment to ensure security of supply and deliver on policy objectives. In our view, promoting investment in system services that enhance power system stability and control in the presence of increasingly significant levels of wind generation is essential. As a complement to energy and system services revenue, our view is that a market-wide quantity-based capacity mechanism is a pragmatic approach to assuring revenue adequacy and a reasonable degree of predictability for investors and delivering long term value for customers.

5 ENERGY TRADING ARRANGEMENTS

In this section we present our analysis of each of the options against each of the assessment criteria set out in the Consultation Paper and provide our overall conclusion on the options.

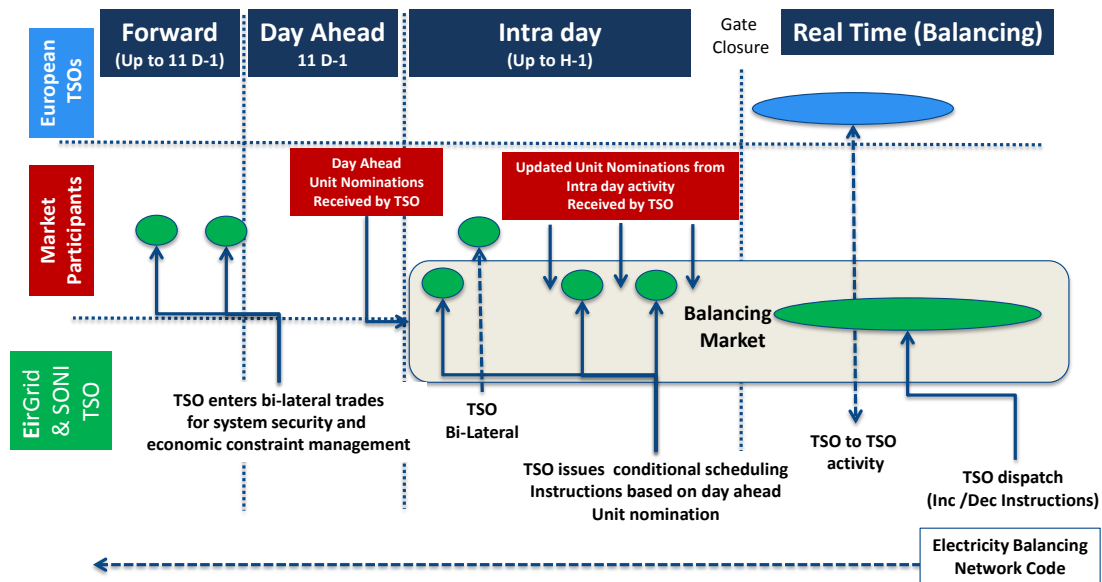
5.1 OPTION (1) – ADAPTED DECENTRALISED MARKET

This option is based on bilateral trading in the forwards timeframe followed by participation on the European day-ahead and intraday markets and concluding with a balancing market. While the balancing market has been described as using marginal pricing, the Consultation Paper is not clear on this and notes that dual price imbalance prices can be used.

The following sections outline our assessment of this option against the agreed criteria.

5.1.1 SECURITY OF SUPPLY

This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. The figure below highlights the periods where TSO activity may take place.



In the forwards timeframe, the TSOs envisage having the capability to enter into bilateral trades with participants for system security and constraint management similar to other regions where this market design exists. These bilateral trades entered into by the TSOs are only for a physical need with no speculative trading and are also restricted.

This option also requires participants to convert their portfolio nominations into unit specific nominations that respect the technical characteristics of the unit (e.g. ramp rates etc.) and do not have step changes in nominations which are not physically feasible and make frequency control difficult. As the TSOs are using this information to determine an initial feasible solution for system security, it is important that all participants submit the best information they have in a timely fashion. It is therefore anticipated that these unit nominations would arrive to the TSOs early in the afternoon to allow the TSOs time to carry

out detailed security studies. In the GB market, which looks similar to this option, there is an “Information Imbalance Charge”² to encourage accurate unit nominations and this should be considered as part of any detailed market design.

Across the intraday timeframe, the balancing market is voluntary and, as highlighted in the figure above, the TSOs could be carrying out some of its activity in the intraday market as well as within the balancing market. This appears unnecessarily complex and it would be preferable that all activity would be carried out within the balancing market which would then need to be mandatory.

When the balancing market opens, participants would be required to submit Inc & Dec prices along with technical data to allow the TSOs to determine the economic solution to deliver a feasible solution. This process would not be a complete optimisation but rather the minimum changes to the participants’ unit nominations. Throughout the intraday market, participants would continue to trade and update the TSOs with changes in nominations. Based on these changes, the TSOs would be checking system security and making changes accordingly, subject to agreed tools which are essential for the TSOs to manage redispatch across intraday timescales. In the balancing market, the TSOs may have difficulty in economically optimising a feasible solution if Inc & Dec prices changed materially close to gate closure. For example, the TSOs could be intending to run a specific generator in a location but are waiting as the generator is flexible and available on short notice. If that generator then increases prices before being dispatched, other more economic options which did not have the same flexibility may no longer be able to synchronise in time. Hence, in the detail design stage, the TSOs may need to agree rules on participants pricing behaviour when submitting prices in the balancing market. We would propose that this is applicable to all options with balancing markets.

After intraday gate-closure, the TSOs will ensure real-time balance by Inc & Dec instructions to local participants and also via TSO to TSO activity, subject to the requirements within the NC EB. This code standardises a cross border framework which forms the basis for the local areas’ terms and conditions. At some point in the future, Automatic Generator Control (AGC) may be required to automate the dispatch process for real-time balancing.

5.1.2 STABILITY

This design appears to be based on the existing NWE markets. The consultation equates this model to Nordpool; however, it is not fleshed out in sufficient detail to confirm that this will be the case in practice.

While this option is titled as a decentralised market, it is described as having adaptations that seem intended to result in liquidity pooling in the centralised day-ahead market, which would result in a market that resembles option (3), rather than a decentralised option, though still based on portfolio participation. As such, it is difficult to understand the objectives of this design. Each of these adaptations represents regulatory intervention in the market and as such recognises that the market design, on its own, is not adequate to

²<http://www.elexon.co.uk/reference/credit-pricing/trading-charges/>

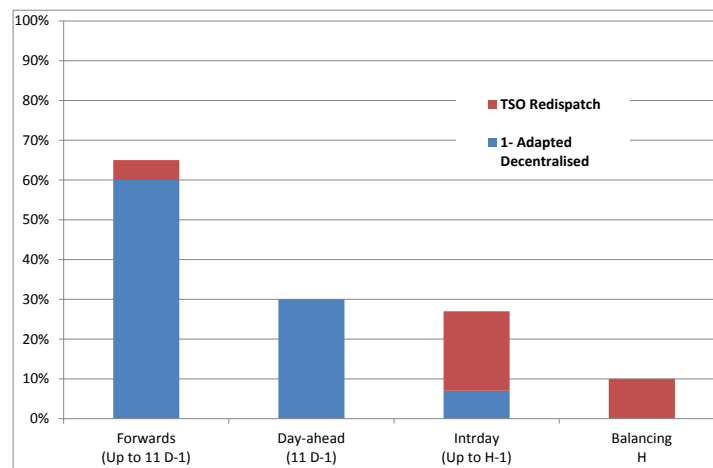
deliver on the objectives. The application of these interventions means that the principal market for trading in this option can range from being a set of bilateral based arrangements to a day-ahead centralised auction which would represent considerable uncertainty for the industry.

The consultation does not contain the detail required to demonstrate that this market will achieve the intention of delivering a liquid day-ahead market. As such when it comes to the statement in paragraph 6.4.3 of the Consultation Paper that this option has "the potential to score strongly across a number of criteria if the adaptations to promote liquidity in the DAM and IDM are effective", the opposite could also be true in that this option has the potential to score badly across a number of criteria if the adaptations to promote liquidity in the DAM and IDM are ineffective.

5.1.3 EFFICIENCY

The volume of redispatch required by the TSOs due to transmission system constraints and reserve requirements, which is common to any future design, is difficult to quantify at this stage. The volume of the required redispatch is difficult to quantify at this stage.

A qualitative assessment is shown below based on assumptions of where participants could trade (shown in blue). This is highly subjective and could change significantly depending on what rules are in place.



The TSOs consider that redispatch volumes are likely to be higher than is currently the case under SEM. This is due to the current SEM complex bids that allow for a complete optimisation, compared to where this is replaced by simpler bids in day-ahead and intraday as well as allowing self nomination from the bilateral trading arrangements. Additionally, it is uncertain whether all participants will deliver feasible unit nominations to the TSOs.

The efficiency of this model across the intraday timescales is driven by the voluntary nature of the balancing market, which may or may not attract participants to offer plant at the required timescales. It is then assumed that the TSOs would be able to enter into bilateral trades in the intraday which may be adverse to efficiency as the TSOs may be perceived by participants as a "stressed buyer". Therefore, the TSOs' view is that a proposed change to this option would be to make the balancing market mandatory across the intraday.

The costs of these redispatch actions in real-time will depend on the Inc & Dec prices submitted by participants and the changes in these prices up to real time balancing. The TSOs would anticipate that, as a minimum, all Inc & Dec prices (along with changes) would be fully transparent with rules on what is allowed e.g. price changes close to gate closure, price changes after being instructed etc.

Under this option, the TSOs' view is that at times, forward bilateral trades could be undertaken to get access to long notice plant, to efficiently manage constraints and avoid being a "stressed buyer" across intraday. Notwithstanding, the majority of the redispatch volume will be across intraday timescales due to the physical characteristics to get conventional generation scheduled, synchronised and up to full load. Within real-time balancing (1 hour window), the TSOs manage the system for frequency and constraint management and it is assumed that all participants are balanced.

5.1.4 PRACTICALITY/COST

It is assumed that the current implementation of the Central Market Systems will be decommissioned on an active basis at end 2016; however, these will be retained for a period of time to cover the M+13 resettlement period defined in the SEM. Consequently, a new suite of systems will be commissioned to deliver trading arrangements aligning with the Target Model.

Given the level of information provided in the Consultation Paper, it is difficult to point to a single option that would clearly stand out as being more cost effective to implement and maintain over the medium term. A number of principles will however have a direct bearing on the implementation and operational cost of the new systems. The extent that the system operator and market operator systems can be integrated is one consideration.

5.1.5 EQUITY

Equity is defined in the Consultation Paper as: "market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable way." The Consultation Paper does not provide information about how the SEM Committee intends to allocate the costs associated with transporting electricity; however it is possible to comment on the allocation of costs and risks associated with production and consumption.

The use of gross portfolio bidding allows generator portfolio players to reflect the probability of high levels of wind in each timeframe within their bids, which should result in prices in the ex-ante market more closely reflecting the expected marginal prices (assuming market power is adequately managed). However, this option strongly favours large vertically integrated electricity companies, limiting opportunities for smaller generators and independent suppliers. There is a risk that this option could result in an oligopoly, which would result in an inequitable sharing of the costs and risks.

5.1.6 COMPETITION

As written, this option is dependent on regulatory intervention to succeed. We have considered the design as put forward without these interventions described. As such, proposed advantages of this design could equally be disadvantages if the adaptations proposed at a later date prove ineffective.

The restriction to gross portfolio participation in the day-ahead and intraday markets only succeeds if there are limitations on the actions that a portfolio player can do in the bilateral market. Small independent players could be forced to find bilateral partners or be left trading in the day-ahead and intraday markets. The liquidity of these markets is dependent on the level of competition that already exists before the market starts. An independent generator can succeed as long as independent suppliers also exist and act in the day-ahead market. Relying on the cross border capacity to deliver liquidity is problematic where PTRs are available, as these may allow dominant players to physically congest any interconnectors in advance of the day-ahead market. This can be managed through applying limitations in the allocation process. However, whether there will be sufficient internal liquidity in the I-SEM to support a successful day-ahead market for independent players is an important consideration. The level of intervention proposed for this option could reduce certainty and stability and could discourage new entry.

