Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Detailed Design

Consultation Paper

SEM-15-044

02 July 2015

EXECUTIVE SUMMARY

The European Union (EU) is building an internal market for electricity and gas, to help deliver energy supplies that are affordable, secure and sustainable. This is underpinned by the implementation of the European Electricity Target Model (EU Target Model) arising from the EU's Third Energy Package. Specifically, the EU Target Model is a set of harmonised arrangements for the cross-border trading of wholesale energy and balancing services across Europe. In this context, the SEM Committee committed to implementing the Integrated Single Electricity Market (I-SEM) that will go-live in Q4 2017, replacing the current Single Electricity Market (SEM) arrangements.

Following extensive consultation over 2014, (including an Impact Assessment) the SEM Committee published the Decision Paper on the High Level Design (HLD) for the I-SEM in keeping with its statutory objectives. Namely, the SEM Committee HLD Decision seeks to maximise benefits for consumers in the short-term and long-term, while ensuring security of supply and meeting environmental requirements.

Subsequently, the Detailed Design Phase of the I-SEM commenced and a number of workstreams were established including the Capacity Remuneration Mechanism (CRM) workstream. In accordance with the procedure and timescales set out in the published project plans, delivery of I-SEM CRM policy will include three consultation and decision papers.

This paper represents the first consultation specifically on the development of the new all-Island CRM. The paper focuses on a number of substantive areas that are fundamental to the CRM design and presents detailed options that respondents can evaluate in a number of key areas. To the extent that any minded to positions exist in relation to these areas, these are set out in this paper. The key policy areas covered in this paper are summarised below.

Capacity Requirement: Determining the appropriate level of capacity that is required to maintain a security standard is pivotal to the success or failure of any CRM.

A key consideration in this section relates to the security standard that should be applied to calculate the amount of capacity required in the I-SEM. A more secure standard will reduce the likelihood of load shedding, however this would come at a greater cost to the all-island consumer. The current security standard for the SEM is 8 hours of Loss of Load Expectation (LoLE) and we have considered whether a 3 hour LoLE standard should be adopted. However, the SEM Committee is not minded to change the security standard from its current level of 8 Hours LOLE. The move to a 3 hour LOLE would increase the requirement for nameplate capacity by 220MW at an estimated cost to consumers of between €14.4 million/year and €19.1 million/year.

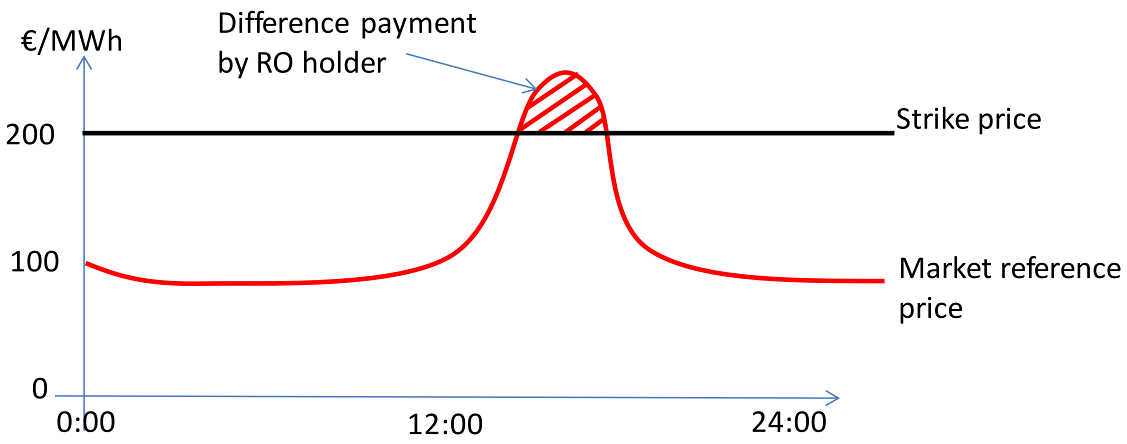
This section also considers the method that will be used to determine how much capacity is required to meet the security standard. Specifically, the paper examines how the CRM will account for unreliability of capacity providers and uncertainty over future levels of demand.

Consideration has also been given to locational pricing. This includes whether zonal auctions and / or locational signals should be included in the CRM design. Given that the Generation Capacity Statement indicates that the North-South interconnector will be in place by 2019 and the I-SEM is expected to continue to be a single energy zone, our minded to position is that we anticipate the capacity requirement and CRM auction will be for a single zone.

Product Design: The I-SEM CRM will take the form of Reliability Options, backed by physical generation. The basic features of a Reliability Option are that it is a one way Contract for Difference, with a Strike Price and a Market Reference Price. The one way Contract for Difference will operate like a financial call option in that:

- The Reliability Option holder (i.e. the capacity provider) bids to receive a basic capacity payment from the Reliability Option Counterparty (i.e. the Transmission System Operators). This capacity payment is analogous to an option fee, and will be determined by the result of a competitive auction
- In all Settlement Periods when the Market Reference Price exceeds the Strike Price, the Reliability Option holder will be required to pay an amount equal to the Market Reference Price minus the Strike Price to the Reliability Option Counterparty, the "difference" payment. This is illustrated below.
- The Reliability Option Counterparty recovers / pays the net difference between option fees paid out and difference payments received from Suppliers.

Difference payments under a Reliability Option



Options to determine the Strike Price and Market Reference Price are presented in this section.

Two choices that could be used to set the strike price for the reliability options are provided, along with indexation provisions. The first approach is to use avoidable (fuel) costs of the actual plant on the system that is likely to have the highest such costs. This would need to be consistent with an assumption that plant will continue to bid its avoidable costs. The second approach is based on using a hypothetical best new entrant peaking unit, as currently used for setting the Annual Capacity Payment Sum in the SEM.

A number of detailed options have been presented that can be used to determine the Market Reference Price. The Market Reference Price is one of the key factors in the design of the CRM product and the performance incentive mechanism. Reliability Options are referenced against a specific near-term or spot market, or a blend of the various markets in which physical energy is traded. These options include the use of the balancing market, the intra-day, day-ahead or a hybrid option as the Market Reference Price.

Along with the various options this section of the paper considers whether administered scarcity pricing should be included (as part of the Balancing Market option) as an additional performance incentive mechanism that may be applied to the standard Reliability Option product.

The use of other additional physical performance incentives in the CRM is also reviewed. In theory, the basic Reliability Option alone provides strong financial incentives to be generating when the options are exercised, since the holder has to pay out the difference between the market price and the option strike price. However experience from other markets with Reliability Options suggests that further incentives could be effective in incentivising physical performance. We discuss performance incentives, drawing on examples from the US and GB, while considering the form of such incentives, caps and floors and performance incentives for renewables and DSUs.

Eligibility: This section considers the criteria that will be used to determine whether a capacity provider is eligible to provide the physical backing for a Reliability Option, and how many Mega Watt (MW) of Reliability Options can be backed by a given MW of "nameplate" capacity.

A key factor considered is the eligibility of plant supported under other mechanisms, such as renewable support, PSO backed peat plant in Ireland and Generating Unit Agreements in Northern Ireland. Options considered include:

- All supported generators ineligible, as in GB
- All existing supported generators who have been eligible for SEM capacity payments eligible, but future generators ineligible.
- All supported generators eligible
- Scheme by scheme specific treatment

Eligibility of demand side participation, Energy Storage, Non-Firm generation is considered in this section. This section also considers whether mandatory participation in the CRM auctions should be introduced, in order to prevent abuse of potential market power. The concern would be that a portfolio generator could withdraw capacity from the auction in order to drive up the market clearing price, and earn a higher capacity payment on the rest of its generation portfolio.

The de-rating of capacity is covered in this section. The amount of capacity which is technically available at any period may be less than the total “nameplate” capacity. This is due to a number of factors such as forced outages. De-rating takes account of the availability of plant, specific to each type of generation technology.

Finally, potential requirements for pre-qualification for existing, refurbished and new plant bidding into the CRM auction is reviewed and considered.

Supplier Arrangements: In this section the basis upon which the cost and payments of the planned CRM are covered. A key consideration is the demand that should be used as the basis for charging. The cost of the CRM will be recovered from Suppliers in proportion to some measure of the demand of their customers. There are two broad options for this measure of demand as follows:

- Flat: The charge is applied equally to all demand as a "per MWh" charge
- Profiled: The charge is focused on demand at times when there is likely to be system stress - and hence a reduced risk of scarcity.

There are a number of options considered for how a profile could be established, including:

- The current SEM Approach - profiled across all hours: costs of capacity are allocated across demand at all times, but at a price which increases for times when incremental demand is likely to increase the need for capacity
- GB (or similar) approach - focused on specific hours: costs are allocated across the demand most likely to increase the need for capacity (e.g. between 4pm and 7pm during November to February).

Institutional Arrangements: This section details plans for the overall institutional framework and governance of the new capacity mechanism. Codified rules will be underpinned through existing or modified licence requirements in both jurisdictions. This section includes roles and responsibilities, capacity market rules and codes, contractual arrangements and implementation agreements.

Next Steps

Interested parties are invited to respond to the consultation, presenting views on the options, proposals and discussion in this paper and where applicable any minded to positions that have been expressed.

The SEM Committee intends to make a decision in October 2015 on the various aspects of the detailed design of the CRM covered in this consultation paper. In reaching this decision we will take into account comments received from respondents to this paper as well as feedback obtained at the public workshops.

A public workshop presenting an overview of this consultation will be held in July 2015 and it is anticipated that a further workshop will be held in advance of the SEM Committee decision in October. Further information on these events will be published at a later date on the All-Island project website.

Responses to the consultation paper should be sent to Brian Mulhern (brian.mulhern@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on 17th August 2015. Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.

Contents

1. INTRODUCTION

1.1 THE DETAILED DESIGN OF THE I-SEM CAPACITY MECHANISM

1.1.1 In the I-SEM High Level Design (HLD) Draft Decision and Final Decision the SEM Committee set out the case for the continuing need for a capacity mechanism in Ireland and Northern Ireland. Energy-only markets may be prone to market failures that make it difficult for such a market to value the reliability of supply to electricity consumers. The SEM Committee took the view that these market failures are acute for a small island system with high penetration of variable renewable generation. The rationale for the capacity mechanism was based on:

- The economic rationale for an explicit capacity remuneration mechanism given the market failures associated with energy only markets, giving rise to the 'missing money problem'.
- Modelling analysis on the impact of the changing system dynamics on the running patterns and hours of conventional generation as a result of the increased penetration of low carbon renewable technologies.
- The magnification of these market failures meaning that the missing money problem is particularly acute in a small island system with high levels of variable generation
- The HLD impact assessment of the need for a capacity remuneration mechanism against the I-SEM primary and secondary assessment criteria.
- Evidence from the Transmission System Operators (TSOs) Generation Adequacy reports (the Generation Capacity Statement and the Adequacy Report for an Energy Only Market)[1]

1.1.2 The SEM Committee ISEM HLD Decision sets out the design of the CRM at conceptual level. The Final HLD Decision as published in mid-September 2014 provides that the I-SEM CRM will take the form of centralised Reliability Options (RO), centrally auctioned by the TSOs and centrally settled. It further states that there will be a requirement for physical backup (firm energy) for providers to be eligible to participate in the CRM auction, in line with international best practice in implementing CRMs and stakeholder feedback.

1.1.3 Reliability Options consist of contract holders receiving capacity payments in the form of an option fee, in exchange for which they face exposure to difference payments in the event that a Market Reference Price (MRP) exceeds the Strike Price (SP). The seller of the capacity is incentivised to deliver energy into the reference market when

[1]For more on the I-SEM HLD CRM Decision see:
http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f

capacity margins are tight which is reflected in the MRP rising to reflect such scarcity conditions.

1.1.4 This paper, the first CRM Detailed Design Consultation Paper sets out options for key aspects of the CRM design most notable the product and performance incentives and eligibility requirements.

1.2 CAPACITY MECHANISM DESIGN IN CONTEXT

Capacity Mechanism Design – the Wider Context

1.2.1 Capacity Mechanisms and their design are an increasingly important element of electricity markets across the world, notably in North and South America and more recently in Europe. In a number of US States, capacity markets were included in the original market design, however they are new features of some European electricity markets driven in part by the increasing penetration of renewable generation and the impact of this on system reliability.

1.2.2 Some of the capacity mechanisms in the United States have recently undergone fundamental change, most notably the Forward Capacity Market run by the Independent System Operator New England (NE ISO). A greater emphasis has been placed in these markets on performance incentives and ensuring that consumers receive value for money through incentivising generation to be available and deliver energy when the electricity system requires it in the short term[2]. There is also increasing attention in the literature on capacity market designs and debate is focussing on the strength of performance incentives as a long run signal for efficient investment[3].

Capacity Mechanisms in Europe – Cross Border Trade and Internal Market Rules

1.2.3 The landscape for energy market design in Europe is changing to in some cases accommodate capacity mechanisms (such as the new CRMs in Great Britain and France and the implementation of revised capacity markets based on RO in

[2] Recent endorsement by the Federal Energy Regulatory Commission of the revised NE ISO Forward Capacity market rules, the so called 'Pay for Performance Scheme' would indicate that this design will be an increasingly dominant feature of the standard market design in the United States. See: http://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

[3] This topic was presented by Peter Cramton, Professor of Economics at the University of Maryland, at the RAs' workshop on the Capacity Mechanism Detailed Design in Dundalk on 8 May 2015.
For more see:
http://www.cramton.umd.edu/papers2015-2019/cramton-market-design-in-energy-and-communications.pdf
and
http://www.iit.upcomillas.es/batlle/Publications/2015%20Capacity%20mechanisms%20and%20performance%20incentives%20_%20Mastropietro%20et%20al.pdf

Ireland/Northern Ireland and Italy) to address increasing concerns in some Member States about security of electricity supply and cross border trade. A further concern relates to the European Target Model not being distorted or compromised by national or regional capacity mechanisms.

1.2.4 European regulators, through the Agency for Cooperation of Energy Regulators (ACER) are working to ensure that if CRMs are introduced they are designed so as not distort the internal market. ACER is expected to publish a report on this issue later in 2015. In addition Eurelectric, the umbrella group for the European electricity industry have recently published a position paper on how to coordinate different Capacity Mechanism designs in the context of the internal market as has the European Network of Transmission System Operators – Electricity (ENTSO-E), the TSOs European representative body[4].

1.2.5 The European Commission (EC) is concerned that uncoordinated introduction of capacity mechanisms have the potential to distort cross border trade in the European Union (EU) and hamper competition between capacity providers. To ensure that this doesn't happen the EC included provisions in its revised Environmental and Energy State Aid Guidelines (EEAG)in July 2014 that require capacity mechanisms to adhere to a set of criteria before their introduction[5]. In addition, the EC's Directorate General for Competition has also recently launched a Sector Enquiry into the existence and functioning of capacity mechanisms in order to gather information on existing and planned capacity mechanisms and generation adequacy assessments that underpin these. The Sector Enquiry was addressed to a number of Member States including Ireland and the Department of Communications, Energy and Natural Resources (DCENR), Commission for Energy Regulation (CER) and EirGrid have provided submissions to the EC. It is our understanding that, as well as public authorities, the EC also elicited responses to the enquiry from some market participants in Ireland. The Enquiry has now also been expanded to include Northern Ireland so that the EC can get a comprehensive view of generation adequacy in the SEM.

1.2.6 The EC plans to publish the preliminary findings from the CRM Sector Enquiry for public consultation before adopting a final report in the course of 2016. We understand that the EC intend to consult on how the European electricity market should evolve to address the challenges of increasing renewables, including capacity mechanisms with emphasis on building on the foundations laid by the Target Model and the EEAG

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[4] See: http://www.eurelectric.org/media/115058/eurelectric_background_note_crm_c-b_participation_09122013_final-2013-2200-0002-01-e.pdf and https://www.entsoe.eu/news-events/announcements/announcements-archive/Pages/News/Policy-Paper-Capacity-Mechanisms.aspx

[5] See: http://ec.europa.eu/competition/sectors/energy/legislation_en.html

1.2.7 The SEM Committee and the Regulatory Authorities (RAs), in close cooperation with the Departments (DCENR and the Department of Enterprise, Trade and Investment (DETI)) are engaging with the EC on the design of the I-SEM Capacity Mechanism, to ensure that the detailed design complies with existing and emerging European rules and guidelines.

1.3 STAKEHOLDER ENGAGEMENT

1.3.1 The stakeholder engagement approach for the detailed design stage involves engaging with a broad range of stakeholders including generators, investors, demand side units, supply companies, large energy users and the TSOs.

1.3.2 The RAs have engaged in an extensive period of stakeholder engagement since the HLD. This engagement has helped the RAs in developing an understanding of the key issues that will be faced in this workstream along with potential options for dealing with many of these issues. This engagement has involved the following:

Bilateral Meetings and stakeholder workshop with Industry

1.3.3 We held 28 Industry Bilateral Meetings on the CRM design in December 2014. This included meetings with generators, potential new investors, demand side units, supply companies and large energy users. These meetings provided each party with an opportunity to highlight their key concerns and interests and proved useful in helping the project team understand the potential issues and questions that will need to be dealt with as part of our consultation process as set out in this paper.

1.3.4 The RAs also hosted a Stakeholder workshop on the CRM on 8 May 2015 in Dundalk please see link to presentations here.

TSO engagement on implementation

1.3.5 The RAs have had ongoing engagement with the TSOs in relation to the implementation of different aspects of the CRM in order to ensure the successful delivery of the project from a systems perspective as well as specific TSO related functions such as a the setting of the capacity requirement. It is envisaged that this close working relationship will continue to inform the development of the CRM along with wider industry engagement.

European Commission (EC)

1.3.6 We have had extensive engagement with the EC on the design of the CRM and State Aid Notification process. This includes attendance and input into a series of workshops on the design of the CRM covering product, obligations, eligibility and competitive bidding processes. This engagement is informing our design and assessment of the CRM to ensure it is compatible with EU rules and guidelines.

Department of Energy and Climate Change (DECC) and Ofgem

1.3.7 The RAs have been and will continue to liaise with DECC and Ofgem on cross border issues. Discussions about DECCs recent experience of implementation of the CRM in Great Britain have been helpful in this process. We plan to engage with National Grid (NG) on cross border participation in the CRM as part of Consultation Paper 2.

Future Stakeholder Engagement

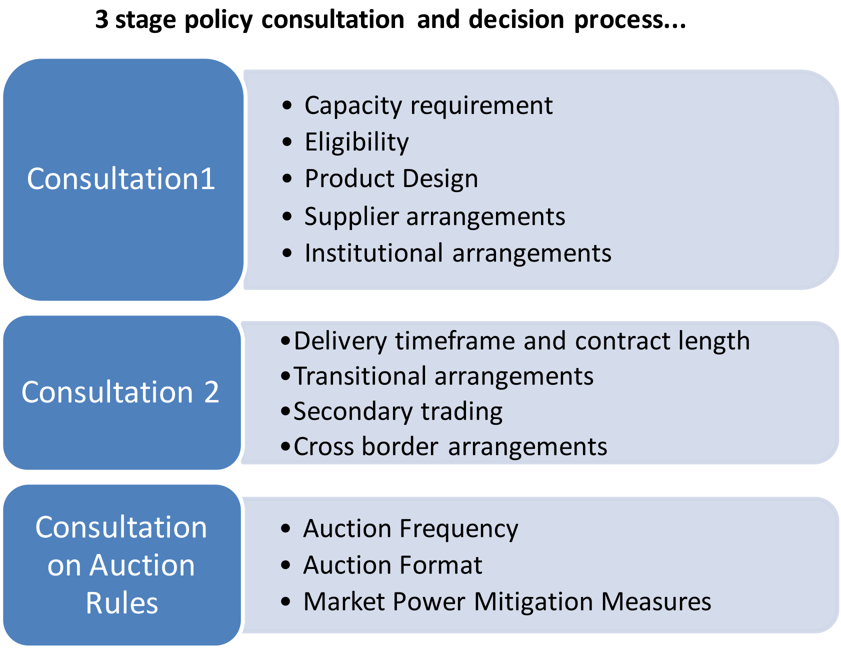
1.3.8 The RAs will carry out the following stakeholder engagement over the coming months:

- Workshop 1B - July 2015 (present Consultation 1)
- Workshop 1C – September 2015 (pre Decision 1)
- Publish Decision 1 – November 2015
- Workshop 2A – September / October 2015 (pre Consultation 2)
- Publish Consultation 2 – November 2015

1.4 PROCESS AND STRUCTURE OF THIS PAPER

1.4.1 The purpose of the CRM Detailed Design is to develop through consultation the specific design features of the new capacity mechanism. As illustrated in Figure 1-1, this consultation paper is the first of three stages of consultation in the development of the CRM Detailed Design.

Figure 1-1 : Overview of CRM Policy Development



1.4.2 In addition to the above policy designs we will be working with TSOs in relation to systemisation and codification of the mechanism; and will be working with DCENR and DETI in relation to State Aid notification. It will also be important to ensure that there is alignment between CRM development, other ISEM workstreams and DS3[6] to ensure customers are protected and investors are appropriately incentivised.

1.4.3 The key issues discussed in this first consultation paper are:

- **Capacity Requirement** (in conjunction with the TSOs). Section 2 considers whether the security standard underpinning the amount of capacity to be procured should be changed from the existing standard of 8 hours Loss of Load Expectation to 3 hours. This section also discusses other methodological issues informing the calculation of capacity to be procured; the treatment of non-contracting plant[7] in determining the capacity requirement, and locational issues. Accompanying this is a TSO technical paper on the all-island security standard.
- **Product Design**. Section 3 covers a number of aspects of the product design including:
  - The Strike Price
  - The Reference Market / Reference Market Price; and
  - Additional performance incentives.

[6] Further information on the DS3 project is available on the All Island Project website: http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=332ac31a-1224-44c7-97b6-00a7b6c8a8b9

[7] Including any capacity which is not eligible to compete in the CRM, or any capacity which is eligible to compete but chooses not to, if it is not mandatory for all relevant capacity to bid into the CRM

In discussing these design features, the section reviews experience and best practice from other relevant markets.

- **Eligibility Rules**. Section 4 discusses which type of plant should be eligible to compete in the I-SEM CRM, and how different plant may need to be de-rated to appropriately reflect their contribution to meeting the capacity requirement. Types of plant considered include:
    - Plant receiving support under specific mechanisms that provide financial support, such as renewables support, PSO backed peat plant in Ireland and Generating Unit Agreements (GUAs) in Northern Ireland
    - Other renewables participation
    - Demand Side Participation
    - Energy storage
    - Non-firm generation- plant without firm access to the transmission network
    - Aggregators and Power Purchase Agreement (PPA) providers
- **Supplier Arrangements**. Section 5 reflects on the current arrangements for recovering capacity costs from Suppliers and proceeds to discuss alternative options and the need for changing the current cost recovery approach. Credit cover (i.e. collateral) requirements, including generator credit cover is discussed, as is the treatment of exchange rate risk which will be more significant in the I-SEM CRM, given the potential for longer term capacity contracts.
- **Institutional Arrangements.** Section 6 sets out the proposed governance arrangements for the CRM, which we envisage consisting of a suite of revised and new rules which set out the detailed provisions for registration, participation, pricing, settlement of capacity payments and rules for participation in the capacity auctions and rights and obligations arising out of those auctions. These detailed, codified rules will be underpinned as appropriate through existing or modified licences requirements in both jurisdictions. These rules will ultimately be overseen and approved by the SEM Committee.
- Sections 7 and 8 set out the **Next Steps** and a list of **Acronyms**

1.5 CRITERIA FOR ASSESSING

1.5.1 The assessment criteria for the detailed design of the CRM are based on the same principles as those applied to the I-SEM High Level Design and as agreed with the Departments in the Next Steps Decision Paper March 2013. We have developed detailed descriptions of these criteria to focus on issues that are relevant to procuring capacity and tailored to the detailed design elements of the capacity remuneration mechanism.

1.5.2 These assessment criteria are set out below:

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

1.5.3 A successful capacity market will provide security of supply and a reliable power system at least cost over the long term, by ensuring an efficient mix of resources and efficient short term dispatch that reduces market risk and mitigates market power. In designing and implementing the I-SEM Capacity Mechanism, we will seek to address any potential distortion to the European Internal Market and retain efficient cross border trade.

1.5.4 In assessing the various options under the different sections we acknowledge that there are trade-offs to be struck between the different assessment criteria. For example, strong performance incentives may deliver security of supply and a reliable power system but may be more difficult to apply to cross border capacity and could mean market entry is more challenging. Similarly, practicality of implementation will need to be balanced against ensuring that the mechanism incentivises providers to contribute to a reliable power system and competition and investment signal should be balanced with the requirement for the mechanism to adapt to changing circumstances.