Transparency of price is also a key driver of competition. It is unclear how this option delivers on this. While day-ahead, intraday and balancing prices can be transparent, if a significant volume is traded outside the public market places, the prices and costs of this are invisible to the industry and potential new players, which could hamper new entry and hinder retail competition.

The view expressed in the Consultation Paper that allowing portfolio participation will incentivise financial players is essentially true of all proposals and is not a particular advantage of this option. Financial players can act in unit based markets as supplier units which are essentially portfolios.

The adaptations to make a strong liquid day-ahead market are key to competition in this option. Without sight of these it is difficult to say with confidence whether this market will deliver on this objective. An efficient market design should encompass these and not require additional intervention in the market place to ensure its success.

5.1.7 ENVIRONMENTAL

Balancing markets are generally viewed as less favourable for generation whose output is more difficult to forecast, i.e. renewables. Participants who own and operate renewable generation are required to forecast the output expected in real-time and ensure that they are balanced prior to intraday gate closure. For any participants who are not in balance, the imbalance is settled subject to the methodology for imbalance price calculation. Experience of imbalance market price calculation indicates that diverging interests may emerge. For example, the TSOs may want the imbalance price to provide the right incentive for participants to balance prior to gate closure while participants may want a more benign imbalance price in order to minimise the financial consequence of being out of balance.

For a participant who solely owns renewable generation such as wind, aggregators can offer a route to market by achieving the benefits of having multiple wind generators at various locations and hence achieve the benefits of dispersion. We would propose that this type of aggregator should be considered for all market design options as it will provide flexibility to wind generation and will further facilitate the integration of renewables into the market and power system.

From the TSOs' perspective, this design should encourage participants who own renewable generation to improve their forecasting ability and trade in advance of gate closure. This will tend to support exporting interconnector flows at times of high renewable generation on the island.

5.1.8 ADAPTIVE

Currently no option stands out as being better or worse under this criterion as the adaptability of the design is very much dependent on the detailed design decisions in relation to governance. We assume that the "Governance arrangements" relate to the market modifications process which should support any evolving design and policy requirements, and should consist of a decision making committee along with a market consultation process.

While we accept that governance arrangements are normally developed during the implementation phase of a market project, we felt that some assessment of this criterion is appropriate. If we consider that the adaptive nature of a market is based on our ability to represent change, we then have to consider our ability to change the EU based markets. Both the day-ahead and intraday markets will be under the governance arrangements defined in the NC CACM, use of PTRs and FTRs will likely fall under the arrangements of the NC FCA and cross border balancing will come under NC EB. As such, the ability of parties in the I-SEM to influence change in these market places is based on representation on the TSO and Nominated Electricity Market Operator (NEMO) committees that manage how change is assessed, implemented and costs are shared. In this light, this also means we are subject to changes that can come from other countries.

5.1.9 THE INTERNAL ELECTRICITY MARKET

This option complies with the Target Model by delivering day-ahead and intraday market arrangements, coupled with physical bilateral trading in both the forwards and intraday timeframes and a marginal balancing market in the ex-post time.

Of issue is whether this represents an efficient implementation. One of the problems with this design is that its efficiency is a product of where the liquidity concentrates. A liquid day-ahead market would promote efficient cross border trade based on price; however, liquidity attracting measures are not set out.

As a result, this design is largely the BETTA market: fully aligned with the Target Model in terms of day-ahead and intraday but with the potential for liquidity to settle into out of market bilateral contracts. While BETTA is moving towards a more liquid day-ahead market through policy innovations, other NWE markets with similar elements (the French, German,

other central European markets) are still based on larger volumes of trade concentrating in outside of market arrangements. As a result, this implementation has the potential to have limited integration of the day-ahead and intraday European prices into the I-SEM. As a result, the efficiency of this option in terms of implementing the Target Model and efficient cross border trade is not clear.

While this option includes a developed set of balancing arrangements, these are largely based on local balancing requirements. As such, whether these fully conform to the Target Model for balancing, which moves towards a position of shared balancing services across a Coordinated Balancing Area (COBA), needs to be carefully considered. While there is allowance for unsharing of bids which means that a System Operator can retain a set of local balancing arrangements, the NC EB foresees that there will be no unshared bids in its final implementation. As a result, this market option may require further amendments to ensure it meets the final Network Code requirements of the Target Model.

5.1.10 OPTION 1 CONCLUSION

Taken at face value, this design appears to mirror the BETTA arrangements closely. Issues with this design primarily relate to efficiency, competition and transparency. This type of market tends to suit portfolio players with both retail and generation business who can internalise costs independent of a transparent market place. It may also provide opportunities for portfolio players to manage credit risk and transaction costs across their portfolio. The provision for gross portfolio participation at day-ahead and intraday may not mitigate against this if portfolio players are allowed participate in bilateral contracts in an unrestricted manner.

The Consultation Paper describes this as similar to Nordpool, including frequent references to a strong liquid day-ahead market; however, we feel this may not be an appropriate comparison. In Nordpool, participation at day-ahead has become pseudo-mandatory. This was achieved initially by splitting the Norwegian market (before the other Nordic areas joined) into smaller zones, equivalent to bidding zones and mandating that trade between these zones could only happen in the day-ahead market. In the absence of greater detail of how this option will move towards a more centralised set of arrangements based around the day-ahead market and, given that it is described as a “decentralised” market, we have considered it in that light.

The use of market aggregators could be of benefit for small wind generators in a balance responsible market. We believe this market design option can be improved by mandating participation in the balancing market and the development of rules on participant pricing in this timeframe.

While we note that the Consultation Paper proposes that this design could score well if the proposed adaptations are effective, in the absence of detail on the proposed adaptations, it is difficult to make this statement with confidence. The proposed adaptations could prove ineffective resulting in a poor market design. Key to this is whether the market design itself should deal with issues of market power and liquidity or whether these should be part of the adaptations that arrive later in the process. An efficient market design should properly

address these items and not require additional intervention in the market place to ensure its success. As such, the “Adapted Decentralised Market” scores poorly in our assessment.

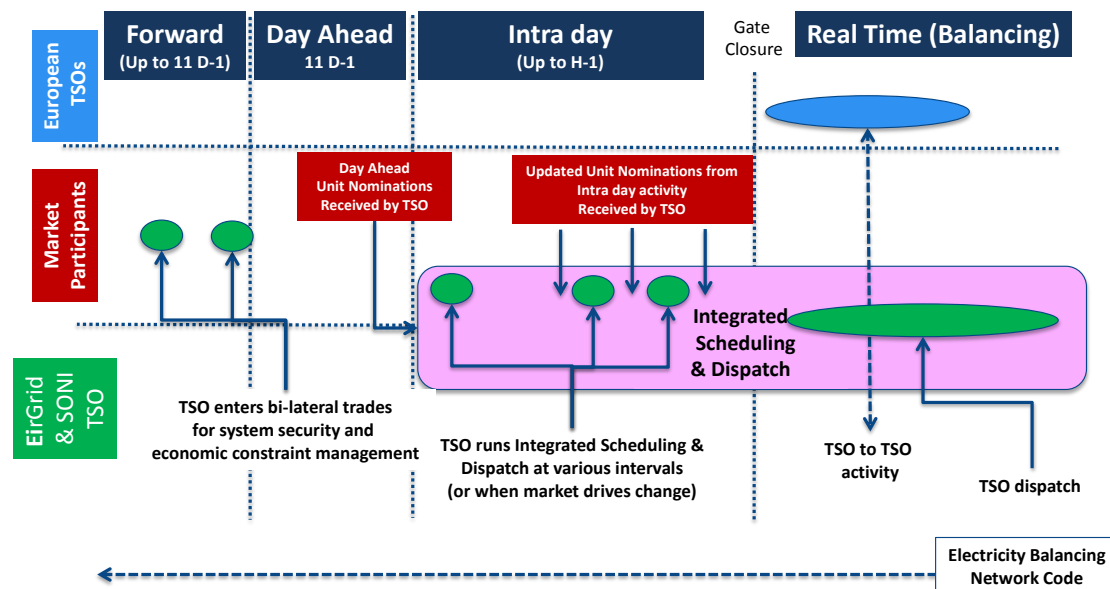
5.2 OPTION (2) – MANDATORY EX-POST POOL FOR NET VOLUMES

This option is a hybrid market based on bilateral trading in the forwards timeframe, followed by the European day-ahead and intraday markets and concluded with an ex-post pool. Pricing in the ex-post pool will be based on marginal pricing principles but is complicated by having to account for shifting generation both up and down.

The following sections outline our assessment of this option against the agreed criteria.

5.2.1 SECURITY OF SUPPLY

This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. The figure below highlights the periods where TSO activity may take place.



In the forward timeframe, the TSOs envisage having the capability to enter into bilateral trades with participants for system security and constraint management.

For this option it is unclear to the TSOs where participants would concentrate liquidity and hence after the day-ahead, the volume that is required to be covered with the first Integrated Scheduling Process run is uncertain.

This uncertainty of participants’ behaviour under this model design (unless limited by volume restrictions) makes it difficult for the TSOs to comment further.

5.2.2 STABILITY

This is a hybrid market design which has elements of an ex-post pool with ex-ante physical bilateral trades. While the elements included have been implemented separately elsewhere, there is no working model of this market in the world. As a result, it is not possible to assess how robust this design of market actually is. It shares a lot of similarities with option (1) in that it allows portfolio participation (net in this instance) and uses forwards physical bilateral contracts. In the ex-post timeframe, a net pool is adopted in place of balancing market arrangements. While this provides for some degree of comfort for small market players in that they can rely on the pool results rather than actively trade in the ex-ante markets, the success of the pool is heavily dependent on the liquidity that it attracts. If the larger volumes of trade move to the ex-ante markets, then the pool will just serve as a very complex set of balancing arrangements. As the liquidity moves around this option, it begins to look like one of the other three designs presented.

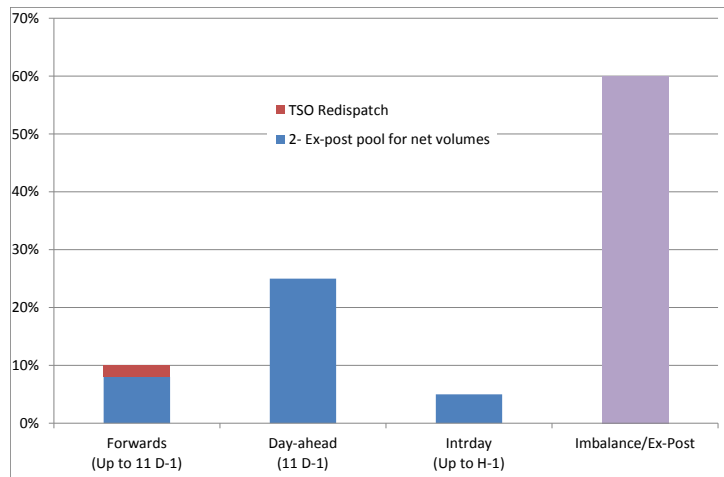
A problem with this is that this market is described in the Consultation Paper as being based on the Integrated Scheduling Process (paragraph 5.1.7 & 7.4.43). This is a European term for day-ahead central unit commitment. As a result, the dispatch arrangements coupled with this market only work where the ex-post pool has high liquidity. If the larger volumes of trade move to any of the ex-ante markets, there may be an inconsistency between the dispatch and market arrangements.