1.6 GOVERNANCE AND IMPLEMENTATION

1.6.1 The SEM Committee published a consultation paper on 6 March 2015 setting out the proposed institutional arrangements and key roles and responsibilities for the establishment and operation of the I-SEM. As set out in the Roles and Responsibilities Paper, the overall governance for the I-SEM will be based on overarching European regulations and guidelines and legislation in Ireland and Northern Ireland. Proposed legislative changes for I-SEM are currently being consulted on by DETI[8] and DCENR[9].

1.6.2 As set out in Section 6, we intend the new arrangements for the capacity mechanism to be implemented through market codes which set out the detailed rules for registration, participation, pricing, and settlement of capacity payments and charges. These rules will be ultimately overseen and approved by the SEM Committee. These detailed, codified rules will be underpinned as appropriate through existing or modified licences requirements in both jurisdictions.

1.6.3 Furthermore, we consider that detailed rules will need to be developed for the remuneration of capacity providers that have been successful in the capacity auctions and the concomitant rules for capacity charges on suppliers. We set out in this paper options for contractual arrangements for the CRM including a revised trading and settlement code and capacity market rules that will set out the rules and procedures for participation in and prequalification for the capacity auctions as well as provisions for capacity agreements or other forms of counterparty arrangements that set out the obligations and rights of market participants who have been successful in the capacity auctions. We intend to consider contractual arrangements including the counterparty model and contract duration in more detail in Consultation Paper 2.

[8] http://www.detini.gov.uk/index/deti-consultations/consultation_exercises/electricity__single_wholesale_market___northern_ireland__order_2007_.htm

[9] http://www.dcenr.gov.ie/Energy/Electricity+and+Gas+Regulation/I-SEM.htm

2. CAPACITY REQUIREMENT

2.1 INTRODUCTION

2.1.1 Determining the appropriate level of capacity that is required to maintain the security standard is pivotal to the success or failure of any CRM. EU requirements for state aid declare that this must be done in a manner consistent with ENTSO-E guidelines[10]. These are currently evolving, but through our engagement with ENTSO-E / TSOs the expectation is that the quantity of capacity required will focus on a defined "generation" security standard.

2.1.2 This section focuses on the aspects informing the determination of the volume of capacity to be procured and poses the following consultation questions. :

- **Security Standard:** Should the existing security standard of 8 hours be retained or should we move to a new security standard of 3 hours or other standard?
- **Method:** Which of the options do you consider most appropriate for determining the quantity of capacity required to meet a specified security standard?

2.2 SECURITY STANDARD

2.2.1 As defined by ENTSO-E,[11] generation adequacy of a power system is "an assessment of the ability of the generation on the power system to match the consumption on the same power system". In practice, a defined level of adequacy (or security standard) requires that the level of installed generation capacity is higher than the level of consumption at all times. This additional margin of spare generation capacity is required for when other generators break down (have a forced outage).

2.2.2 Across the EU there are currently numerous generation standard parameters to assess generation adequacy.

2.2.3 The All-Island power system is currently managed against a generation security standard expressed as a Loss of Load Expectation (LoLE). This LoLE is a modelled estimate of the number of hours in an average year where there will be insufficient generation to cover demand. At present, the generation security standard is evaluated for the SEM as a whole, as well as separately for Ireland and Northern Ireland, using the following security standards:

[10]Our assessment of these guidelines is based on "ENTSO-E Target Methodology for Adequacy Assessment, 14 October 2014" and "Scenario Outlook and Adequacy Forecast Evolutions", ENTSO-E, 14 October 2014

[11] ENTSO-E Report, "System Adequacy Forecast 2010 - 2025", 2010

- SEM: 8 hours LOLE
- Ireland: 8 hours LOLE
- Northern Ireland : 4.9 hours LOLE

2.2.4 For the Member States using the LOLE standard, the 8 hour LOLE represents a relatively high expectation of unserved load. GB and France use a 3 hour standard, with the Netherlands using a 4 hour standard. Applying a similar standard in the I-SEM to that used in neighbouring markets would bring an apparent consistency and therefore harmonisation of capacity markets across Europe; however, the relative costs of equivalent security standards are higher for small island systems than for large interconnected continental systems. The level of reserve margin (as a percentage of peak demand) required to secure a system falls with the number of generators on the system - as they are not all likely to break down at the same time. A small island system would then need a greater reserve margin than a larger system to achieve an equivalent LOLE, at a higher cost per customer.

2.2.5 To inform consideration of this issue, we have requested that the TSOs have carried out analysis of the implications of moving to a secure standard based on a 3 hour LoLE. This is included in Appendix A.

2.2.6 The TSO Analysis estimates the cost of providing new capacity to reduce the LOLE, priced at both the proposed Best New Entrant (BNE) price for 2016 (€65.50/kW year) and the highest BNE price used in the history of the SEM (€87/kW year)

Minded to position

2.2.7 Having considered the TSO's analysis, the SEM Committee is not minded to change the security standard from its current level of 8 Hours LOLE. The move to a 3 hour LOLE would increase the requirement for nameplate capacity by 220MW at a cost to consumers of between €14.4 million/year and €19.1 million/year, depending on which value of the BNE price is used. This cost to consumers is offset by a more theoretical and modelled benefit based on an assumed reduction in the occurrence of unserved load. This estimate is, itself subject to uncertainty, notably:

- Recent analysis of the LOLE security standard for GB suggests that, in fact, much of the unserved load indicated by LOLE analysis would be managed without a significant impact on consumers[12]; and
- The estimate of unserved load is converted into a cost using an assumed Value of Lost Load (VoLL) for the SEM. This value of VoLL is not based on analysis of the value customers actually place on not being disconnected. The VoLL has

[12] Paragraph 3 ii, Annex C to "Consultation of the Draft Electricity Market Reform Delivery Plan", GB Department of Energy and Climate Change, July 2013

been estimated based on the average costs of the last plant needed to maintain an 8 hour LOLE.

2.2.8 We welcome consultation responses on this point.

2.3 METHOD

2.3.1 An analytic method is required to determine how much capacity is required to meet a defined security standard. Relevant EU guidelines for state aid require this to be done in a manner that is consistent with ENTSO-E guidelines[13], which include:

- Specific guidelines to calculate the base data for the analysis of capacity adequacy;
- A requirement for the scenario building process to be transparent and publicly consulted on with stakeholders;
- An expectation that the harmonised approach will evolve over time, including:
  - Requirements for a probabilistic assessment of renewable output and of the temperature sensitivity of load;
  - Improvements to the modelling of cross border exchanges.

2.3.2 The ENTSO-E requirements also state that an assessment of generation adequacy[14] should be carried out every two years.

2.3.3 The approach currently applied for the All-Island Generation Capacity Statement[15] is in line with the ENTSO-E approach but is carried out on an annual basis.

2.3.4 The approach used by TSOs to determine the capacity requirement for the I-SEM will be to build on the current and ENTSO-E approach; we will however review it and seek to ensure that it incentivises the most efficient solution in the context of the I-SEM CRM. The key issues to consider are:

- How the CRM accounts for unreliability of capacity providers; and
- How the CRM accounts for uncertainty over the future level of demand; and
- How are interconnectors treated

[13] This assessment of these guidelines is based on "ENTSO-E Target Methodology for Adequacy Assessment, 14 October 2014" and "Scenario Outlook and Adequacy Forecast Evolutions", ENTSO-E, 14 October 2014

[14] EC Regulation 714/2009 requires TSOs to build "national generation adequacy outlooks" that are used by ENTSOE as the basis of a "European generation adequacy outlook"

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

Accounting for plant unreliability

2.3.5 All potential providers of capacity will have an element of un-reliability, meaning there are times they will be unable to perform, for example from forced outages or from intermittency. This unreliability is traditionally measured as the Forced Outage Rate (FOR) for a given plant or plant type. In its simplest form, the FOR is the percentage of time that the plant is unable to perform as planned.

2.3.6 Forced outages drive the need for a margin of spare capacity (over and above peak demand) to replace that which is unable to perform. The size of this margin will increase with the tightness of the security standard i.e. a 3 hour LoLE would require a greater margin than an 8 hour LoLE.

2.3.7 There are two options for how unreliability can be accommodated within the calculation of the capacity requirement for the CRM:

- **Total Requirement:** This approach would determine the total "nameplate" capacity required to meet the specified security standard. This will result in a capacity requirement that may be higher than forecast demand, with the margin of additional capacity being required to cover the risks arising from the reliability of plant. This approach would be similar to that currently used by the TSOs to determine the capacity requirement for the SEM[16].

- **De-rated Requirement:** Under a de-rated approach, capacity providers will only be eligible for capacity contracts up to a defined fraction of their nameplate capacity. The defined fraction would vary by capacity type - reflecting its typical reliability, and hence its impact on the total nameplate requirement for capacity. This approach has been used in the GB market.

2.3.8 Our assessment of the above options has us conclude that the "De-Rated Requirement" approach is more appropriate for the following reasons:-

- Should capacity providers offer their full name-plate capacity into the auction, the capacity auction risks being distorted in favour of un-reliable plant, that are more likely to be unable to provide their full name-plate capacity.
- The total amount of name-plate capacity required is very sensitive to the mix of capacity on the system. An increment of wind capacity that displaces a thermal plant could significantly increase the requirement for nameplate capacity; however, the auction requirement may already have been set.

[16] The methodology for the determination of the SEM Capacity Requirement is set out in SEM-07-13. http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=64eb1095-92de-4ae2-a053-19a3cfc2307b

Accounting for demand forecast uncertainty

2.3.9 The quantity of capacity that is required to meet a defined security standard for a given year will depend on the level of demand in that year. The nature of the proposed CRM is that capacity is procured a number of years ahead of its anticipated need - allowing time for new capacity to be built. As such, the capacity requirement in any year is based on a forecast of demand in that year.

Demand forecasts are never 100% accurate for the following reasons:-

- Estimate errors in factors that drive demand growth (e.g. GDP growth)
- The relationship between the drivers of demand (e.g., consumer behaviour) and the level of demand are not static over time. Forecasting approaches generally take time to catch up with changes in consumer behaviour
- Output of intermittent plant is weather dependent and unpredictable, with impacts for the total level of capacity required as well as for the level of "non-intermittent" capacity.
- Electricity demand is weather dependant - and can change significantly between "cold" and "warm" years.

2.3.10 EU / ENTSO-E requirements imply a need to consider this uncertainty in demand forecasting, their guidelines imply that a number of scenarios should be used to inform future forecast levels of demand. There are a number of options for how the uncertainty around the demand forecast can be assessed for the I-SEM CRM, as set out below:-

- **Single average scenario:** The requirement for multiple scenarios notwithstanding, this approach is likely to deliver a Capacity Requirement that will, on average be less than that required to meet the defined (8 hour LoLE) security standard. This arises from the nature of the LoLE function - meaning that LoLE will rise faster as demand increases than it falls as demand decreases.
- **Worst case scenario:** It would be possible to determine the Capacity Requirement based on a "worst case" scenario, for example based on a 1 in 20 "bad" winter, leading to a high demand.
- **Select an optimal scenario:** This approach determines the capacity requirement under a number of scenarios, and then selects the "optimal" scenario based on a defined rule. This is the approach used by the GB capacity mechanism, where the rule to select the optimal scenario is based on that which minimises the "regret cost" as follows:
    - If demand forecast is too high, the regret cost relates to buying too much capacity. This is estimated as the product of the estimated (per MW

year) cost of capacity, and the capacity increment for that scenario relative to a base scenario.
  - If demand forecast is too low, the regret cost relates to a higher LoLE. The increase in LoLE is determined by evaluating the LoLE based on the assumed demand in a base scenario, with the level of installed capacity consistent with the scenario being evaluated. The "regret cost" is the product of the Value of Lost Load (VoLL) and the increase in LoLE.
  - Each scenarios regret cost is determined with respect to each of the alternative scenarios
  - The scenario selected is that with the least worst regret costs.
- **Stochastic modelling:** It is possible to envisage a stochastic approach that stochastically models the key factors that drive a need for capacity, and then more accurately determine the level of capacity required to meet a defined LOLE. This would probably go beyond any of the approaches currently used within Europe for the assessment of Capacity Adequacy. Whilst such approaches are not used at present, The I-SEM may need to adopt them if and when they emerge.

How are Interconnectors treated?

2.3.11 The quantity of capacity to be procured from providers physically located in the I-SEM will depend on:

- The extent to which I-SEM demand will be satisfied by imports from the GB price zone (based on assumptions of the relative energy prices in GB and I-SEM); and
- The extent to which capacity located in the I-SEM will need to increase to support exports to GB. This, in turn, depends on the treatment of interconnectors within the I-SEM CRM and the GB Capacity Market. This will be considered further as part of the second consultation paper relating to the I-SEM CRM.