The Consultation Paper indicates that this option may require regulatory intervention in order to attract liquidity to the desired market (assumed to be the pool in this case). While recognising that these will be necessary to attract liquidity to the pool the fact that the market does not deliver this without intervention is a sign of poor stability.

This design would score low under this criterion due to the level of intervention required but also that it would be a brand new form of wholesale electricity market. This is also evident in the determination of the ex-post price which, according to the Consultation Paper, is expected to be difficult as it is based on marginal costs of increases and decreases.

5.2.3 EFFICIENCY

The volume of redispatch required by the TSOs due to transmission system constraints and reserve requirements, which is common to any future design, is difficult to quantify at this stage. The TSOs' view is that the efficiency of this option relies on the ex-post pool being the dominant market.



A qualitative assessment is shown above based on assumptions of where participants could trade (shown in blue) with the ex-post pool being dominant (purple). This is highly subjective and could be the complete opposite in reality due to the uncertainty of predicting where participant activity will concentrate. As highlighted in the figure above, if volumes traded in the forwards and day-ahead were of the order of under 50% of the demand, then the TSOs anticipate that Integrated Scheduling Process would add to the unit nominations with minimal changes. To model how this option would work in practice is particularly difficult and hence the efficiency of this option is less certain than for others.

5.2.4 PRACTICALITY/COST

The comments provided in respect to option (1) apply equally to this option.

5.2.5 EQUITY

Equity in this option will depend on the viability of the regulated limit that would be applied in the ex-ante markets. Without further information on how this would be enforced, and an assessment of how compatible this is with the Target Model, it is not possible to endorse this as an equitable allocation of production costs. While a regulated limit of this sort would mitigate against the risk of an oligopoly developing, it has the potential to disadvantage portfolio players. Priority dispatch units are not required to participate in the day-ahead and intraday markets and therefore, as there is expected to be a high proportion of priority dispatch plant in the I-SEM, the socialisation of balancing costs could distort the equity of this option.

5.2.6 COMPETITION

The pooling of liquidity in this option is key to whether it measures well against this criterion. This market design contains many of the pitfalls that appear in option (1) if the market tends towards being largely determined from bilateral trading. If the pool becomes the dominant trading market, then the option trends towards option (4) and the market may succeed in delivering a lot of the competitive measures that are in the SEM today.

Because there is no clarity with respect to where the liquidity will go in this option, while recognising the intention appears to be to attract it to the ex-post pool, we have considered how this market could operate for different players.

A large portfolio player would have the advantage of being able to participate as a net portfolio in this option. This will allow dominant market players to strike their positions outside of the public market, with no transparency of pricing, which could have a detrimental impact on the ability to attract new entrants. If liquidity pools outside the public market, new players would be dependent on their ability to find bilateral partners in advance or be reliant on what liquidity remains for the ex-post pool or day-ahead and intraday markets. Net portfolio bidding would also mean market monitoring is a more complex function than currently is the case.

Existing small independent generators, including wind and suppliers, may be forced into the ex-post pool and left in a market of last resort. Depending on the liquidity in this market, this would impact the prices available to them. If the ex-post pool is dominated by price taker wind generation, this would have a depressing affect on the price paid to generators and would likely detract future investment.

As a result, clear market power mitigation measures are essential building blocks of this design. As written, without these building blocks, it is difficult to assess if this option can deliver on this criterion. Strict control of behaviour would be needed to ensure this market does not become a set of out of market bilateral arrangements for portfolio players with an illiquid ex-post pool for wind and small players.

This could be addressed through market maker obligations forcing key players to trade through the ex-post pool; however, this would detract liquidity from the day-ahead which may be the preferable market place for liquidity. The use of an ex-post pool with complex pricing makes this the most complex of the options proposed. This could have adverse affects with respect to participation where some traders could elect not to participate due to the complexity of the arrangements.

5.2.7 ENVIRONMENTAL

As indicated previously, the uncertainty with respect to where the liquidity concentrates across the different market timeframes means that there is insufficient detail at this point to meaningfully comment.

5.2.8 ADAPTIVE

The comments provided in respect to option (1) apply equally to this option.

5.2.9 THE INTERNAL ELECTRICITY MARKET

Like option (1), this design aligns with the Target Model in that it delivers day-ahead and intraday market arrangements in accordance with the requirements of the NC CACM. Full alignment with the NC EB is not clear and it is likely that a market designed with an ex-post pool element will require further redesign to ensure the NC EB's requirements are fully delivered.

NC EB sets out requirements for sharing of cross border balancing products with the long term vision that all products will be shared. There is also provision for unshared bids for balancing but the Target Model does not foresee this as enduring (NC EB - Section 2, 8 (b)). The description of the system operation regime under this model as using the Integrated Scheduling Process means that provisions for central dispatch systems can apply, although a methodology of converting complex bids will be required to be developed which adds to implementation complexity.

The key to this option is whether it can deliver a central solution. The market as described includes volume limitations in the ex-ante markets to concentrate liquidity in the ex-post pool. It is essential, given the system operation regime proposed, that over 50% of the active market remains in the central arrangements. This figure must be made up of price makers. If a large portion of the participation in the ex-post pool is based on price taker nominations, such as wind generators, it is unlikely that this can be classed as a "central dispatch" market and therefore unlikely that the relevant sections of the NC EB can apply. The Consultation Paper acknowledges that the ability of this design to work is dependent on the liquidity of the pool based arrangements (paragraph 7.4.3); however, elsewhere the concern is expressed with respect to actions that may detract liquidity for the day-ahead market. Paragraph 7.4.46 suggests that measures to promote liquidity in the day-ahead markets will be proposed during the next phase of the project. Promoting liquidity in the day-ahead market would have detrimental effects on the success of the pool based arrangements in this model, reducing them to an extremely complex set of balancing arrangements and potentially impacting on the dispatch arrangements.

The application of volume limitations to day-ahead and intraday cross border markets needs to be carefully considered to ensure there are no issues with respect to legislation around the free exchange of goods and services across borders. This means that alternative liquidity attracting measures may be required to concentrate trade in the ex-post pool.

If it is considered that this model can use the provisions allowed under the Integrated Scheduling Process, regardless of the liquidity in the market places, then this implies that the scheduling process can unpick all market positions rather than just those unscheduled in the forwards and day-ahead markets. This potential is noted in the Consultation Paper by reference to the inclusion of shut-down costs in complex bids. Differing from the shut-down costs used in the SEM today (which are a demand side units' version of a start up cost), these represent the cost of instructing a generator off from a position won in the forwards or day-ahead market. As such, this market has the potential for the TSO to completely overwrite the results of the earlier market timeframes. European firmness rules will mean that generator nominations will be financially settled with some form of alternate payment to acknowledge the variance in dispatch (similar to constraint payments in the SEM). When viewed in this light, the forwards, day-ahead and intraday trading begins to be financial rather than physical. In this manner, these arrangements start to look more like option (4). The notable difference with option (4) is that traded positions in the ex-ante markets will be reflected as price taker volumes in the ex-post pool while in option (4) volumes are determined by the ex-post pool independently. In option (2) the TSO may have to countertrade against some market positions, which is not required under option (4).

5.2.10 OPTION 2 CONCLUSION

As written, it is difficult to see how this option can successfully deliver on the objectives of the high level design. It could initially be viewed as a modification on the first option but using a complex ex-post pool in place of simpler balancing arrangements. The key success of this market design is where the liquidity concentrates. However, as the liquidity moves around this option, it begins to look like one of the other three designs presented, for example:

- if the forward bilateral arrangements dominate, this begins to look like option (1) but with more complex arrangements in the ex-post timeframe;
- if the day-ahead market dominates, this begins to look like option (3) but with portfolio participation and more complex arrangements in the ex-post timeframe;
- if the pool dominates, this begins to look like option (4);
- if the pool can be used to unpick the day-ahead and intraday positions, this begins to look like option (4) as European market positions become financial instead of physical.

Like option (1), this makes the market's success dependent on external intervention. As such, while suffering from the same issues as option (1) in terms of transparency, competition and efficiency, this market also has greater issues with regard to stability. The complexity of the market may serve as an additional barrier to entry, or may incentivise trade away from the more complex areas of the design, such as the ex-post pool. The fact that this design option has not been implemented in the world today represents a significant risk as there is no working model to measure against. The Consultation Paper notes that the ex-post pricing calculation faces "challenges". As such, the practicality of implementing and running this type of market is questionable.

This market has scored poorly in our assessment and would be considered a weak option.

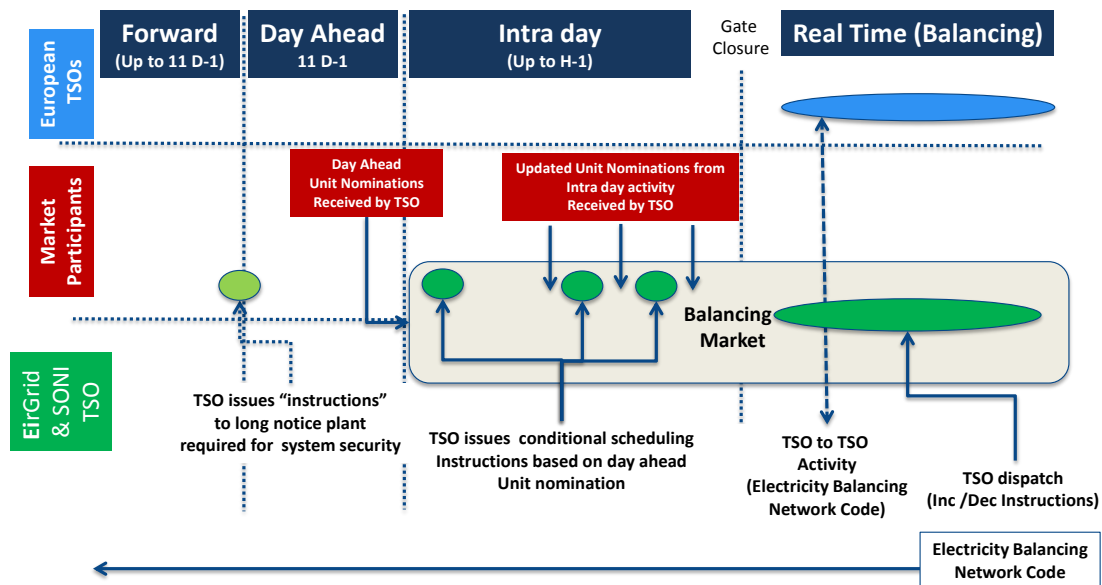
5.3 OPTION (3) – MANDATORY CENTRALISED MARKET

The mandatory centralised market option is based on concentrating liquidity in the European day-ahead market, followed by the intraday market for adjustments and concluding with a balancing market. Adopting the European day-ahead market coupling as the replacement for the central market of the SEM has the affect of using an ex-ante double sided auction to determine the bulk of the trade in the I-SEM.

The following sections outline our assessment of this option against the agreed criteria.

5.3.1 SECURITY OF SUPPLY

This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. The figure below highlights the periods where TSO activity may take place.



Unlike options (1) and (2), there is no physical bilateral trading in forward timescales. The TSOs consider that, to minimise redispatch volume in intraday timescales and to get access to long notice plant, some form of instruction may need to be developed for ensuring system security. The form and structure of this instruction would need to be developed in the detailed design phase.