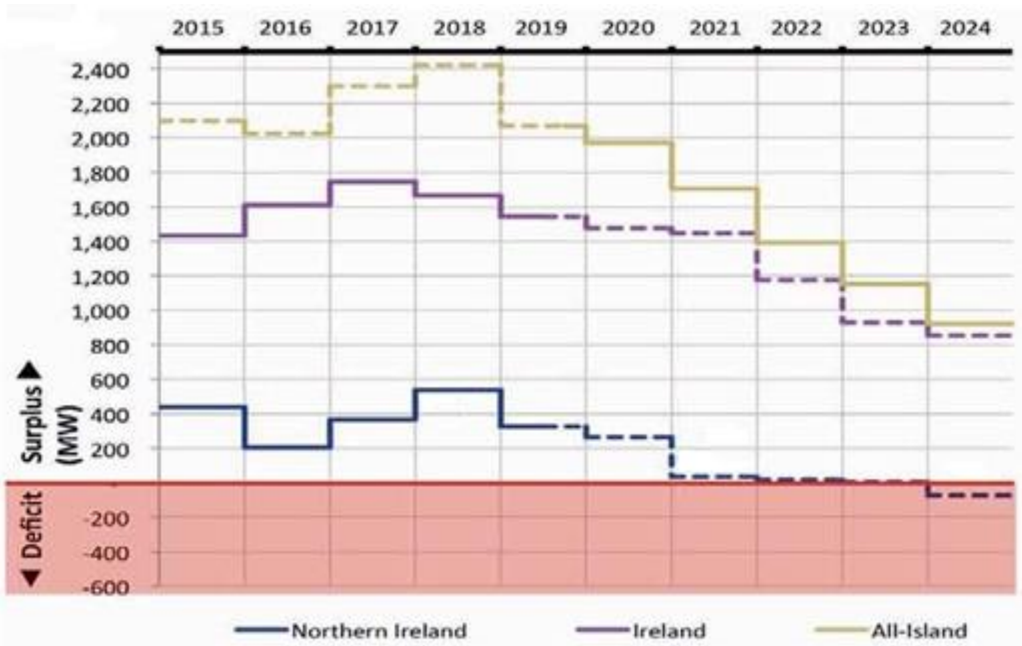
2.4 ADJUSTING THE CAPACITY REQUIREMENT

2.4.1 As well as determining the total (name plate or de-rated) capacity that is required to meet a specified security standard, there is also a need to determine how much of that will be procured through each specific auction. This may be less than the full capacity requirement for a number of reasons, including that some capacity may be ineligible to participate in the CRM, or if it is eligible, it may choose not to participate, assuming it is not mandatory for eligible capacity to participate. Eligibility and mandatory versus compulsory CRM participation are discussed further in Section 4.

2.5 LOCATION

2.5.1 In practice, the system is not indifferent to the location of capacity that is procured. The value of capacity may vary by location, reflecting transmission constraints (or the cost to resolve those constraints), as well as transmission losses. A tangible example of this locational issue arises if the planned new North - South Interconnector is delayed. The current TSO generation adequacy statement shows that a significant delay could lead to a local need for new capacity in Northern Ireland over the coming years. This is shown in Figure 2-1 below.

Figure 2-1: Projected Capacity Margin, from All Island Generation Capacity Statement, 2015 to 2024



2.5.2 The above chart shows the level of capacity surplus over the level needed to deliver the required security standard for the SEM as a whole, as well as for the respective systems of Northern Ireland and in Ireland on an individual basis. Until delivery of the proposed North - South interconnector, the adequacy assessment[17] is considered on a jurisdictional basis (purple and blue solid lines). The North - South interconnector is currently forecast for delivery in 2019 at which time the assessment can be considered on an all-island basis (yellow solid line).

2.5.3 The SEM is a single energy zone and capacity market and the working assumption is that the I-SEM will continue to be a single zone energy market (subject to the bidding zone review process under the Capacity Allocation and Congestion Management

[17] A generation adequacy assessment is a method of representing the likelihood of there being sufficient generation to meet customer demand against a defined security standard. Further information is available from the All Island Generation Capacity Statements available at http://www.eirgrid.com/aboutus/publications/.

(CACM) Regulation). Locational signals for the provision of electricity in the current SEM include the use of Transmission Loss Adjustment Factors (TLAFs) and Generator Transmission Use of System charges (GTUoS). These signals are considered outside the scope of this consultation.

2.5.4 However, we considered a number of options to deal with locational signals for capacity. These are summarised below:

- **Auction for a single zone:** This is consistent with the current arrangements whereby there is a single zone in both the capacity and energy markets. This option would be the simplest to implement, and will help mitigate issues in relation to market power and therefore facilitates a more competitive outcome.
- **Auctions for multiple zones:** This option splits the capacity market into two or more sub-markets (similar to the ISO NE capacity market and that in Italy), by introducing a locational constraint into the auction leading to zonal capacity prices. Whilst this approach has the ability to ensure an acceptable locational capacity mix, it would be more complicated to implement, particularly in the context of a single energy zone. The sub-markets will, by definition, be smaller than the entire market for capacity. This smaller market size will compound any issues of market power.
- **Locational Price Adjustment:** This option can be combined with auctions for either single or multiple zones. It adjusts the price of individual capacity bids to reflect the consequential costs (e.g. network reinforcement) of choosing one capacity provider over another. Capacity providers that are successful in the auction are then paid the auction clearing price less the adjustment to its bid. A method to deliver this price adjustment is likely to be complicated to deliver and challenging to implement for I-SEM go-live.

Minded to position

2.5.5 Considering that the TSO Generation Capacity Statement indicates that the North-South interconnector will be in place by 2019 and the I-SEM is expected to continue to be a single energy zone, **the capacity requirement and CRM auction will be for a single zone**. A single I-SEM wide capacity requirement will be estimated annually, as the basis for the CRM auction.

2.5.6 We have also considered introducing a further locational signal through CRM price adjustments. However, we note that this introduces a level of complexity which would be challenging to achieve within the current I-SEM programme. In this context we may separately consider a review of GTUoS charging to provide improved signals for location of generation.

2.6 SUMMARY OF QUESTIONS:

2.6.1 The SEM Committee welcomes views on all aspects of this section, including:

A) Feedback on our minded to position to retain the all-island security standard of 8 hours LoLE.

B) Comments from respondents as to their preferred method of accounting for unreliability of capacity in determining the capacity requirement, along with reasons behind their preference.

C) Feedback on the options presented in relation to accounting for demand forecast uncertainty, along with rationale behind any position.

D) Feedback on our minded to position to base the capacity requirement for the CRM on a single capacity zone

E) Detail of any other considerations respondents felt that we should take account of when determining the capacity requirement for the CRM.

3. PRODUCT DESIGN

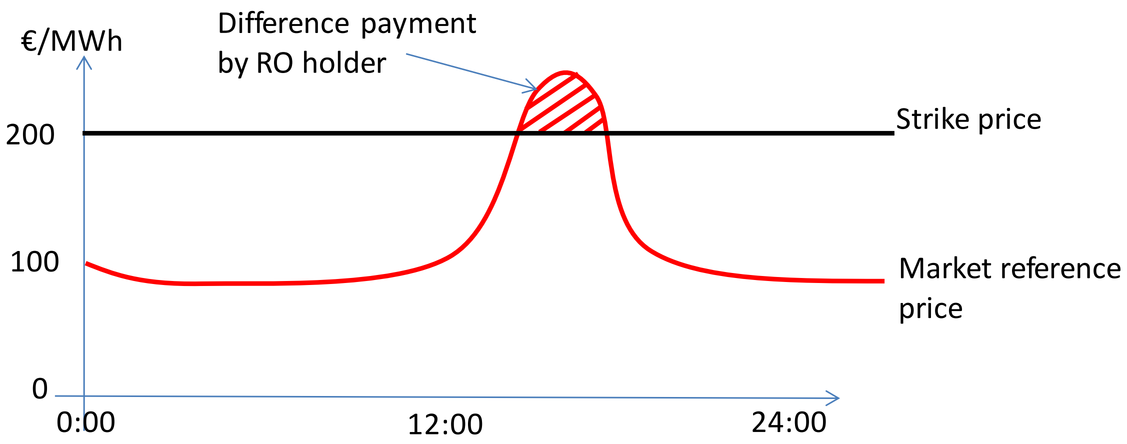
3.1 INTRODUCTION

3.1.1 The I-SEM Capacity Remuneration Mechanism (CRM) will take the form of Reliability Options (ROs), backed by physical generation.

3.1.2 The basic features of the RO product are that:

- It is a one-way Contract for Difference (CfD), with a Strike Price (SP) and a Market Reference Price (MRP);
- The one-way CfD operates like a financial call option:
  - The RO holder (i.e. the capacity provider) bids to receive a basic capacity payment from the RO Counterparty (i.e. the TSOs). This capacity payment is analogous to an option fee, and will be determined by the result of a competitive auction;
  - In all settlement periods when the MRP exceeds the Strike Price, the RO holder will be required to pay an amount equal to the MRP minus the Strike Price to the RO Counterparty, the "difference" payment, as illustrated in Figure 3-1. The RO Counterparty recovers / pays[18] the net difference between option fees paid out and difference payments received from Suppliers.

Figure 3-1: Difference payments under a Reliability Option (RO)



3.1.3 A basic worked example of the payments flows under a RO is as follows:

[18] In periods of high system stress, it is conceivable that difference payments could exceed option fees, so there may be a rebate to Suppliers, depending on the design of the product. However, if there is missing money, on average the amount paid out in option fees may exceed difference payments.

- Suppose that the capacity auction for a particular delivery year yields a capacity price (i.e. option fee) of €20/kW per annum, which equates to €2.28/MWh[19]. The RO holder received this option for each hour of the delivery period, regardless of whether any plant backing the option is on planned or forced outage. Thus it earns a net revenue of €2.28/MWh in any settlement period when the Market Reference Price is less than or equal to the Strike Price.
- Let us assume that in one settlement period, the Strike Price is €200/MWh and the market reference price is €300/MWh. In that period, the RO holder has to pay a difference payment of €100/MWh so that its net CRM revenue is -€97.72/MWh for that trading period. However, if the RO holder has backed its RO with physical capacity which has been sold into the reference energy market, it will have earned €300/MWh from the energy market and so its combined net revenue from the energy and capacity market will be € (300 - 97.72) = €202.28/MWh, i.e. its net revenue from both markets is equal to the RO strike price plus the capacity fee.

3.1.4 In the above example, the €100/MWh difference payment (i.e. the difference between the €300/MWh reference price and the €200/MWh Strike Price) is paid to Suppliers, and provides Suppliers with a hedge against spot price spikes. This means that any hedging products traded in the energy market, such as the existing Directed and Non-Directed two-way CfDs would need to be re-designed to dis-apply above the Strike Price, to ensure generators and Suppliers are not over-hedged. Thus, if Generator X and Supplier Y had struck a two-way CfD at €80/MWh, in the above example, the two-way CfD would need to be re-designed so that it paid out up to €200/MWh RO Strike Price, and the RO paid out any amounts above the RO Strike Price. Therefore in this case, under the two-way CfD, Generator X would pay Supplier Y €120/MWh (€200-80). Supplier Y would pay €300/MWh in the reference market for the physical power, but would receive €100/MWh back via the RO and €120/MWh back via the two-way CfD, and hence pay a net amount of €80/MWh. Assuming Generator X was an RO holder, it would have received €300/MWh for the energy sold in the reference market, but pay out €120/MWh on the two-way CfD and €100/MWh on the RO volume, leaving Generator X with a net revenue of €80/MWh.

3.1.5 In the development of the I-SEM HLD, the SEM Committee concluded that the ROs in the I-SEM should include a requirement for ROs to be backed by physical capacity, which means that ROs will not be purely financial options. This is the approach taken in forward capacity markets operating in the United States, notably in New England (ISO NE) and Pennsylvania – Jersey - Maryland (PJM) markets. The HLD design also stated that it may be appropriate to place additional performance incentives on capacity providers to ensure they deliver capacity at times when it is most needed.