From a security of supply perspective, the mandatory day-ahead has the advantage that once the day-ahead market completes, the TSOs have a complete starting point to analyse, i.e. should have 100% of the demand covered by unit nominations. Thus, all participants should have submitted their best forecasts into the day-ahead market. It is expected that the market results may not reflect actual ramp rates and hence it is anticipated that, although the TSOs receive the unit positions at the same time as participants (allowing the TSOs to start to analyse for system security), participants will update the outputs from the day-ahead market results to reflect the dynamics of the plant. It is a key requirement that there are no step changes in unit nominations which are not physically feasible and make frequency control difficult. The TSOs will analyse the unit nominations to ensure a feasible solution with minimal changes to the unit nominations. The TSOs will make changes accordingly subject to agreed tools which are essential for the TSOs to manage redispatch across intraday timescales. Across the intraday, the TSOs expect that participants will refine their positions subject to market price changes and updated forecasts. Accurate and timely unit nominations are required for ensuring system security and the TSOs would expect unit nomination updates to be communicated as soon as practicable.

With the day-ahead being mandatory, it is unclear whether sufficient liquidity will exist in the intraday for participants to refine positions and for renewables in particular to respond to changes in forecasts. In the balancing market, the TSOs may have difficulty in economically optimising a feasible solution if Inc & Dec prices changed materially close to gate closure. The comments made in option (1) with respect to price changes apply equally to this option.

When the intraday market completes, the TSOs will ensure real-time balance by Inc & Dec instructions to local participants and also via TSO to TSO activity subject to the requirements

within the NC EB. At some point in the future, Automatic Generator Control (AGC) may be required.

5.3.2 STABILITY

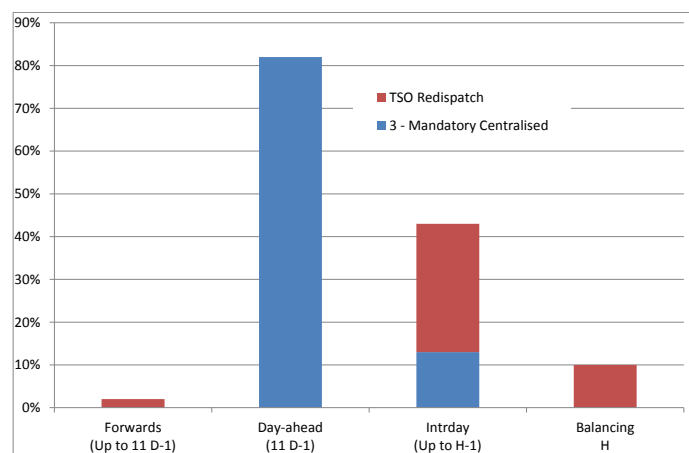
This option adopts the European day-ahead coupling market as the principal market for trade for all units within the I-SEM. In Europe, unit participation at day-ahead can be seen in the MIBEL (Iberian Peninsula) arrangements. In MIBEL, participation at day-ahead is considered pseudo-mandatory in that it is not explicitly mandatory but is strongly encouraged by linking payments from the capacity remuneration mechanism to volumes traded on the day-ahead. The Consultation Paper provides no insight as to how participation at day-ahead is mandated and paragraph 8.4.33 explicitly notes this detail and defers this issue to the detailed design/implementation phase of the project. Also, the intraday market in this model is the EU continuous trading model, which differs from the current MIBEL design where intraday is a series of local auctions (currently six are run across the trading day but it is proposed to move to hourly auctions). As such, there is no current example of a market like this in Europe.

However, because the MIBEL market area will be joining the NWE coupling later in 2014 and therefore will adopt the intraday continuous arrangements when they apply, it is expected that arrangements of this nature will be well bedded down by 2016.

As such, looking forward we would expect this design to be a stable market subject to EU governance.

5.3.3 EFFICIENCY

The volume of redispatch required by the TSOs due to transmission system constraints and reserve requirements, which is common to any future design, is difficult to quantify at this stage. The volume of this redispatch is difficult to quantify at this stage.



A qualitative assessment is shown above based on assumptions of where participants could trade (shown in blue). This is highly subjective and could change significantly depending on the rules in place. In this option, the majority of redispatch by the TSOs is likely to occur across intraday timescales once the day-ahead market completes. It is expected that at gate closure all participants would have a balanced position and hence in real-time, the TSOs are

redispatching to further optimise (via some form of Economic Dispatch algorithm) and manage the frequency. As indicated in Section 5.3.1, with the day-ahead being mandatory, it is unclear whether the liquidity will exist in the intraday for participants to refine positions (and for renewables in particular to respond to changes in forecasts) so that all participants are indeed balanced at gate closure.

The TSOs consider that redispatch volumes are likely to be higher than currently experienced under SEM. This is due to the current SEM complex bids that allow for a complete optimisation. It is also uncertain if all participants will deliver feasible unit nominations to the TSOs.

The costs of these redispatch actions in real-time will depend on the Inc & Dec prices submitted by participants and the changes in these prices up to real time balancing. The TSOs would anticipate that, as a minimum, all Inc & Dec prices (along with changes) would be fully transparent with perhaps rules on what is allowed e.g. price changes close to gate closure, price changes after being instructed etc.

5.3.4 PRACTICALITY/COST

The comments provided in respect to option (1) apply equally to this option.

5.3.5 EQUITY

The mandatory participation in the day-ahead market for all generation improves the equity of risk sharing under this option. This should reduce the volume of imbalance energy to be settled in the ex-post market. The mandatory inclusion of all participants in the day-ahead and intraday algorithms should result in a more efficient result than would be achieved under the other options.

5.3.6 COMPETITION

Centralised markets provide strong liquid market places, with transparent trading and pricing. If portfolio players are allowed to trade as net portfolio, they can dilute the liquidity by only trading their net requirements; however, compelling trade as gross portfolio or unit based can mitigate against this. Therefore, dominant portfolio players lose some of their advantage over smaller participants resulting in a more level playing field. This encourages market entry as a new participant has full visibility of prices and market activity and is not compelled to find trading partners before market entry.

Unit based participation also provides for better monitoring of any bidding code that is applied in the I-SEM, thereby facilitating a fairer and more stable market. With respect to unit participation and trading by non-physical players, we would consider that this is not an issue. The SEM as it exists today is a unit based market with, on the demand side, Supplier Units used to manage the aggregation of a number of demand sites. As such, a Supplier Unit is a portfolio representation. In this option, as in any that adhere to the European arrangements, a participant can purchase energy in the day-ahead market. If a Supplier Unit is making this purchase, it must be the case that they can trade away from this position as their demand forecast changes. Therefore, once a Supplier Unit has purchased a volume in

the day-ahead, they can re-trade that same volume in the intraday market. In this manner, non-physical players can participate in a unit based market, purchasing energy for delivery in the day-ahead market and then re-selling this in the intraday market.

This market is also based on simpler rules than the ex-post pool options which can prove attractive to new entrants.

The mandatory nature of this market may represent a problem for some players, particularly those with positions based on forecasts which are produced between 12 and 36 hours from delivery hour. These players (wind generators, Supplier Units, etc.) will now be required to prepare forecasts, submit these to the Nominated Electricity Market Operator (NEMO) along with prices (for offers/bids which can be at floor/cap if the unit is trying to represent a price taker position). This represents a change in business practice for SEM participants where wind generation and Supplier Units are price takers. Wind generators would also have to actively manage their positions in the intraday market to avoid exposure to the balancing market. Smaller wind players may be disadvantaged by the volume of activity expected of them under this kind of market. As noted elsewhere, provision for a market aggregator function could mitigate against this issue.

Mandatory participation also means that activity in the intraday market is based around adjustments. This could lead to generators and supplier units trading long positions and being exposed at the balancing market. However, if mandatory participation does not extend to the price that is bid in, but rather focuses on the volume, then a participant, mandated to trade at day-ahead stage, can bid in 100% of their forecast but price it in decremental blocks. For example, the first 50% which they are sure to need is priced as Price Cap/Floor and therefore guaranteed to be cleared. The next 25% which is strong but less certain is bid in at a price around the marginal price meaning this is likely to be accepted but not guaranteed. The last 25% which is the riskiest amount can be bid in at a level that should ensure that it is not cleared. This would fit the requirement for mandatory participation while permitting participants with unpredictable resources to place a value on their purchase. However, reducing the mandatory participation reduces the effectiveness of this design.

5.3.7 ENVIRONMENTAL

This option is based on a balancing market design and hence the comments and views in relation to option (1) apply equally to this option. As this has a mandatory day-ahead, the accuracy of the day-ahead forecast of renewable output will be key as it is uncertain how liquid the intraday may be.

5.3.8 ADAPTIVE

The comments provided in respect to option (1) apply equally to this option.

As this design is heavily integrated with the European market arrangements, implementing adaptations will be subject to the governance arrangements that apply.

5.3.9 THE INTERNAL ELECTRICITY MARKET

This option is very closely aligned with the Target Model and contains many of the characteristics of the existing European markets. By concentrating volume on the European day-ahead and intraday arrangements, this ensures this option is in line with the Target Model with respect to these timeframes, though the mandatory nature of the day-ahead arrangements is something that we understand will be unique to the I-SEM. However, it should be noted that comments on option (1) in respect of implementation of the requirements of the NC EB apply equally to this option.

While some EU markets operate with high liquidity in the day-ahead market, this is incentivised through the use of liquidity attracting measures. It should also be noted that the NC CACM in its discussions on intraday regional auctions is mindful of measures that impact on the liquidity of the intraday market. This option makes the intraday market an adjustments only market which may be seen as impacting on its liquidity.

The allowance of Financial Transmission Rights (FTRs) in the forwards timeframe is an efficient implementation of the market requirements of the NC FCA and reserves interconnector capacity for the day-ahead market, providing better liquidity. The issues noted with respect to the balancing arrangements in option (1) equally apply to this option and it is likely that further work will be needed to the balancing arrangements to ensure they fully align with the EU arrangements.

Because the full market participates in the price coupling algorithm, this should result in price-based flows on the interconnectors; however, the mandatory nature of the day-ahead means that the first cross border schedules are being set based on wind forecasts that are calculated from 12 to 36 hours in advance. This may result in interconnector flows that require adjustment in the intraday markets.

In this option, the participant is expected to enter the intraday market to avoid this curtailment. This will put a heavy onus on small variable generators to manage their forecasts throughout the day and attempt to avoid curtailment or exposure to the balancing market. The use of a market aggregator for small wind players as discussed earlier could mitigate this issue.

5.3.10 OPTION 3 CONCLUSION

This design reflects some European arrangements such as Nordpool or Mibel, where the day-ahead market is seen as pseudo-mandatory. Because the proposed model is unit based, it is more similar to Mibel than to Nordpool. While this design has proved successful in Europe, our understanding is that no market has made participation fully mandatory in the manner proposed in the Consultation Paper. Nordpool allows additional bilateral contracting as long as zonal borders are not affected. Mibel also allows bilaterals but ties payments for capacity to participation in the day-ahead auction. As a result, participants voluntarily participate at day-ahead, most probably because it has been made attractive.

By virtue of being a transparent day-ahead auction, this market design option appears better than previous options in terms of competition, efficiency and transparency. Also, by using less complex ex-post arrangements it has the potential to attract new investors. Financial

traders could be accommodated using the Supplier Unit or Interconnector Unit model from the SEM. A key issue with this option is the mandatory participation of unpredictable resources at day-ahead. Both wind players and retail supply companies will be mandated to participate by offering and bidding in their full forecast positions from 12 to 36 hours before delivery hour. This may present issues for some players and force activity in the intraday market as they have to unpick previously cleared positions. This could be mitigated by allowing unpredictable resources participate up to a best guess level at day-ahead with the option of further purchases and sales in the intraday markets as their forecasts become more refined.

The use of market aggregators could be of benefit for small wind generators in a balance responsible market.

We believe this market design option can be improved by the development of rules on participant pricing in the balancing market.

While this option is seen as arriving at a less efficient dispatch, more clarity around the nomination process could resolve this. Using the results of the European coupling algorithm as the starting point for system dispatch will result in unit positions that are further from the physical dispatch than those used today. This is because the European coupling algorithm will take less consideration of the technical characteristics of physical generators than is the case in the SEM.

We feel that this market scores well against the assessment criteria and would be one of the better of the proposed designs. However, the methods required to mandate day-ahead participation are not covered in the Consultation Paper. It is acknowledged as something that has to be addressed in the implementation phase but its' absence means that there is no clear pathway for putting this market in place which could pose significant risk for the implementation phase if solutions for these cannot be found.

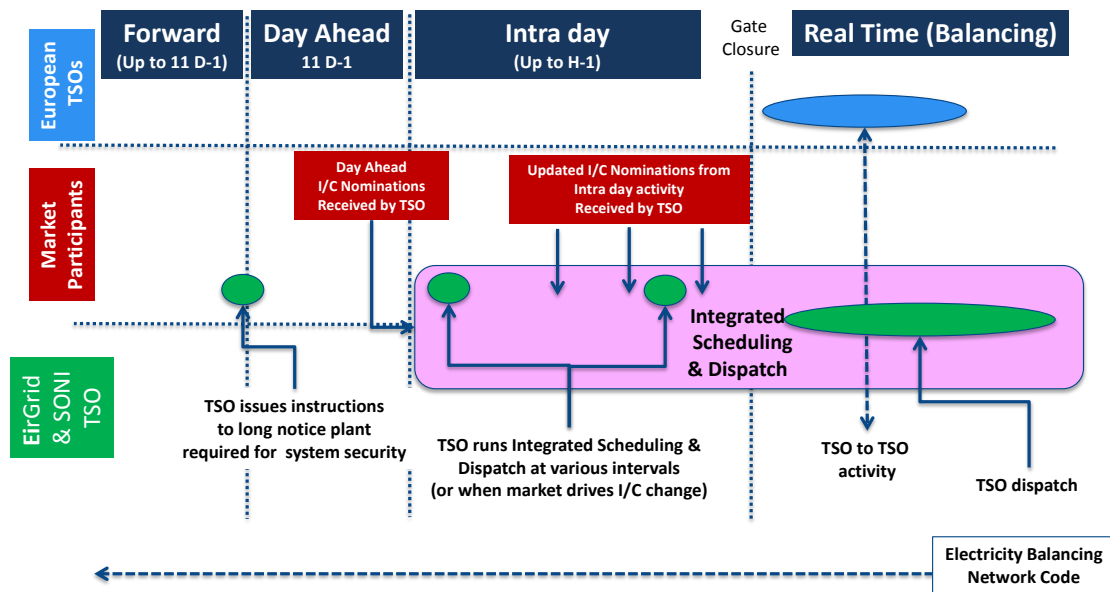
5.4 OPTION (4) – GROSS POOL – NET SETTLEMENT

The gross pool - net settlement market option takes a lot of the characteristics of the SEM and overlays financial coupling in the day-ahead and intraday markets. As such, it is similar to the SEM but without the Ex-Ante and Within-Day market runs.

The following sections outline our assessment of this option against the SEM Committee criteria.

5.4.1 SECURITY OF SUPPLY

This market design does allow the TSOs to maintain security of supply subject to having the appropriate tools in place to allow redispatch in a timely fashion. The figure below highlights the periods where TSO activity may take place.



Unlike options (1) and (2), there is no physical bilateral trading in forward timescales. With reduced time to determine feasible solutions than under the current SEM, the TSOs may require the capability to instruct long notice plant. The form and structure of this instruction would need to be developed in the detailed design phase.

With the day-head market determining only interconnector flows, the Integrated Scheduling Process determines schedules and dispatches for plant on the island. With a continuous intraday for updating interconnector flows, the volumes of these changes and how they would be reflected by the physical plant in the market to ensure a feasible dispatch are unclear to the TSO.

In real-time, TSOs will issue dispatch instructions and there will be TSO to TSO activity subject to requirements of the NC EB. At some point in the future, the TSOs may require Automatic Generator Control (AGC) to automate the dispatch process in real time balancing.

5.4.2 STABILITY

This option takes a lot of the ex-post design of the current SEM and matches it with financial trading at day-ahead and intraday. The SEM is a stable market design that has been in operation for seven years and has many characteristics of the standard pool market model. The removal of the current ex-ante and intraday market runs should reduce complexity in this market but this leaves cross border trade to be calculated from the results of financial trading on the European markets. This market also relies on the Integrated Scheduling Process to determine the day-ahead schedule. This is largely the central dispatch model that is currently in use in the SEM.

Risks to stability of this market are that there is no working model in Europe. This market contains elements that are similar to the Polish market model (POLPX) which uses an Integrated Scheduling Process with financial trading on the intraday market; however, Poland does have a physical day-ahead market with ex-post balancing arrangements.

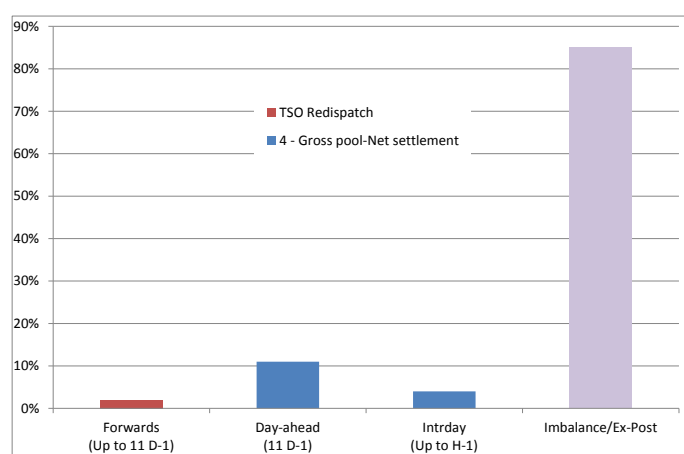
With EU prices setting the cross border flows independently of local market pricing, there is a risk that price convergence may not occur between the I-SEM and the rest of Europe which

may lead to counterintuitive flows on the interconnectors; however, financial trading at day-ahead and intraday may mitigate against this. The implementation of NC EB is anticipated to be more complex under this option due to a requirement to have an agreed methodology to convert complex bids into standard products. It is possible that this market design may require further redesign during the implementation of the balancing market arrangements after 2016 which may impact on the long term stability of this market.

5.4.3 EFFICIENCY

The volume of redispatch required by the TSOs due to transmission system constraints and reserve requirements, which is common to any future design, is difficult to quantify at this stage. A qualitative assessment is shown below based on assumptions of where participants could trade (shown in blue) with the ex-post pool being dominant (purple).

With interconnector volumes being initially set at day-ahead the majority of scheduling is via the Integrated Scheduling Process as under current SEM.



The Integrated Scheduling Process allows for a full system optimisation taking into account interconnector nominations. This would be rerun as interconnector nominations or as market prices change. At this stage it is not known whether there would be a bidding code of practice as under current SEM.

5.4.4 PRACTICALITY/COST

The comments provided in respect to option (1) apply equally to this option.

5.4.5 EQUITY

Under this option, participants cannot fix their physical position ahead of time. While this should result in the lowest theoretical production cost of the four options, it does not result in as equitable a sharing of risk as options (1) or (3). In particular, a party may be successful in a European auction, but this result would not be considered when calculating the local schedule. Given that the bid format under the European arrangements is expected to differ from the local ex-post pool, the commercial position may not be adequately reflected in local payments. This option does not provide as equitable an allocation as option (3); however, it is also not as inequitable as options (1) and (2).

5.4.6 COMPETITION

As with option (3), the centralised nature of option (4) should promote better competition by promoting a more transparent marketplace with clear pricing and an easier route to market for smaller players. This option would provide a strong liquid ex-post pool which has benefits for retail companies and smaller generators. Because this option is largely based on the current SEM arrangements with a provision for financial trading at day-ahead and intraday, it could be said that this model encompasses all the positive aspects of the SEM today.

However, it could also be said that it retains the negative aspects of the SEM, such as the complexity of the market schedule and price. SEMO have published a number of papers on the complexity of the algorithms used for determining the ex-post pool market schedules and the system marginal price. As noted in these, the derivation of the shadow price is not always as transparent as hoped, in some cases being driven by the algorithm's interpretation of ramping constraints. The complexity of the pool has the potential to act as a barrier to entry if it became difficult for investors to secure financing for projects where the stability of the pool price can be prone to fluctuations driven by technical characteristics that are not immediately transparent. In this light there are benefits of a simple double sided auction as used in option (3).

While the central market provides transparency and a level of competition, the European aspect of this is based solely on financial trading. As such, it is unlikely to provide any major benefits to smaller independent players. While wind generators and retailers can avoid the risk that comes with more active participation on the day-ahead market, they equally lose out on the opportunities to trade across borders into the wider European market. Limiting these markets to financial trades only has the potential to be of benefit to larger established players, who have the capability to trade financially, and pure financial trading entities. While not specifically disadvantaging smaller players, it could impact on the potential for the European prices to fully integrate back into the I-SEM where other options allow physical traders within the I-SEM direct participation on the European markets. This could also limit the incentive on smaller wind farms to manage their own balanced positions through the intraday markets when these positions may not be realised physically.

Overall, while providing a good competitive marketplace this option may not realise all the benefits to be gained from full participation on the European markets.

5.4.7 ENVIRONMENTAL

The TSOs consider that under this market design, the volume of countertrading has the potential to grow as more renewable generation connects and more of the onus will be on the TSOs to minimise curtailment of renewables than under other market design options where it is considered that participants will be able to use the intraday market for this purpose. It is possible that financial traders in the intraday market may take advantage of arbitrage opportunities which could counter this.

With the volume of renewable generation expected to connect in the future, the design should encourage participants to use market mechanisms to reach a balanced position with interconnector flows reflecting this.

5.4.8 ADAPTIVE

The comments provided in respect to option (1) apply equally to this option.

Because this option includes a local ex-post pool market, implementing change to this model may only require local approval.

5.4.9 THE INTERNAL ELECTRICITY MARKET

This design seeks to implement the Target Model through the use of financial trading at day-ahead and intraday. The closest European market to this appears to be the Polish design which uses financial arrangements in the intraday. This market has led to a number of issues being raised in the NC EB to address the requirement to close out positions in the centralised market arrangement while the cross border balancing markets remain open. This has led to the development of additional rules for central dispatch markets which could apply to the I-SEM under this option, such as freezing balancing bids in advance of the balancing market gate closure.

While the market can provide for an efficient scheduling process for the TSOs, there is no incentive on the market players to keep balanced positions. With the day-ahead and intraday markets managed as financial contract markets, it is possible that liquidity will not materialise. This being the case, we can expect that only "explicit" interconnector users will act in the day-ahead and intraday markets as other physical users cannot translate their market position into a physical position. This may have adverse impacts on the liquidity of these markets and may not produce the proper incentives for wind generators to avoid curtailment through intraday trading.

The Consultation Paper notes that this option requires side payments to participants who secured positions in the ex-ante markets; however, it does not take account of the possibility that a participant may not secure the desired volume in the ex-post market. In this case, the participant is exposed to a volume risk. Settling the day-ahead and intraday positions as side payments also means that the cross border interactions do not fully integrate into the I-SEM. Cross border flows are determined through a subset of trades at day-ahead and intraday while the final market reference price comes from local trading where these positions are just inputs into the calculation; the prices bid and offered for the cross border flows may not appear in the I-SEM price formation.

While offering a number of advantages given the unique characteristics of the SEM which will continue in the I-SEM, it is unclear whether this option delivers the full potential benefits to the consumers in Ireland and Northern Ireland as the European prices may not be integrated in the I-SEM.