[19] €20/kW per annum =€20,000 /MW per annum = €20,000 / (365 x 24) = €2.28 per MW per hour

This would build on international best practice in this area including recent modifications to strengthen performance incentives in the ISO NE and PJM markets. It would also reflect the direction of travel in capacity market design in Europe and the requirement of the ECs EEAG regarding generation adequacy which require that:

3.1.6 *'Environmental and energy aid can only be found compatible with the internal market if it has an incentive effect. An incentive effect occurs when the aid induces the beneficiary to change its behaviour…to improve the functioning of a secure, affordable and sustainable energy market' (Article 49)*

3.1.7 This section considers the product design of the CRM and the associated obligations and incentive mechanism, in particular:

- Discussion on the options to set the Strike Price for the ROs
- Potential implementation of administered scarcity pricing in the balancing market and the degree of price coverage offered by the RO
- Options for the Market Reference Price for the ROs
- The load following nature of the RO obligation;
- The Performance Incentive Mechanisms

3.2 STRIKE PRICE

3.2.1 The Strike Price in the RO is the price at which the TSOs can exercise the call options of all providers of RO options in the I-SEM. Within the CRM there will be a strong inter-relationship between Strike Price (SP), the MRP and the incentive regime. A number of key SP design issues that will need to be determined will include:

- How to determine the I-SEM CRM strike price; and
- Indexation provisions;

3.2.2 In general, the SP should be set sufficiently high that difference payments are only made when all available capacity is required. If it is set too low, there is a risk that some high merit order plant may be exposed to making difference payments at a point when it is still out-of-merit[20], and will not be earning any compensating energy payments[21].

3.2.3 One option for setting the SP, similar to that used in New England, is to set the SP based on the short run marginal cost of a reference peaking unit, called the "Peak Energy Rents Proxy Unit" in New England. Under this option, the SP of the RO would be defined as:

[20] For simplicity we have ignored inter-temporal issues such as plant not running for start-up costs / time constraints

[21] Assuming competition works efficiently and plant is dispatched in merit order

Strike Price = the heat rate x fuel cost of the Peak Energy Rents (PER) Proxy Unit.

3.2.4 The above formula is intended to ensure that the ROs are only called, and that RO holders only pay out when they receive scarcity rents from generation (or demand reduction) – for example when the energy price exceeds the Short Run Marginal Cost (SRMC) of a Peaking Unit. In an energy only market, peaking plant would need to be able to retain scarcity rents to cover their (fixed and variable) costs, but in an energy and capacity market, the peak plant should be adequately recompensed through the capacity mechanism. We note that in New England, the PER Proxy Unit is an oil or gas-fired generating unit with a heat rate of 22,000 Btu per kWh, and the fuel is a spot oil[22] or gas[23] price, whichever is the most expensive. This equates to plant with a thermal efficiency of only about 15.5%, resulting in high SPs and ROs which are rarely called. Such an approach reduces risk for all capacity providers, but potentially at the risk of blunting incentives, if the Strike Price is above the marginal cost of even the highest marginal cost plant on the system. It also reduces the risk to intermittent generators, if the chance of them having to make difference payments at a time when they are not generating (or indeed at any time) is low.

3.2.5 The use of a spot gas / oil price could lead to volatile SPs, but if related appropriately to the cost of a genuine peaking unit, would hedge the peaking unit and accurately reflect capacity providers' rent. Volatile SPs could be a concern to Suppliers, as the price above which they are hedged using a RO would vary with the spot gas/oil price. This could be mitigated if other forward CfDs are appropriately re-designed to dis-apply above the variable SP.

3.2.6 The logic behind using a peaking unit appears reasonable, however there are a number of questions that remain such as:

- **Should we adopt the "floating" Strike Price approach**, which is indexed to the spot oil or gas price? Whilst this indexing may create volatility in the SP, it is risk reducing for a peaking generator as the SP is correlated with its fuel price. A fixed SP could lead to a peaking generator having to make difference payments even though the market price for its energy is less than its fuel cost, if fuel prices rise unexpectedly.
- **How do we choose the reference unit**? There are a number of potential approaches that could be considered, including:
  - The avoidable (fuel) costs of the **actual** plant on the system that is likely to have the highest such costs. This is consistent with an assumption that plant will continue to bid its avoidable costs. A prudent margin could

[22] ultra low-sulphur No. 2 oil measured at New York Harbour
[23] day-ahead gas measured at the Algonquin City Gate

be included to cover uncertainties such as the transportation cost of fuel, or a margin to cover timing differences in the purchase of fuel.

- A **hypothetical** best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum in the SEM could be used[24]. This is a hypothetical new plant, which may be more fuel efficient than the highest marginal cost plant on the system at the present time. Some may argue the BNE approach may be consistent with encouraging efficient exit of capacity.

Should a conservative approach be taken to choosing the reference unit and setting the SP, if a hypothetical unit is chosen? In New England, the reference unit has a low thermal efficiency- lower than any plant likely to be running in the All-Island market and considerably less efficient than the current SEM BNE reference plant, which the manufacturer claims can achieve greater than 38% in simple cycle. This protects generators from the risk that they do not have peak energy rents to offset RO difference payments, but may lead to weaker incentives on plant to be available when needed.

- **Do we grandfather this reference unit** when auctioning long term agreements for new build capacity, or should this reference unit change over time to reflect changes in technology (as the SEM BNE peaking plant does)? The approach of allowing the reference unit to change over time is consistent with encouraging efficient entry, e.g. by updating the heat rates (thermal efficiency) as new plant becomes more efficient. However, it increases risk for new build generators, who are exposed to changes in the level of the SP which are unrelated to changes in their own costs over the course of a contract which may last a number of years. However, if there are multiple grandfathered RO SPs applying in any given delivery period (because multi-year RO contracts were agreed with different grandfathered SPs), for a generator or Supplier, designing a contract portfolio to hedge accurately across the full price range becomes difficult.

3.3 REFERENCE MARKET - INTRODUCTION

3.3.1 The market reference price (MRP) is one of the critical factors in the design of the CRM product and the performance incentive mechanism. ROs are referenced against a specific near-term or spot market, or a blend of the various markets in which physical energy is traded.

3.3.2 The basic principle upon which ROs are based is that the pricing mechanism, through the reference market, both incentivises reliable performance by capacity providers

[24] The Calendar 2015 BNE plant is an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

and drives long term investment decisions. There are a number of obvious potential choices for the MRP including each of the proposed I-SEM energy markets:

- **The Balancing Market (BM) price**. Whilst the Energy Trading Arrangements (ETA) workstream is still consulting on the details of the BM price formation[25], the I-SEM HLD established that there will be a single marginal imbalance price[26].

- **The Intra-Day Market (IDM) price**. This market will be a continuously traded market, like the IDM across North West Europe and therefore will not provide a single easy price reference against which ROs could be struck. The EU Target Model provides that intra-day regional auctions may also be implemented under certain conditions; however there remain questions as to how such auctions can be implemented alongside continuous trading.

- **The Day-Ahead Market (DAM) price**. The I-SEM design envisages that the majority of energy physically traded in the I-SEM will be traded via the DAM, and that the DAM will provide a liquid market and transparent price for forward contracting. The DAM will also be the market more strongly coupled to the wider European Internal Market through the price coupling mechanism provided by the EUPHEMIA algorithm.

3.4 PRICING SCARCITY IN THE I-SEM

3.4.1 As noted above, the I-SEM HLD stated that the I-SEM will employ a single marginal energy imbalance price. The recent I-SEM ETA Detailed Design Markets Consultation Paper set out the detailed design of the imbalance pricing arrangements for the I-SEM and developed a number of options for setting the imbalance price[27]. While the ETA Markets Consultation and Decision Papers will establish the pricing mechanism for setting the imbalance price under normal conditions, in this section of the CRM Detailed Design, we consider how the imbalance price would be set under scarcity conditions, i.e. in the event of unserved load or an inability to maintain target operating reserve levels- depending on the definition of scarcity chosen.

[25] In particular: how non-energy actions will be stripped out; and how “marginal” the marginal action used to calculate the price will be e.g. the last MW of energy balancing, or the average over the X MW where X>1.

[26] i.e. unlike the System Buy Price (to be paid by market participants who go into Gate Closure short) and the System Sell Price (to be paid by those who go into Gate Closure long) in the current GB arrangements- although the GB mechanism is currently being reformed to move to single cash-out price

[27] See: http://www.allislandproject.org/en/wholesale_overview.aspx?article=95576707-dd90-479a-b631-630178cca133

3.4.2 Scarcity pricing relates to an additional performance incentive mechanism that may be applied to the standard reliability options product and the reference market against which the RO provides price coverage. We do not consider it appropriate to introduce administrative scarcity pricing in the I-SEM in isolation to the CRM given the important role that ROs provide as a hedge to demand under scarcity conditions. Therefore it is appropriate to consider whether scarcity pricing should be implemented in the I-SEM.

3.4.3 Ofgem, in their recent 'cash out' reforms have introduced scarcity pricing into the cash out pricing mechanism as have a number of markets in the United States (US). The Great Britain (GB) Capacity Mechanism was implemented in conjunction with the cash out reforms and while there is no direct hedge provided by the capacity mechanism in GB, Ofgem considered that in time RO could emerge as a hedge around a scarcity price. Scarcity pricing, if implemented in the I-SEM would need to be implemented in conjunction with ROs and would expand the scope of the forward hedge provided by the CRM to cover high administrative scarcity prices at times of tight margins.

3.4.4 Given that the design of the balancing market in I-SEM will be closer to the prevailing design in the markets in North West Europe such as the GB market than the current SEM, we have examined GB imbalance prices over the period 2012-2014 and the extent to which these imbalance prices reflect scarcity. Whilst there have been few, if any genuine system stress event during this period, nevertheless it is recognised as a period in which overall capacity margins have been tight.

3.4.5 As illustrated in Table 3-1 analysis suggests that:

- From 2012 to 2014, the highest GB DAM price was £262.50/MWh;
- The last time that National Grid issued a Notice of Insufficient Margin was in February 2012. However the highest System Buy Price (SBP, the price paid for accepted generator offers, excluding for transmission reasons) during that month was only £264/MWh;
- In Calendar years 2012 to 2014, of over 52,000 settlement periods, only 37 SBPs were in excess of £200/MWh, with the highest SBP being £430/MWh. Whilst this may reflect the averaging approach currently employed in the GB BM price setting, there is no evidence to suggest that prices have risen to reflect scarcity;
- There have been more instances of high prices in the SEM during this period, even though there has been more spare capacity in Ireland than GB. The SEM has had around 300 instances of ex-post SMP prices above £200/MWh, and a maximum of nearly £880/MWh. Even the Ex Ante day ahead estimate of the SEM, which will not reflect forced outages that occur on the day, has more high price outcomes than GB.

Table 3-1 Comparison of GB and SEM high price events, 2012-2014

No. Of half hours 2012-2014

£/MWh	GB Day Ahead	GB BM System Buy Price	SEM Ex Ante Day Ahead estimate	SEM Actual Ex Post
>£150/MWh	20	196	643	598
>£200/MWh	11	37	259	287
>£300/MWh	0	8	40	74
>£400/MWh	0	2	8	20
>£500/MWh	0	0	0	10

Maximum price in any half hour

	GB Day Ahead	GB BM System Buy Price	SEM Ex Ante Day Ahead estimate	SEM Actual Ex Post
Max price £/MWh	£262.50	£429.10	£484.63	£878.90

Source: ESP calculations

3.4.6 The fact that the SEM has an explicit mechanism for the recovery of start-up and no-load costs leads to high SMPs on occasions when peak generating units start up for very short periods. The move to the I-SEM, which like the GB BM, does not have a formulaic mechanism for recovery of start-up and no-load costs, may lead to fewer instances of high prices than occur in the SEM, even if bidding rules are not retained. For these reasons, the I-SEM BM may not accurately reflect scarcity value, and incentivise the marginal plant to make itself available.

3.4.7 Any administered capacity price should be set in a manner that is consistent with the expected frequency of a scarcity event in a system that has just enough capacity to meet the security standard. This will vary with the definition of a scarcity event, for example

- **Actual load reduction:** a scarcity event could be defined based on actual load reduction (e.g. through a voltage reduction). The expected incidence of such scarcity should average out at the security standard LOLE (currently 8 hours for the SEM)

- **Reduced reserve:** a scarcity event could be defined as the point at which all available capacity has been used up, so that any further increase in demand will erode the reserve margin. This will be a more frequent (albeit still rare) event than an actual load reduction

3.4.8 Further detail on how scarcity pricing would be triggered in the balancing market is set out in a series of Ofgem documents[28] and we will develop our thinking on this as part of the implementation of the CRM and development of detailed market rules.