5.4.10 OPTION 4 CONCLUSION

This design retains a lot of the current SEM arrangements such as an ex-post pool, single marginal pricing, day-ahead central scheduling and dispatch. In principle, this would ensure that those elements of the SEM used to meet the principles of the original SEM HLD from 2005 are applied in the same manner for the I-SEM HLD. This means this option delivers good transparency, fosters competition and should deliver an efficient least cost dispatch solution.

However, issues with the current SEM, such as how it can accommodate the large volume of wind generators that will be needed to meet 2020 targets are not addressed. Arrangements for TSO countertrading of curtailable volumes of wind would be likely to persist and even increase under this option as the lack of balance responsibility in the pool could mean that generators are not incentivised to manage their own position.

A further risk with this market would be its stability. It is foreseen that the I-SEM would need to be adapted over time to conform to the European rules on electricity balancing. Given the current proposals in the NC EB, it should be expected that this option may face a further significant redesign to align with balancing arrangements which will be implemented in stages from 2016 through to 2021.

Using the day-ahead and intraday as financial markets, but where the interconnector flow is fixed, represents a challenge for this model. It means that interconnector flows are determined by a separate pricing mechanism than the rest of the market, which may result in counterintuitive flows. It is unclear in this option how the European price is integrated into the I-SEM and therefore whether the benefit of market coupling will be fully realised for consumers.

We feel that this market scores well against most of the assessment criteria. While this option is an appropriate design for our electricity market, there are a number of issues which need to be resolved such as the full integration of the European prices back into the I-SEM and whether financial traders will emerge and trade in ways that deliver efficient interconnector flows based on market results.

5.5 CONCLUSION ON ENERGY TRADING ARRANGEMENTS

In our review, we broadly agree with the assessment of the RAs as expressed in the Consultation Paper.

We believe options (1) and (2) have significant and rather similar drawbacks as both designs are heavily dependent on external interventions to determine where liquidity pools, which will impact on the stability of these designs. Both have the potential for liquidity to pool in non-transparent, out of market, bilateral arrangements which may not suitably promote competition either for independent market players or consumers. Arrangements where cross border trades can be struck independent of central price based arrangements may lead to inefficient flows. The significant difference between these options is the ex-post arrangements where option (2) includes a complex ex-post pool which may not attract sufficient liquidity. Potential improvements to these markets, such as mandating

participation in the balancing market in option (1), will only move them closer to the centralised options proposed.

We believe options (3) and (4) provide stable markets with good transparency which will lead to better competition and therefore are more suitable choices for the I-SEM. In this light, given its strong liquid day-ahead market, the use of a balancing market that reflects the actual cost of operating the system and the full integration of the European day-ahead and intraday prices in the I-SEM arrangements, option (3) has the potential to deliver more competition in the marketplace as well as price reflective cross border power flows. These potential benefits are however tempered by a number of other factors including more active participation for smaller generators, more requirements for wind generators to manage their position and potentially less efficient dispatch arrangements. If the actual benefits outweigh these drawbacks or these can be addressed through additional features such as the use of market aggregators for small wind generators then, based on our analysis against the assessment criteria, option (3) offers the best longer term benefits for consumers in Ireland and Northern Ireland.

6 CAPACITY REMUNERATION MECHANISM (CRM)

In this section we discuss whether a CRM is a necessary requirement for I-SEM. We then present our analysis of each of the CRM options and provide our overall conclusion on the options.

6.1 REQUIREMENT FOR A CRM IN I-SEM

The first step that should be taken before any capacity mechanism is introduced is to ensure a well functioning energy market in line with the Target Model. This should provide the correct short term signals to generators and demand. In this regard, the exposure and ability of all generation and demand to respond to the energy price signal should be maximised. In particular, the continued development of demand side management is of key importance here.

Another important factor is that interconnector flows are scheduled in line with the spread between the prices on either side of the interconnection. This introduces additional elasticity to the demand. This will occur until there is congestion, at which stage the scarcity value of the cross border capacity increases above zero. This is analogous to an energy only market implicitly valuing generator capacity only at times of scarcity.

The problem of missing money is one of energy revenues not meeting the cost of producing the energy – both investment and variable costs. In addition to energy, however, a generator provides a number of important system services to aid with the delivery of the energy. So not only does it transform the energy from one form into electrical energy, it also provides a number of services that are essential to the transmission and distribution of this energy (e.g. reactive power for voltage support, inertia to reduce the rate of change of frequency). While the customer is interested primarily in energy, they are also interested in reliable energy. If reliability has value, and reliability is a function of the availability of a set of essential system services, it follows that this value should be placed on these system services to ensure investment not just in adequacy but in reliability. EirGrid's recommendations on systems services as part of DS3 specify the services required and advocates placing a much higher value on these essential services. More detail on these system services is provided in Appendix A.

By 2020, Ireland and Northern Ireland intend to have 40% of their electricity consumption coming from RES, with 37% coming from wind. Operating a single synchronous system with this level of wind generation is unprecedented and will require a portfolio of complementary units, active demand side and flexible interconnector trading. A well functioning integrated energy market is paramount to achieving this objective but may only serve to ensure the efficient short term operation of the existing portfolio. In our view, complementary long term arrangements that promote the right kind of investment are necessary. At a time when the system is undergoing a fundamental transformation, under investment could have major implications in our ability to deliver a secure sustainable system.

In this regard, we believe that a capacity mechanism should be retained but redesigned in the context of the overall review of energy and system services to:

- **Ensure overall value for money for consumers.** A consistent approach across all revenue streams is imperative in this regard, e.g. the SEM capacity mechanism reflects the requirement to submit cost reflective offers to the energy market and includes a provision for ancillary services revenue. Energy, system services and capacity revenue should reflect their overall value.
- **Promote good behaviour, drive efficiency and promote innovation.** Any well designed capacity mechanism should reduce investment risk, while retaining a sufficient amount of commercial risk to ensure reliable and efficient performance. The mechanism should also provide the appropriate signal to exit the market.
- **Promote more efficient cross-border trade.** In the context of the Target Model, a well designed capacity mechanism should not distort the efficient cross-zonal flow of energy. Furthermore, to promote investment, cross-zonal capacity (i.e. interconnection) should be rewarded to the extent that it contributes to adequacy.

Investment in generation capacity can be expected to last 15-20 years; the associated network investment expenditure to facilitate its physical dispatch and market access more like 40-50 years. EirGrid is therefore of the view that non-energy payments introduced to promote investment in capacity or system services when there is a scarcity should not simply be removed when there is a surplus. This approach risks undermining confidence in the long term stability of the arrangements and could introduce security risks. If this were to occur, it would not be simply a case of reintroducing a mechanism again as rebuilding investment confidence will take many years. Instead, our view is that non-energy revenue in the form of system services and a capacity mechanism should form a permanent and stable component of the long term trading arrangements.

The primary motivation behind the introduction of any capacity mechanism is to meet administratively-determined resource standards within liberalised electricity markets, where generation decisions are made by merchant investors rather than regulated entities. It should be noted that there is no real world example of an energy only market. All markets that do not feature capacity mechanisms rely on various out of market mechanisms to meet reliability standards and most include price caps at levels well below the level required to let market forces choose the desired level of reliability³.

Capacity mechanisms are introduced to fill the missing money gap that arises primarily from three phenomena – large discrete ('lumpy') investments, demand inelasticity and price caps.

Large discrete ('lumpy') investments are a characteristic of electricity generation business and these investments incur large capital costs. Given the nature of the investments they are largely irreversible and therefore subject to hurdle rates as characterised in Real Options theory. The missing money problem arises where average energy prices reflect short run marginal costs (SRMC) whereas investors require long run marginal costs (LRMC) that include the cost of making the investment. In theory, in periods of scarcity, prices will rise above SRMC; however, in order to bring the average from SRMC to LRMC, the prices at these times need to be very high and will be higher in the future as the percentage of zero

³ Pfeifenberger et al. (2009) - A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs (http://brattlegroup.com/_documents/UploadLibrary/Upload807.pdf)

variable cost renewable energy increases. This introduces a level of volatility to energy only markets that is often too much for investors.

Demand inelasticity refers to the lack of response of demand to increase in prices. At very high prices, some demand may opt to reduce instead of paying the high prices; however, as much of the demand side is not exposed to or not equipped to respond to the high prices, it does not have the opportunity to respond. In this instance, the high prices are creating an incentive to build too much capacity. The continued development of demand side responsiveness within the wholesale market arrangements is essential to ensure the efficiency of these arrangements as the current levels may not reflect the end users willingness to reduce their demand at times of high price. The development of time of use meters is an important consideration here to ensure that those who want to be exposed to the wholesale price have the capability to do so.

Price caps refer to the administrative capping of prices at what are regarded as 'acceptable' levels. Without a responsive demand, the potential for the exercise of market power increases. The less demand responds to price the more generators can increase price margins without losing volume. This is a significant market power issue in electricity markets and price volatility can be orders of magnitude higher than other commodities markets. Wherever there are very high prices, there will always be a concern that these high prices derive not from competitively priced scarcity, but instead higher infra-marginal rents that result in prices above the average LRMC. In order to address this, price caps are often introduced to limit the extent of the price spikes. As price caps are determined administratively, they may be lower than the level at which the demand would have voluntarily reduced. Even in the absence of such measures, investors will tend to discount their future cash flows with the expectation of regulatory risks. So whether it is a price cap or the potential of a price cap, investors perceive missing money and do not invest. All the market zones in the NWE have adopted a price cap of 3000€/MWh. It may be necessary that the SEM Committee adopts this price cap as part of the I-SEM arrangements.

On the basis that the above conditions are likely to continue to exist in the I-SEM, the issue of missing money may be unavoidable and investors may not be confident enough to invest (especially when there is a global market for these types of investments).

EirGrid believes that an energy only market is not sufficient to provide the necessary long term signals to attract the appropriate level of investment to ensure security of supply and deliver on policy objectives. In our view, promoting investment in system services that enhance power system stability and control in the presence of increasingly significant levels of wind generation is essential. As a complement to energy and system services revenue, our view is that a market-wide quantity-based capacity mechanism is a pragmatic approach to assuring revenue adequacy and a reasonable degree of predictability for investors and delivering long term value for customers.

6.2 ASSESSMENT OF OPTIONS FOR THE I-SEM

A variety of capacity mechanisms exist in electricity markets across the world (including in the SEM) and it would be important to learn from the strengths and weaknesses of these arrangements. There is a diversity of views as to which options represent the most effective

approach to attracting the right amount of investment. We will deal firstly with our views on options (1) and (2) before proceeding to a discussion on why we believe that quantity based options are more suitable for the I-SEM.

6.2.1 OPTION (1) – A STRATEGIC RESERVE

Strategic Reserves are in place in Norway, Sweden, Finland, Netherlands, New Zealand and recently, Germany, on a temporary basis pending consideration of a more comprehensive approach.

We believe that a Strategic Reserve, as a simple and relatively inexpensive measure of assuring a desired level of reliability, has merit under certain conditions. These conditions include situations where it is reasonably expected that the market will not deliver the required investment in the timescale or location necessary to ensure continued secure operation.

A Strategic Reserve may also be useful in attracting non-conventional technologies (such as batteries, flywheels, novel demand response, etc.) that provide capacity and services but may have limited appetite for the complexities of the energy market. This would need to be carefully considered beside the proposed products set out under the programme for Delivering a Secure Sustainable System (DS3).

Notwithstanding the above, we would not view a Strategic Reserve in isolation as being sufficient to deliver the necessary continuous investment in flexible capacity required to deliver on policy objectives. In this regard, a broader package of system services and a market-wide mechanism in our view is necessary.

6.2.2 OPTION (2) – PRICE BASED MECHANISMS

Market wide price based mechanisms exist in Chile, Hungary, Argentina, Spain, Greece, SEM and Portugal. Price based mechanisms existed in GB from 1990-2001 and in Italy from 2004-2013.