3.4.9 The key argument for an administrative scarcity price is that the last bid scheduled still does not meet the requirements[29], and more expensive bids would have been scheduled, if they had existed. Different approaches exist for determining the administrative scarcity price. As discussed later in this Section, they include:

- BNE Cost based; and
- Value of Lost Load (VOLL) based.

3.4.10 In the remainder the section, we discuss the key principles / objectives which should determine the choice of MRP, before evaluating the pros and cons of the options against these principles / objectives. We consider scarcity pricing in the imbalance market in a number of options for the MRP set out below.

3.5 KEY FACTORS DRIVING CHOICE OF MRP

3.5.1 The following are key factors to consider when deciding upon the MRP:

- **Security of supply: The MRP should incentivise availability at times of system stress**. The choice of MRP should incentivise the provision of capacity when it is really needed, which may only be known very close to real time (such as in BM timeframes). Whilst certain drivers of scarcity (e.g. a cold snap, low wind) may be predictable with reasonable certainty at day-ahead stage, others (e.g. forced outages) may only be known very close to delivery. Price signals, should ideally reflect system conditions as close to real time as possible;
- **EU Internal Market: Optimisation of interconnector trading**. The choice of reference market could influence interconnector trading. If the choice of reference price drives generators to withhold power at the day ahead stage to sell in the BM, this may lead to sub-optimal scheduling of interconnector flows in the EUPHEMIA day-ahead run ;
- **Efficiency: Accessibility**. The MRP should be accessible (i.e. achievable) by capacity providers. It is desirable that the generator should be able to sell into this reference market and achieve the MRP. This minimises generator risk, and

[28] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

[29] Whether define as system demand, or system demand + operating reserve requirement

improves the investability of the market and hence promotes efficiency objectives;

- **Competition: Promotion of wider liquidity objectives**. The choice of MRP could influence which market generators choose to sell their physical power in. If, for instance, the BM price is made the MRP, generators could be incentivised to sell power in the BM, and divert liquidity from the DAM to the BM[30]. **However, there are potential solutions to this issue, such as making it compulsory for RO holders to submit offers in the DAM**;
- **Competition: Market power controls**. If there are controls on bidding or market prices, such as the Bidding Code of Practice (BCoP), this could impact on the incentivisation of capacity provision at times of scarcity and could lead to the requirement for alternative provisions such as administered scarcity pricing.

3.6 MARKET REFERENCE PRICE OPTIONS AND EVALUATION

3.6.1 We have considered the following key options:

- Option 1: BM price
  - Option 1a: BM price without scarcity pricing;
  - Option 1b: BM price with scarcity pricing
- Option 2: 100% Intra-day price;
- Option 3: 100% DAM price;
- Option 4: Multiple reference market option:
  - Option 4a: A blended price option;
  - Option 4b: A split market price option.

Option 1a: Balancing Mechanism price without Administered Scarcity Pricing

3.6.2 The key argument in favour of the BM price as the MRP is that it would better reflect real time system stress than any other market price. As a result, a BM price would better incentivise capacity providers to make capacity available at times of genuine system stress.

3.6.3 Certain elements of system stress, such as weather (temperature, and to some extent wind) are reasonably predictable at day-ahead stage and can be expected to be priced into the DAM and IDM prices. However, they will be less reflective of actual system stress than the balancing price. In particular, if system stress is due to sudden forced

[30] Particularly at times when there is a reasonable probability that a stress event will occur

outages, these outages will not be priced into the DAM. They will not be priced into the IDM price either, if they occur after Gate Closure.

3.6.4 That being said, the BM price may still not fully reflect scarcity at times of system stress. If there are regulatory caps on BM bids or prices, these regulatory constraints could prevent BM prices (or DAM or IDM prices) from rising high enough to reflect system stress / scarcity. For instance, if the current BCoP was retained:

- The BM prices could only rise as high as the SRMC of the marginal generator. So the BM price could not reflect scarcity value[31] and could not incentivise a marginal generator to generate by earning a marginal revenue greater than its SRMC; and
- If the SP is indexed to the SRMC of the marginal generator, by definition the RO could not pay out.

3.6.5 There might also be some unintended consequences of using BM prices as the MRP for ROs such as:

- **Draining liquidity from the DAM**: if the BM is used as the RO MRP, generators may be incentivised to align all their CfD hedging strategies around the BM price (ensuring that two-way Directed and Non-Directed CfDs do not apply above the RO SP), and sell all their power into the BM rather than the DAM to minimise their risk. **One possible way to alleviate this concern would be to make it mandatory for any RO holder to bid into the DAM**. However, this is likely to impose risk on generators if they have to sell power in the DAM and some of their financial contracts are referenced to the BM, and they may seek to reflect a risk premium in their DAM bids, if regulatory arrangements permit them.

  In ISO New England a solution with "virtual" generator bids has been implemented. In this market, a generator can offer its full availability into the DAM. However, if for any reason the generator wants to have availability to sell power into the BM, it can buy-back its power from the DAM by putting in a "virtual buy bid". This adds to the demand side of the market, and potentially increases liquidity rather than reduces it. It can then re-sell this power in the BM. This design allows the generator to bid its costs into the DAM, and facilitates merit-order dispatch, whilst still being able to sell into the BM, thereby covering its obligations for any ROs set against the BM price.

- **Sub-optimisation of interconnectors**: If a BM MRP does cause generator to withhold power from the DAM, or to include a significant risk premium on

[31] Where scarcity value is defined as price in excess of short run marginal cost

DAM sales, it could lead to sub-optimisation of trade across the interconnectors- note there is no such equivalent driver causing analogous generator behaviour in GB. The EUPHEMIA algorithm is optimised at day-ahead stage. If there are missing generator offers because generators have withheld power from the DAM, scheduling could be sub-optimal at the Day-Ahead stage- frustrating one of the key objectives of the I-SEM.

- **Capping BM prices and blunting energy market price signals**: It could be argued that generators holding ROs would have no incentive to offer a price above the RO SP. Any increase in the BM price would merely increase their difference payment liabilities commensurately, blunting the incentive to reflect scarcity in their bids.

  However some generation capacity is likely to have greater availability than RO volume, due to a number of reasons such as de-rating, load following (see Section 4) or the fact that there may be significant BM price setting plant not eligible to participate in the CRM. Therefore, there are likely to be occasions when the BM price will rise above the RO SP, and the energy market price signal would not be blunted in all instances.

Option 1b BM with Administered Scarcity Pricing

3.6.6 Regulatory constraints or market failures may mean that even the BM may not fully reflect scarcity value at times of system stress. In order to address this, some markets incorporate an administered price solution into the real time energy market (whether the BM or an Ex-Post Pool price) when there is insufficient available capacity. For instance:

- Certain US markets have administered Pool prices where there is insufficient capacity to meet demand plus operating reserve requirement; and
- The GB market is moving to incorporate VoLL into the BM price as part of Ofgem's cash-out reform[32]. GB bases its determination of insufficient capacity on a more extreme definition (it requires actual unserved energy, not just a reduction in operating reserve below target), but the principle of an administered scarcity price is the same.

[32] On 2 April 2015 the Authority directed that Mod P305 be made to the Balancing and Settlement Code, effective from 5 November 2015. Among the changes is 'VoLL pricing': the inclusion of a cost for disconnections and voltage reduction into the cash-out price calculation based on an administrative Value of Lost Load (VoLL), and a process for correcting parties imbalance volumes in these events. GB starts with a VoLL price of £3,000/MWh on 5 November 2015 before moving to £6,000/MWh on 1 November 2018

3.6.7 As stated above, the options for the detailed design of imbalance price setting in the ETA Detailed Design- Markets Consultation Paper are all based on a single imbalance price. An administered scarcity price can be incorporated into any of the three options for price formation in the ETA design.

3.6.8 There are at least two options for the formulation of the administered scarcity price:

a) **BNE Cost based**: The administrative scarcity price can be set based on the annualised cost of an additional hypothetical best new entrant divided by average scarcity hours per year; or
b) **Value of Lost Load (VOLL) based**: The VoLL is an estimate of the maximum value that consumers would have been prepared to pay for continuity of supply and is a measure of the opportunity cost of unserved load. Provided VoLL has been determined accurately, this would be the correct price for scarcity events based on actual load reduction.

3.6.9 The use of the BNE or VOLL based price should result in a similar result, if the security standard is set using appropriate cost benefit techniques.

3.6.10 Administered Scarcity Pricing in the BM is strongly linked to additional performance incentives in the CRM as set out in the following sections which consider how incentives for over and underperformance would be applied as a function of the scarcity price.

3.6.11 The advantages and disadvantages of this option are the same as for Option 1a, except that the incentives to be available in the BM are stronger, due to the expectation of a higher BM price, when it includes a scarcity element.

Option 2: Intra-day Market Price

3.6.12 The proposals for the IDM arrangements are less developed than the proposals for the DAM or the BM. The EU Target Model envisages a pan-European intra-day trading platform which facilitates re-optimisation of the market across the EU after the Day Ahead auction and up to “Gate Closure”, one hour before delivery. As a result, the IDM price is more likely to be reflective of scarcity than the DAM, but less likely than the BM.

3.6.13 However there are a number of other issues with using an IDM price as the MRP:

- **Illiquidity**: There is no guarantee that the IDM will be liquid, as participants may not need to trade frequently in IDM timescales.
- **Accessibility**: The IDM prices could vary considerably over the timeframe in response to outages and changes in weather, and we would need to define an

averaging methodology. A generator could end up selling its power at a substantially different price to the reference price. More liquid markets, such as oil markets get around this problem by having a narrowly defined time window against which contracts are settled. InterContinental Exchange (ICE) Brent futures are settled against the weighted average price of trades during a two minute settlement period from 19:28:00, London time. This encourages traders to trade during this window to achieve the settlement price, and drives liquidity towards this two minute window. However, this merely focuses liquidity in an already liquid market, and is unlikely to be a solution for the I-SEM unless liquidity is much improved.

Option 3: Day Ahead Market Price

3.6.14 The DAM is possibly the most obvious source of the market reference price. This is due to a number of reasons, including:

- **Primary Liquid Spot Market**: It is likely that the DAM will be the primary spot market in which the majority of energy will be traded in the I-SEM. DAM will be the most liquid and accessible market for the trading of physical positions by both load and generation. It is reasonable to expect that capacity providers could be confident of capturing the DAM reference price to back up their liability. Using the DAM price therefore avoids basis risk for Generators and Suppliers, and should further enhance liquidity of the DAM. It is also the market against which CfDs are likely to be written, thereby enabling suppliers to have a full hedge (CfD + RO) under all market conditions.

- **Cross Border Trade:** The DAM would facilitate cross-border trading by:

    - Ensuring that generators are incentivised to bid their energy into the DAM, rather than withhold energy / capacity until later timeframes, so that the EUPHEMIA optimisation at Day-Ahead stage reflects all genuinely available capacity; and

    - Aligning the reference price with the Financial Transmission Rights (FTRs) (which at this point we assume will be referenced against the difference between the GB and ISEM DAMs).

3.6.15 **Provide a reasonable hedge against price spikes:** A DAM reference price would provide a reasonable hedge for suppliers against price spikes. It is likely that a significant proportion of price spikes will be driven as a result of generation outages, changes in wind speeds or adverse weather conditions which are known or can be reasonable predicted in the DAM timeframe, and it is likely suppliers will have procured their expected demand in the DAM market, rather than the BM. In terms of longer term security of supply, the liquidity of the DAM can also be seen as important in determining the incentives from the energy market for new entry (or exit) – for example, by providing strong and robust reference prices to support forward trading and a route to market for uncontracted generation.

3.6.16 The key drawback of the DAM price is that it may not provide an adequate signal of system stress. Times of system scarcity may only become fully apparent in real time, e.g. due to forced outages which occur with no notice. In this instance DAM reference price does not reflect scarcity / system stress as well as the BM price (with or without an administrative scarcity price). Use of a DAM reference price would dilute incentives for capacity providers to be available when they are needed the most. However, a non-marginal generator (with fuel cost less than the RO strike price) will still have some financial incentive to make its capacity available, in order to earn an energy net margin in the BM.