Price based mechanisms are seen as a simple, flexible tool for promoting investment. On the other hand, price based mechanisms can result in over or under investment depending on whether the price is set too high or too low. As the mechanism is intended to be stable, it is difficult to change the level of payment without increasing the level of regulatory risk associated with the mechanism. Higher risk ultimately means higher cost as investors will need to be remunerated for this.

Option (2a) – Long Term Price Based CRM is broadly similar to the current fixed and variable components of the SEM CPM. The SEM CPM has underpinned investments in the SEM for over six years now and has been successful in raising the levels of declared availability and providing a stable income stream to investors. Nevertheless, the SEM CPM in our view has a number of shortcomings and the review under the I-SEM HLD in our view represents an opportunity to address these.

The following are areas where we believe the current SEM CPM can be improved upon:

- Administered price: As a level of reliable capacity is the target of a capacity mechanism, using a price based mechanism may result in under or over capacity if the price is set at a level that is too low or too high respectively. This may be the case currently where the amount of capacity in the SEM exceeds the capacity requirement; however, this represents only one of a number of drivers for investment in the SEM. One potential difficulty in having a mechanism where the price is set administratively is that if system services payments are also set administratively, the interaction between the two must also be set administratively. This is a complex area and adopting a central view on the how revenue streams from capacity and system services interact increases the potential to under or over remunerate investments.
- Sensitivity to parameters: While the overall payments from the CPM will more or less equal the annual capacity payment sum (aka 'the capacity pot'), the distribution of payments between participants is highly sensitive to parameters. An example of such a parameter is the Flattening Power Factor (FPF). This parameter, which lies deep within the CPM formulae, determines the slope of the quasi LOLP (Loss of Load Probability) curve used to weight some of the components of the payments. As set out in the annual analyses completed by the TSOs on the choice of this parameter, changes to the value of the FPF can result in significant changes in the level of payments to certain participants (or technology types). The value chosen aims at striking a balance between a long term stable investment signal and a short term availability signal; however, the choice of this parameter is discretionary and therefore could be perceived to increase risk as a result.
- Complexity: The current CPM is extremely complicated and it is very difficult to understand how changes in behaviour will affect the level of payments. The advantage of simplicity often associated with price based mechanisms does not apply to the SEM CPM. The relationship between eligible availability and capacity payments is highly non-linear due to the number of layers in the mechanism. Many of these are arguably of limited benefit to the overall scheme. An example of this complexity can be found in section 5 of the Trading and Settlement Code where the rules for energy limited and pumped storage units are set out.
- Barrier to cross border trade: The current approach of paying interconnector capacity on the basis of flows rather than available capacity may be contributing to the tendency of the SEM to import from GB for most parts of the day. As has been seen across many interconnectors across Europe, including in particular those from GB to mainland Europe, the removal of flow based charges related to BSUoS (Balancing Services Use of System) and TNUoS (Transmission Network Use of System) increased the level of cross border trade. In Section 3.4.5 we set out and reaffirm our view that capacity payments to interconnectors should be made to the capacity provider (interconnector owner/operator) rather than the capacity holder (interconnector user) and that only then are there appropriate overall incentives in relation to the building, and availability, of all capacity services and service providers.
- Weak exit signal: The current SEM CPM has been instrumental in increasing the levels of available generation in the SEM, in the existing fleet of generators and in

the development of new generation and demand side units. As a result, the total level of capacity across the SEM is now greater than the SEM capacity requirement that is used to calculate the Annual Capacity Payment Sum. While this is a positive development, a consequence of this is that the payment per unit of availability is now less than the required amount to attract investment in the BNE peaker. While this is intended to provide an exit signal for older less reliable units, it may not have the desired effect. Older units that have not undergone significant refurbishment in recent years may have written down their capital costs and only face their fixed O&M costs to remain in operation. On the other hand, a new unit or a refurbished older unit requires recovery of both their capital costs and their fixed O&M costs. In the absence of any significant consequences for non-performance, a situation may arise where the capacity mechanism is sufficient to keep older, less reliable units in service but not sufficient to justify investment in the refurbishment of existing units or in the commissioning of new generation and demand side capacity.

Option (2a) – Long-Term Price-Based CRM in our view would share many of these shortcomings and therefore we believe that this option should not be pursued further by the RAs.

Option (2b) – Short-Term Price-Based CRM considers adopting an approach similar to the current *ex-post* component of the SEM with the important difference that the annual capacity payment sum approach does not feature as part of this option. The payments are, as a result, unbounded. As such, this approach resembles more the capacity payment that featured as part of the old England and Wales Pool. This mechanism was found to be highly problematic due to the ability of generator units to influence the price by withdrawing capacity. This mechanism was the starting point of the current SEM mechanism and the adoption of a fixed annual capacity payment sum was intended to mitigate this risk. As such, we do not believe that an unbounded CPM based on a scarcity rent function is a suitable mechanism for the I-SEM.

6.2.3 OPTIONS (3), (4) AND (5) – QUANTITY BASED MECHANISMS

Market wide quantity based mechanisms exist in decentralised form (i.e. capacity obligations) in California and, from 2015, in France and in centralised form (i.e. capacity auctions) in PJM, New York and, from 2014, in GB. It should be noted that US auctions represent a last opportunity for suppliers to fulfil their capacity obligations; however, they may procure them bilaterally prior to this. In this regard, they are similar to obligations. Reliability options exist in Colombia and New England and are currently being implemented in Italy.

As stated at the beginning of this section, a volume based approach is our preference in terms of the proposed options. Volume based mechanisms have the immediate advantage that they enable the remuneration of a specific level of capacity, i.e. the capacity requirement. Unlike the price based mechanisms where the desired volume emerges in response to the price, in this mechanism the desired volume is set administratively and the price is set by using market based methods, i.e. centralised auctions, decentralised auctions or bilateral trades.

Setting the price using market based methods would require careful design to ensure that they were not susceptible to gaming; however, if there is sufficient competition, the market approach enables the generator to internalise revenue from other sources in their offers. This would be particularly useful in the instance that the SEM Committee adopts the recommendations in relation to system services. Increasing the importance of the system service payments will serve to increase the ability of more expensive flexible capacity to compete with less flexible cheaper capacity in the capacity market. As these flexible units internalise their expected revenue from the system services, the overall cost of capacity and system services will reduce to the level that is required to bring forward these investments in flexible capacity.

Our view is that the HLD design decision should narrow the mechanism down to a market wide quantity based mechanism. This will enable a more considered view of which of the approaches would then be most suitable.

As described in the Consultation Paper, option (3) (Capacity Auction) and option (4) (Capacity Obligation) are essentially centralised and decentralised versions of the same approach i.e. suppliers are required to procure their share of the capacity obligations necessary to ensure an administratively determined reliability standard. In option (3), this procurement takes place through a central auction. In option (4), this procurement is decentralised i.e. the suppliers can procure their capacity obligations bilaterally or through voluntary auctions. The same could be said of Option (5A) (Centralised Reliability Options) and Option (5B) (Decentralised Reliability Options).

Whereas capacity auctions and obligations represent a physical obligation on the part of the generator, Reliability Options are financial in their nature. Reliability Options are attractive on paper as they retain the energy only price signal for generators and, importantly, for demand side. Contrary to the commonly held view, Reliability Options do not represent a price cap on the energy price. At a particular price, the liability with respect to the Reliability Option of the generator is independent of their output and for every extra MWh produced, the generator's revenue will increase by the reference price (regardless of whether regardless of whether this is above the strike price of the option or not). This is an important aspect of Reliability Options that is not shared by auctions or obligations.

Reliability Options may not be suited to energy trading options (1) and (2) as these options include forward physical trading. Reliability Options rely on generators mitigating their exposure to the Reliability Option by generating at times of high prices. If they have traded their energy in the forward timeframe, they will not receive the high spot price but will still be exposed to the cost of the Reliability Option. Reliability Options may not therefore be suited to energy trading option (4) either as they rely on the presence of energy only prices that reflect scarcity rents.

Considering these options have characteristics that are also under consideration in the energy trading options, it would in our view make sense to adopt a consistent approach across energy and capacity arrangements. For example, a more decentralised approach to CRM may be more suited to the more decentralised energy trading options. Conversely, more centralised energy arrangements may benefit from more centralised capacity trading arrangements. In line with our preference for transparent centralised energy trading

arrangements, our preference would be for a transparent centralised capacity remuneration mechanism i.e. capacity auction or centralised reliability options.

6.3 CONCLUSION ON CAPACITY REMUNERATION MECHANISMS

EirGrid believes that an energy only market is not sufficient to provide the necessary long term signals to attract the appropriate level of investment to ensure security of supply and deliver on policy objectives. In our view, promoting investment in system services that enhance power system stability and control in the presence of increasingly significant levels of wind generation is essential. As a complement to energy and system services revenue, our view is that a market-wide quantity-based capacity mechanism is a pragmatic approach to assuring revenue adequacy and a reasonable degree of predictability for investors and delivering long term value for customers.

On balance, we believe that one of the four market-wide quantity-based approaches should be considered as a candidate for the capacity mechanism. In line with our preference for transparent centralised energy trading arrangements, our preference would be for a transparent centralised capacity remuneration mechanism. In this regard, capacity auctions and centralised reliability options would appear to be the more suitable candidates; however, the choice of quantity-based mechanism in our view should be taken following a more detailed assessment against the chosen energy trading arrangements. Price based options are not recommended. Strategic reserves may have merit in some cases but not as long term arrangements.

Ultimately system services and capacity together must provide for the additional revenue requirement above that provided through the energy market.

In the consultation there are references to DS3 System Services and interactions between these and the High Level Design in the real-time balancing timescale when the NC EB is in force. The NC EB relates to frequency control. It does not relate to reactive power, inertia, or system stability. Therefore the System Services products of Synchronous Inertial Response (SIR), Dynamic Reactive Response (DR), Steady-state reactive power, Fast Post-fault Active Power Recovery (FPFAPR) and Black Start are not covered within the framework of the NC EB.

The DS3 System Services products of Fast Frequency Response (FFR), Primary Operating Reserve and Secondary Operating Reserve are related to the faster process of containment of the frequency change following a system incident i.e. part of the Frequency Containment Process as established within the framework of the Network Code Load Frequency Control & Reserve (NCLFCR). As currently drafted, The Frequency Containment Process is not central to the NC EB as the NC EB does not establish a framework of models for the Frequency Containment Reserves. The NC EB is more concerned with the slower frequency restoration and reserve replacement processes.

The System Services products Tertiary Operating Reserve 1, Tertiary Operating Reserve 2 and Replacement Reserve are related to the slower processes of frequency restoration and replacement of reserves i.e. part of the Frequency Restoration Process and the Reserve Replacement Process as established within the framework of the NCLFCR. The System Services products associated with these NCLFCR processes are likely to interact with the development of Standard Products as part of NC EB implementation. The development of these Standard Products has started within ENTSO-E. It is unclear at this stage if these products will be developed on a synchronous area basis or pan-European basis. The System Services products required by the all-island power system may be compatible with some of the Standard Products although some of the physical characteristics of the all-island power system may limit the use of Standard Products requiring the use of more local Specific Products as allowed for in the NC EB.

The System Services product of Ramping Margin is not a Standard Product as described in NC EB as it does not provide containment, restoration or replacement reserves in the timeframes considered in the frequency processes. Rather, it provides certainty of margin over time periods from 1 hour to 8 hours. If Ramping Margin were to be considered under the NC EB it would only be as a Specific Product and definable specifically to meet an all-island need.