Option 4a and 4b: Multiple reference price options

3.6.17 A multiple reference price option (hybrid approach) could be considered, to overcome the disadvantages of using a single MRP, such as those outlined above. These options could work with either a balancing price with administered scarcity pricing or without and could take the form of:

- **Option 4a: A blended price option**. The RO Reference Price is calculated as a volume weighted average of the reference price in the markets where the capacity provider sold its energy in any given settlement period. This weighted average Reference Price for the settlement period, varies from settlement period to settlement period and from capacity provider to capacity provider depending on where the capacity provider sold its energy. However, the weighted average price applies to 100% of the capacity providers RO volume in that settlement period. In this example, if a generator with a 1MW RO sold 90% of its energy in the DAM and 10% of its energy in the BM, the whole 1MW of RO would be settled against an index that was 90:10 weighted average of the outturn DAM and BM price;
- **Option 4b: A split market price option**. In this option, there are two (or three[33]) separate reference prices. Any energy that a capacity provider sells in the DAM is settled against the DAM price, whereas any capacity for which energy has not been sold in the DAM is settled against the BM reference price. Under this option, in the above example 0.9MW of the RO would be settled against the DAM price and 0.1MW of the RO would be settled against the BM

[33] The option could be extended to reflect volumes sold in the Intra-Day Market

price. Additionally, if a scarcity event was to be called at the BM then the volumes of the RO (0.1 MW in the example shown), regardless of whether the capacity provider actually chose to sell the volume in the BM i.e. the RO holder could not avoid settlement of unsold volumes against the BM price by withholding capacity. In other words, the volumes settled at the BM price is always equal to the full capacity of the RO minus the amount settled in the ex-ante markets.

3.6.18 Since the RO is a one-way CfD, Option 4a and 4b payouts and incentives are different[34.]

3.6.19 There are a number of drawbacks with Option 4a, including weaker incentives and complexity. Another limitation is that if generators sell a high proportion of their output into the DAM, the incentive properties would be relatively weak. For instance suppose that it is mandatory for generators to make offers into the DAM. They could chose to hedge the power they expect to sell into the DAM with a CfD with a DAM reference price, and only sell their marginal capacity in the BM when it was required. This behaviour might be expected in a well functioning market. However, consider the example of a generator which sells 90% of its output into the DAM at €150/MWh, and then there is a sudden scarcity event which drives the BM price above the RO Strike of €200/MWh to €250/MWh. The MRP is calculated as (90% x 150 + 10% x 250) = €160, i.e. below the €200/MWh Strike Price even though a scarcity event has occurred. So no RO difference payments are made, just like in Option 3 (100% DAM price), due to the high weighting of the DAM price in the MRP.

3.6.20 The Italian CRM which is based upon ROs is due to hold its first auction in 2015. We believe that the Italian scheme is likely to be of the Option 4b form. The reference market will be a weighted average of the day-ahead market (MGP) and the ancillary service market (MSD) and Balancing Market(s), (MB). Holders of ROs will be required to offer into the day ahead, ancillary services and balancing markets. Volumes accepted in the DAM will be settled against the DAM reference price if the option is called. If volumes are not accepted in the DAM and accepted in the ancillary services or Balancing Markets, the option is settled against those markets (pay as bid or pay as cleared) depending on which market its bid was accepted in and whether there was a system stress event.

3.6.21 Key features of Option 4b are that it:

- Incentivises capacity providers to bid into the DAM, since accepted volumes are settled against the DAM price
- Contains strong incentives to make any remaining unsold capacity available in a real time scarcity event- as illustrated in the worked example below.

[34] With a two-way CfD they would average out to the same outcome

3.6.22 Assume that at day-ahead stage, scarcity is not expected and the DAM price is €150/MWh, and a generator decides to proceed with some planned maintenance. If its fuel cost is €150/MWh of electricity output- a level at which its marginal cost equals its marginal revenue. Now if the price spikes in the BM to €250/MWh, the generator is now incentivised to sell all of its output in the BM as a result. Under Option 4b, all of this generation would be subject to RO cashout at the BM based MRP, i.e. €250/MWh against a SP of €200/MWh, so the generator has to pay a difference payment of €50/MWh on all its output under the RO. It earns a spark spread of €100/MWh on this output in the BM, so has net earnings of €50/MWh from returning to service

3.6.23 Option 4b may generate complexity for generators and Suppliers in developing energy price hedging strategies and calculating how to disapply Directed and Non-Directed Contracts above the RO SP. Each generator will have two different RO SPs that apply to a varying proportion of its RO volume, with that volume varying from settlement period to settlement period and only being known at delivery.

Summary of Market Reference Price options

3.6.24 We have summarised the pros and cons of the various options in Table 3-2 below. The summary assumes that it is mandatory for RO holders to offer energy in the DAM in order to address concerns about DAM liquidity (otherwise the cons of options with a strong BM component are self-evident).

3.6.25 The RA project teams will continue to liaise closely on interactions between the CRM, ETA, Market Power, Forwards/Liquidity and other workstreams, as appropriate, to ensure a coordinated approach to design and implementation, regarding interactions between the choice of reference market and scarcity pricing and other aspects of the I-SEM design

Table 3-2: Summary pros and cons of different MRP options (if make DAM bidding mandatory)

Option	Pros	Cons
Option 1a: BM price	• Close to real time, so more likely to reflect system stress, and better incentivise availability at required times than DAM or IDM	• Capacity provider may face basis risk on RO if mandatory DAM offers accepted, but payout is against BM price • Potential for reducing liquidity in DAM • Potential limited incentives on marginal generator
Option 1b: BM with Scarcity Price	• Strongly incentivises availability at times of system stress • Would allow a strong performance incentive mechanism for over-delivery as well as under-delivery	• Capacity provider may face basis risk on RO if mandatory DAM offers accepted, but payout is against BM price • Potential for reducing liquidity in DAM • High risk for capacity provider if it fails to deliver (but risk can be capped)
Option 2: 100% Intra-day price	• Closer to real time than DAM, so more likely to reflect system stress	• Lot of uncertainty about liquidity • Lack of price accessibility as continuously traded market unless intra-day auctions implemented • Weaker than BM at incentivising availability at times of system stress • Would not provide hedge for scarcity prices if implemented in BM
Option 3: 100% DAM price	• Price robust and accessible to capacity providers • Promotes efficient day-ahead EUPHEMIA scheduling • Consistent with existing approach to CfDs and likely approach for FTRs	• Weaker than BM or IDM at incentivising availability at times of system stress • Would not provide hedge for scarcity prices if implemented in BM
Option 4a: Blended price	• Mitigates capacity provider basis risk • Could be implemented with scarcity pricing in BM.	• Significantly weaker than pure 100% BM option at incentivising availability at times of system stress- MRP likely to be close to DAM price and have same issues as Option 3 • Creates complexity for generator and Supplier hedging strategies?
Option 4b: Split market price	• Provides right incentives on non-marginal capacity • Mitigates capacity provider basis risk • Could be implemented with scarcity pricing in BM.	• May create complexity for generator and Supplier hedging strategies

3.7 LOAD FOLLOWING OBLIGATION

3.7.1 The MW volume on which difference payments are made need not necessarily equal the total volume of RO contracts awarded at auction. If the obligation to make payments is triggered at a time when the requirement for capacity (e.g. defined as system demand plus capacity required to provide operating reserve) is different to the total volume of ROs sold, then each RO obligation can be scaled down[35] pro-rata to reflect:

(Actual demand – Capacity provided by plant without an RO commitment + Operating Reserve Requirement) / Volume of RO sold

3.7.2 Therefore if a period of system stress happens unexpectedly outside peak demand periods (e.g. due to low thermal plant availability combined with low wind), the RO obligation is scaled down by the load following adjustment.

3.7.3 The arguments in favour of this load following adjustment are that it:

- Leaves capacity providers (as a group) and Suppliers exactly hedged above the Strike Price[36], and they would not be otherwise;
- Ensures that difference payments balance as a result; and
- Ensures that the difference payment accurately reflects scarcity value.

3.7.4 However, the examples below illustrate that whilst it is true if all capacity is within the mechanism (and if operating reserve requirement is ignored), it is not true when there is significant plant outside the RO mechanism, e.g. if renewables are ineligible.

3.7.5 If we consider the following example, where 6,000MW of ROs had been sold to generators, and there is no capacity without ROs. Suppose that the actual scarcity event occurs when demand is 5,400MW- to keep this illustrative example simple we have ignored operating reserve requirements. In this example, the RO would be scaled down to 0.9MW per MW of RO sold (i.e. 5,400/6000) for this settlement period.

3.7.6 Suppose that the Strike Price is €200/MWh, which reflects the short run marginal cost of the marginal capacity unit, and the MRP was €5,200/MWh.

3.7.7 Assume further that generators had sold all their power into the real time market, and therefore earned €5,200 x 5,400MW = €28.08m. Of this, €27m (€28.08m – €200 x 5,400MW) is scarcity rent, i.e. relating to payments in excess of the cost of the marginal plant.

3.7.8 Since the obligation is load following, the difference payments that capacity providers have to make equals (€5,200-€200) x 5,400 MW, i.e. exactly equal to the scarcity rent that capacity providers have received from the real-time market. These payments also exactly match the amount that Suppliers have had to pay in excess of the €200/MWh Strike Price. Therefore the effect of the scaled load following obligation leaves capacity providers and Suppliers exactly hedged above the Strike Price.

[35] It is not clear that scaling up should occur, as the generators have delivered their contracted volume, and the key issue is that the SO's estimate of demand was low

[36] Individual capacity providers will not be hedged if they under/over-deliver

3.7.9 If the obligation is not load following, but set equal to the 6,000MW originally sold, the capacity providers would have to make difference payments equal to €30m (6,000MW x (€5,200 - €200)). This is more than the total energy payments that capacity providers received from real time markets, significantly more than the scarcity rents they received, and more than the costs imposed on society - since they relate to a larger volume than consumers actually required.

3.7.10 If this $30m was paid to Suppliers, they would receive a windfall gain from the scarcity event, since the €30m is more than their total payments of €28.08m – assuming they had paid the real time price for all 5,400MW of energy.

3.7.11 Consider instead, if there is 1000MW of ineligible capacity, and the scarcity event occurs when demand is 6,400MW. The RO is scaled, as before with the ineligible capacity making up the other 1000MW of demand. However, the ineligible generators do not have to make difference payments on the 1000MW of capacity they provide. There are only 5,400MW of difference payments from RO capacity providers, and Suppliers will be left unhedged on 1,000MW of their demand which they have bought at €5,200/MWh.

3.8 PHYSICAL PERFORMANCE INCENTIVES

Case for physically based performance incentives

3.8.1 In theory, the basic RO alone provides strong financial incentives to be generating when the options are exercised, since the holder has to pay out the difference between the market price and the option strike price. If the RO holder is generating then it can sell its output in the market at or close to the reference price and hence back off its exposure.

3.8.2 The initial design of Capacity Mechanism based on RO in the US and in Colombia[37] paid relatively little attention to explicit incentives based on physical performance. They relied solely or predominantly on the incentives contained within the basic RO to incentivise capacity delivery at times of system stress.

3.8.3 However, both the US and Colombia markets have found that various market constraints have prevented the RO difference payments alone delivering physical capacity when needed. As a result, in recent years, they have increasingly moved to introduce further incentives during times of system stress on physical performance to complement the incentives embedded in the basic RO, and the reforms are ongoing.

[37] Although the original design for the Colombian RO included provision for physical performance incentives, they were not implemented.

3.8.4 In the thermal dominated power systems of the North East of the US such as the ISO-NE and PJM markets, the combination of spikes in gas prices and caps on wholesale market prices have combined to render the RO insufficient to incentivise generators to generate at times of system stress. If the key driver of both gas and power demand is cold weather, a cold snap drives gas prices high. Unless there are additional performance incentives, there is insufficient incentive on a gas peaking unit to generate, unless it can reflect the increased gas spot prices and a small spark spread[38] in its power price bid. If regulatory constraints prevent generators increasing bids to this level, they will be disincentivised to run.

3.8.5 In the context of the SEM, bidding caps such as the BCoP are a potential example of such a market constraint. These constraints need not be as explicit as the BCoP, and could include market participants concerns with regard to an ex post regulatory investigation. Blunted incentives on marginal generators to price above the RO strike price may also limit the incidence of scarcity being reflected in market prices.

3.8.6 As explained in ISO-NE (2012)[39,] "at times of greatest need, many resources are delivering far below the performance ability represented in their supply offers" (this underperformance was quantified as up to 40% of the additional power required by the System Operator during contingencies)[40]. As a result, the US capacity markets are in the process of being reformed to sharpen physical performance incentives, and address the so-called "missing performance" problem.

3.8.7 The key drivers may be slightly different in the hydro dominated Colombian system, but they have also moved to sharpen physical performance incentives. The I-SEM CRM design should reflect the lessons learned from these other markets[41].