In summary, there may be interaction between some of the System Services but on the whole they are separate from the NC EB and hence the High Level Design. Market designs which incentivise or place value on flexibility may not always be available to the TSOs if being utilised by participants. System Services do have an important interaction in terms of revenue adequacy (along with energy and capacity) and the overall design should take this into account.

8 APPENDIX B – RESPONSES TO THE CONSULTATION QUESTIONS

8.1 PURPOSE OF THE DOCUMENT (SECTION 1)

Question	Answer
1. Which option for energy trading arrangements would be your preferred choice for the I-SEM market, and why?	<p>We have considered the energy trading arrangements as proposed against the criteria set out in the Consultation Paper. In this light, we have considered both from our role as system operator as well as market operator. From this perspective, we would present the view that we can operate any of these designs from the view of both a power system and a market.</p> <p>In terms of implementing the high level principles of the I-SEM, we feel that options (3) and (4), the “Mandatory Centralised Market” and “Gross Pool Net Settlement Market” best reflect the SEM Committee’s duties. In our opinion they provide a stable market with good transparency that can encourage market entry. Of these two options, option (3) - the “Mandatory Centralised Market”, provides longer term stability and a more equitable apportionment of risks.</p> <p>Further detail can be found in Section 5.5.</p>
2. Is there a requirement for a CRM in the revised HLD, and why?	See Section 6.1 .
3. 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?	See Section 6.2 .

8.2 TOPICS FOR THE HIGH LEVEL DESIGN OF ENERGY TRADING ARRANGEMENTS (SECTION 4)

Question	Answer
4. 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?	While these are important topics, the HLD paper is silent on a number of issues that would have aided our understanding of how the options interact with the SEM Committee’s duties. We refer to these in Section3.4of our response.
5. 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?	The arrangements for Forwards Capacity Allocation covering auctions of capacity in the forwards timeframe should be recognised in the HLD. The I-SEM includes the forwards timeframe as a part of its market design and includes the outputs of this process, in the form of Physical Transmission Rights (PTR) and Financial Transmission Rights (FTR) in this timeframe; however, the allocation of capacity that feeds into these FTRs and PTRs is not addressed.

8.3 SUMMARY OF THE OPTIONS FOR ENERGY TRADING ARRANGEMENTS (SECTION 5)

Question	Answer
6. What evidence can you provide for the assessment of the HLD options with respect to security of supply, efficiency, and adaptability?	The TSOs have assessed each option against security of supply from operational experience within EirGrid of having successfully operated the SEM and also from the experiences of other European TSOs. EirGrid is active in ENTSOe System Operations and benefits from the knowledge of other TSOs experiences in managing their systems under the various European Market structures. On dispatch efficiency, EirGrid has given a qualitative view based on the experience of operating a power system with the unique technical characteristics that exist on the island.

8.4 ADAPTED DECENTRALISED MARKET (SECTION 6)

Question	Answer
<p>7. 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)?</p>	<p>The balancing market should be mandatory after day-ahead gate-closure. Leaving this voluntary up to one-hour from real time runs the risk that the System Operator will not have access to plant required to run the system securely and will therefore be required to enter into out-of-market bilateral contracts which may reduce the liquidity of the main markets.</p> <p>We believe there should be bidding rules applied with respect to price changes close to gate closure, price changes after being instructed, etc.</p> <p>We believe a balancing aggregator should be considered as an entity in this market to support renewable generators.</p>
<p>8. 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)?</p>	<p>Our review against the assessment criteria is broadly in line with the assessment put forward in the Consultation Paper.</p> <p>Further detail of our review can be found in Section 5.1 of our response.</p>
<p>9. 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?</p>	<p>This option has shortcomings in terms of competition and equity criteria, brought about by the potential for the market volumes to concentrate in bilateral contracts and thereby failing to deliver transparency.</p> <p>As described in the Consultation Paper, this option risks oligopolistic behaviour which would not be in the long term interest of consumers.</p> <p>If liquidity can be effectively concentrated in the day-ahead and intraday markets</p>

without applying measures that reduce the stability of the market, then this would score differently; however, the market would also cease to be “de-centralised” and would look more like option (3)

8.5 MANDATORY EX-POST POOL FOR NET VOLUMES (SECTION 7)

Question	Answer
<p>10. 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)?</p>	<p>There are a number of adaptations that could be applied to this market design option to improve on its ability to deliver on the objectives of the HLD; however, it is our opinion that the application of these adaptations will result in this market taking on the characteristics of one of the other three.</p> <p>Further detail can be found in Section 5.2.</p>
<p>11. 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)?</p>	<p>Our review against the assessment criteria is broadly in line with the assessment put forward in the Consultation Paper.</p> <p>Further detail can be found in Section 5.2.</p>
<p>12. 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?</p>	<p>In comparing this option against the others, we feel it is the least compatible with the SEM Committee’s duties. This is due to low scoring against competition and equity criteria which arises due to the concerns as to where liquidity is pooled.</p> <p>If liquidity is concentrated away from the ex-post pool, then it is unclear if the proposed scheduling arrangements are consistent with the market arrangements.</p> <p>Further detail can be found in Section 5.2.</p>

8.6 MANDATORY CENTRALISED MARKET (SECTION 8)

Question	Answer
13. 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)?	<p>A drawback with this market is access to long notice plant by the System Operator. If this could be adapted to allow the System Operator physically contract with long notice plant before the day-ahead, this has the potential to improve on the dispatch efficiency of this model.</p> <p>We believe there should be bidding rules applied with respect to price changes close to gate closure, price changes after being instructed, etc.</p> <p>We believe a balancing aggregator should be considered as an entity in this market to support renewable generators.</p>
14. 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)?	<p>Our review against the assessment criteria is broadly in line with the assessment put forward in the Consultation Paper.</p> <p>Further details can be found in Section 5.3 of our response.</p>
15. 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?	<p>We consider this model to be the one that is most compatible with the SEM Committee’s duties. This is due to good scoring against a number of criteria delivered through the use of centralised trading arrangements based on the Target Model. It is essential, however, that steps to ensure the mandatory nature are effectively implemented.</p> <p>Further details can be found in Section 5.3 of our response.</p>

8.7 GROSS POOL – NET SETTLEMENT MARKET (SECTION 9)

Question	Answer
<p>16. 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)?</p>	<p>The primary concern with this option is that interconnector flows do not appear fully integrated into the I-SEM and are not based on the I-SEM price vs. the European day-ahead price; however, changes to this market design such as making the day-ahead and intraday trading physical rather than financial, in order to deal with this would lead to a market that would be similar to option (2).</p> <p>Further detail can be found in Section 5.4 of our response.</p>
<p>17. 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)?</p>	<p>Our review against the assessment criteria is broadly in line with the assessment put forward in the Consultation Paper.</p> <p>Further detail can be found in Section 5.4 of our response.</p>
<p>18. 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?</p>	<p>While being compatible with the SEM Committee’s duties in the short term, we consider it has potential shortcomings in the longer term. This is due to good scoring against a number of criteria delivered through the use of centralised trading arrangements based on the existing SEM model, itself derived from eight of the nine assessment criteria. A drawback of this option is its ability to fully integrate with European arrangements both for 2016 and 2021 (NC EB).</p> <p>Further detail can be found in Section 5.4 of our response.</p>

8.8 CAPACITY REMUNERATION MECHANISMS (CHAPTER 10)

Question	Answer
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19. 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?	See Section 6.1
20. Are these the most important topics for describing the high level design of any future CRM for the I-SEM?	The effectiveness of any mechanism depends on the form of energy trading that is in place, the system services remuneration that is in place and also on the detailed design of the option. The characteristics of the various options outlined in Table 10 represent one approach to each option under the various topics. Other approaches exist and we believe that the decision on which option or set of options to proceed with should not lock in detailed designs that have not yet been fully assessed against the energy trading arrangements.

8.9 STRATEGIC RESERVE (CHAPTER 10.7)

Question	Answer
21. 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?)	See section 6.2.1
22. 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)?	We would broadly agree with the RAs' assessment of the Strategic Reserve. See section 6.2.1

23. 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?	The pros and cons of a Strategic Reserve are broadly the same for each of the options for the energy trading arrangements.
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8.10 LONG-TERM PRICE-BASED CRM (CHAPTER 10.9)

Question	Answer
24. 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?)	See section 6.2.2
25. 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)?	There are a number of shortcomings, we believe, associated with price based mechanisms that are not captured in the consultation. We have included these in section 6.2.2 .
26. 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?	It is not possible to identify at this stage if any of the options for energy trading arrangements would be more suited to this approach.

8.11 SHORT-TERM PRICE-BASED CRM (CHAPTER 10.10)

Question	Answer
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27. 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)?	See section 6.2.2
28. 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)?	There are a number of shortcomings, we believe, associated with price based mechanisms that are not captured in the consultation. We have included these in section 6.2.2 .
29. 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?	It is not possible to identify at this stage if any of the options for energy trading arrangements would be more suited to this approach.

8.12 QUANTITY-BASED CAPACITY AUCTION (CHAPTER 10.11)

Question	Answer
30. 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)?	See section 6.2.3.
31. 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	We broadly agree with the initial assessment; however, we would emphasise that the effectiveness of capacity auctions as a capacity mechanism depends on the energy trading option chosen and the detailed design. See section 6.2.3.

<p>suggest (including the strengths and weaknesses of an option relative to the others)?</p>	
<p>32. 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?</p>	<p>In our view, the centralised nature of capacity auctions would be more suited to centralised energy trading arrangements; however, this is more a potential synergy than a requirement. We would recommend that a more detailed assessment of quantity-based options is undertaken with the chosen design for energy trading arrangements to identify the most suitable option. See section 6.2.3.</p>
<p>8.13 QUANTITY-BASED CAPACITY OBLIGATION (CHAPTER 10.12)</p>	
<p>Question</p>	<p>Answer</p>
<p>33. 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)?</p>	<p>See section 6.2.3.</p>
<p>34. 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)?</p>	<p>We broadly agree with the initial assessment; however, we would emphasise that the effectiveness of capacity obligations as a capacity mechanism depends on the energy trading option chosen and the detailed design. See section 6.2.3.</p>
<p>35. 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?</p>	<p>In our view, the decentralised nature of capacity obligations would be more suited to decentralised energy trading arrangements; however, this is more a potential synergy than a requirement. We would recommend that a more detailed assessment of quantity-</p>

based options is undertaken with the chosen design for energy trading arrangements to identify the most suitable option. [See section 6.2.3.](#)

8.14 CENTRALISED RELIABILITY OPTIONS (CHAPTER 10.14)

Question	Answer
36. 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)?	See section 6.2.3.
37. 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)?	The description and assessment of Reliability Options could benefit from more detail. There are a number of attractive features of Reliability Options that are not featured in the consultation. See section 6.2.3.
38. 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?	Reliability Options may not work well with physical forward trading and require spot market prices that reflect the value of scarcity in similar fashion to energy only markets. We would recommend that a more detailed assessment of quantity-based options is undertaken with the chosen design for energy trading arrangements to identify the most suitable option. See section 6.2.3.

8.15 DECENTRALISED RELIABILITY OPTIONS (CHAPTER 10.15)

Question	Answer
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<p>39. 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)?</p>	<p>See section 6.2.3.</p>
<p>40. 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)?</p>	<p>The description and assessment of Reliability Options could benefit from more detail. There are a number of attractive features of Reliability Options that are not featured in the consultation. See section 6.2.3.</p>
<p>41. 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?</p>	<p>Reliability Options may not work well with physical forward trading and require spot market prices that reflect the value of scarcity in similar fashion to energy only markets. We would recommend that a more detailed assessment of quantity-based options is undertaken with the chosen design for energy trading arrangements to identify the most suitable option. See section 6.2.3.</p>