3.8.8 In the remainder of this section we discuss additional performance incentives based on physical performance, drawing on examples from the US and GB, including the:

- Form of additional incentives;
- Scarcity based triggers for incentives;
- Caps and floors on incentives;
- Performance incentives for renewables and DSUs; and
- Summary of emerging conclusions.

[38] The spark spread is the difference between the power price and the gas price, taking appropriate account of the thermal efficiency of the generator. In European markets with carbon pricing, the "clean" spark-spread also takes into account the cost of carton emissions

[39] ISO-NE, Independent System Operator of New England (2012). FCM (Forward Capacity Market) Performance Incentives. Working document released in October 2012

[40] See Mastropietro, Rodilla and Batlle (2015). http://www.iit.upcomillas.es/batlle/Publications/2015%20Capacity%20mechanisms%20and%20performance%20incentives%20_%20Mastropietro%20et%20al.pdf

[41] For example as above

3.9 FORM OF PHYSICAL PERFORMANCE INCENTIVES

3.9.1 The information that we have collected from US and GB markets suggests that additional incentives could be effective in incentivising physical performance:

- Based on an individual capacity provider's physical capacity provision at times of system stress;
- Are relative to a capacity provider's adjusted load following obligation, not the capacity provider's total RO volume;
- Have adjustments for SO instructed deviations in output;
- Are levied on a per event basis;
- Contain provisions for additional payments for over-delivery as well as reductions in payments for under-delivery. The reductions for under-delivery can be such that payments are negative for some periods; and
- Are subject to caps and floors.

3.9.2 We discuss some of the key elements of the ISO-NE and GB physical performance regimes below.

ISO-New England Case Study

3.9.3 In 2014 the ISO-NE developed a new incentives regime for the New-England forward capacity market. A few 'near miss' situations forced the ISO to consider whether the previous penalty regime was effective in delivering performance during stress events and incentivising sufficient investment. The ISO concluded that the capacity payment was not aligned to resource/participant performance resulting in a lag in investment and a decline in performance. The solution was to implement the new Pay-for-Performance (PFP) 2-settlement incentive regime.

3.9.4 A capacity provider's market revenue consists of three parts:

- A base capacity payment determined via an auction;
- A deduction for peak energy rents – the RO difference payment; and
- An additional performance payment, which can be a positive amount for over-delivery and a negative amount for under-delivery as described below.

3.9.5 The performance payment would be determined by the capacity provider's performance whenever scarcity conditions occur and an over/under delivery prices under administrative scarcity conditions.

3.9.6 The net effect of the performance regime is that it re-distributes money from capacity providers which have under-delivered versus their adjusted load following obligation to those who have over-delivered. The total amount charged to Suppliers (or Load Serving Entities as they are called) is unaffected.

GB Case study

3.9.7 DECC consulted on the GB penalty regime through 2013 and 2014. DECC's Impact Assessment update of September 2014 sets out the rationale for the final detailed design choices.

3.9.8 At the theoretical level, DECC explains that a penalty regime should be designed to reintroduce incentives that are not present in the market due to the missing money problem. DECC recognised, that in a perfectly efficient energy only market, missing money occurs at times of lost load when the price should rise to VoLL. Here, the level of missing money is estimated at VoLL minus the energy cash-out price. DECC considered that having a separate capacity market changes the trade-off between penalties reflecting the full degree of missing money versus reducing the risk for investment in new capacity. Two options were discussed to manage this trade-off: 1) a cap on liabilities in the capacity market; 2) lower level of VoLL.

3.9.9 In GB, the standard payment for availability is determined by the auction outcome. The 2014 auction clearing price is £19,400 per MW p.a. – equivalent to a rate of £2.21/ MW per hour of availability. The payment of this amount is subject to "satisfactory performance"[42].

3.9.10 The performance incentives, applicable only in system stress periods work as follows:

- There is a penalty, subject to certain caps, when a Capacity Market Unit (CMUs) metered production is less than Adjusted Load Following Capacity Obligation (ALFCO) and additional payments when it exceeds this ALFCO;
- The penalty rate in £/MW/h of availability is 1/24th of the indexed price for capacity which is expressed as £/MW per year. For the 2014 auction clearing price of £19,400 per MW pa, this implies a penalty rate of £808 per MW/ h of availability (before indexation);
- There is a payment for over-delivery by a CMU in relevant settlement periods based on an Over Delivery Rate (ODR). The Over-Delivery Payment is based on:
    - An ODR which is equal to Min (penalty rate for the CMU, the average market penalty rate); and

[42] Which in practice requires that the capacity subject to an obligation be demonstrated a number of times, depending on the Capacity Market Unit (CMU) type, in the winter of the delivery year. These demonstrations may occur at any time in the winter period. Details are set out in Section 13 of the Capacity Market Rules .

- The production that exceeds ALFCO for the CMU.

3.9.11 This ODR has the effect of providing an additional incentive to return to full availability even if the penalty cap is reached.

3.9.12 Penalties and over delivery payments need not balance and there can be in aggregate a positive or negative sum.

3.9.13 Importantly, DECC originally consulted on a penalty rate range from £1000-3000/MWh. This consultation was considered alongside Ofgem's Electricity Balancing Significant Code Review proposal to introduce scarcity pricing to cash out prices up to £6000/MWh at times of system stress for demand control and reserve utilisation. DECC considered that Ofgem's reform already provided a strong energy market incentive for performance, and therefore the capacity market penalty represented a top-up to the cash-out price. Overall DECC considered that the cash-out price limit at £6000/MWh was sufficiently high to incentivise performance and topping this up would provide minimal additional benefit in terms of performance.

Scarcity based triggers for incentives

3.9.14 A key question is whether performance incentives for physical capacity delivery in the I-SEM would only apply at times of when the system meets a physical definition of system stress, or whether they would apply at all times. Using a scarcity based trigger for incentives would ensure that rewards are focussed on times when capacity has genuine value.

3.9.15 The definition of scarcity could be:

- Availability is less than demand plus operating reserve requirement. This definition of scarcity is consistent with using a BNE based administrative scarcity price for over/under delivery, or with a VoLL price scaled with the Loss of Load Probability (LoLP) to reflect the fact that the probability of lost load is less than 1; or
- Where there is unserved load. This definition is consistent with using a VoLL based scarcity price for over/under- delivery.

3.9.16 Note that incentives based on physical scarcity could apply to payments for over-delivery of capacity in excess of a capacity provider's contracted RO volume (e.g. on its de-rated capacity – see Section 4), as well as being reflected in RO difference payments via incorporation of scarcity pricing into the BM.

Caps and floors on incentives

3.9.17 Most jurisdictions place limits on the size of performance incentives. The economic rationale for caps on the size of incentives include:

- To ensure that the payments/charges for under/over-delivery do not exceed the amount that consumers would be prepared to pay for the energy / reliability; and
- To achieve an appropriate balance of risk and incentives on capacity providers. Capacity providers can be expected to price risk into their capacity auction bids, so an appropriate balance should be struck between the cost of risk and the value of increased performance to consumers.

3.9.18 The structure and level of limits employed in ISO NE and GB are discussed below. Our research suggests that the limits employed in GB and ISO-NE ensure that capacity providers cannot lose money out of the capacity regime over the course of a year, even if they deliver no availability, and cause system stress as a result. Such an approach does not appear economically efficient in that it does not allow the market to charge under-performing capacity providers for the true cost they impose on society.

3.9.19 The performance incentives in the CRM should also be considered in conjunction with the incentives embedded within the energy market. For instance in GB, where administrative scarcity pricing (in the form of VoLL) will be reflected in the energy balancing market, there may be a need for tight caps and floors on Capacity Mechanism incentives than in a market where there is no administrative scarcity pricing.

New England

3.9.20 Performance incentives are subject to the following caps in the ISO NE market. The caps on penalties are limited to approximately:–

- 5% of annual capacity revenues for a shortage event;
- 1% more per hour after 5 hours, for shortage events greater than 5 hours;
- 10% on any day;
- 2.5 months capacity revenues in one month;
- 12 months capacity revenues in one year;

3.9.21 Generators and import resources can manage their exposure to performance incentives through reconfiguration auctions and by bilateral contracts which have the effect of reducing or shedding the obligation.

GB

3.9.22 There are monthly penalty caps (equal to twice the monthly payment) and an annual capacity cap which is stated in the Capacity Market Register. The annual cap is set at

100% of the annual revenue- i.e. a market participant cannot lose over the course of a year by participating

3.9.23 Penalties and caps are applied per CMU and not to the portfolio.

Performance incentives for renewables and Demand Side Units

3.9.24 Ideally all eligible capacity providers should face the same performance incentive regime including requirement to pay difference payments, and any additional performance incentives for under or over delivery of physical capacity at times of system stress.

3.9.25 Equivalent treatment for certain classes of capacity provider such as intermittent renewables can leave these capacity providers with significant risk, but this risk reflects the risk they place on the system as a result of their unreliability.

3.9.26 In practice, there are often exemption and special treatment for certain classes of capacity provider, in order to de-risk the capacity regime for them and encourage investment. For instance, we understand that in New England, penalties do not apply to intermittent renewables and demand side capacity providers can lose no more than their monthly base payment (whereas conventional generators can lose 2.5 times their monthly base payment). However this comes at a cost to consumers since every MW that is not subject to a performance incentive is a MW that a supplier is purchasing at the scarcity price, as the RO is no longer providing a hedge.

3.9.27 In GB intermittent plant is ineligible, so the issue does not arise. We understand that there are no specific carve outs for Demand Side Response in GB.

3.9.28 The fuel mix in the I-SEM will differ greatly from other markets, in the System Non-Synchronous Penetration SNSP levels will be significantly higher. This places a unique risk on the network it may be prudent to reflect this in the performance regime.

Incentives and penalties during the pre-commissioning phase

3.9.29 The GB capacity regime introduced a series of penalties and incentives for new capacity to ensure that:

- It is possible to monitor the progress of new capacity against milestones to assess whether the capacity is on track to deliver before the delivery period starts; and
- Take early remedial action, including re-tender for that capacity, if the capacity provider fails to meet key development milestones.

3.9.30 Whilst we think that it is appropriate to flag the requirement for any such Implementation Agreements in this consultation, the design of this regime will be further consulted upon at a later stage.

Summary of performance incentives

3.9.31 The performance incentives regime should be considered in its entirety taking into account the :

- Incentives that are reflected inherent in the energy market design, including imbalance charging;
- Choice of MRP;
- Additional performance incentives for physical performance; and
- Caps and floors on both RO payouts and the physical performance incentives.

3.9.32 If a high administratively set scarcity price is introduced at around €5,000-10,000/MWh, the incentives are significantly stronger than if the MRP is purely based on a BM price which (in GB at least) never rises much beyond £200-£300/MWh.

3.9.33 The experience of the US markets suggests that there is merit in introducing additional performance incentives for physical delivery of capacity, in addition to administrative scarcity pricing.

3.9.34 We see advantages in the New England style performance score design, in which the performance regime is revenue neutral, transferring money to capacity providers who over-deliver from capacity providers which under-deliver, with Supplier payments unaffected.

3.10 SUMMARY OF QUESTIONS

3.10.1 The SEM Committee welcomes views on all aspects of this section, including:

A) The approach to setting the Reliability Option Strike Price:

   a. Should we adopt the "floating" Strike Price approach, which is indexed to the spot oil or gas price?

   b. How do we choose the reference unit? Should it be based on actual plant on the system or a hypothetical best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum?

   c. Should we grandfather this reference unit where a multi-year RO is sold by new capacity?

B) The implementation of scarcity pricing in the I-SEM Balancing Market?

C) The choice of market reference price options from amongst the options presented and consistency with key objectives.

D) Whether the RO volume and/or the additional performance incentives should be load-following.

E) The requirement for, and design of additional performance incentives, including:
   a. The form of additional incentives;
   b. Scarcity based triggers for performance incentives
   c. Caps and floors on incentives;
   d. Performance incentives for renewables and DSUs;
   e. Performance incentives during the pre-commissioning phase;
   f. Detail of any other considerations respondents feel that we should take account of when determining policy in relation to product design

4. ELIGIBILITY

4.1 INTRODUCTION

4.1.1 In the High Level Design (HLD) for the CRM, the SEM Committee determined that the Reliability Options (ROs) should be physically backed. The Eligibility criteria will be used to determine whether a capacity provider is eligible to provide the physical backing for a Reliability Option, and how many MW of RO can be backed by a given MW of "nameplate" capacity[43].

4.1.2 It is desirable from an economic efficiency perspective to allow different technologies to compete on an equal basis to provide capacity in the I-SEM CRM. This principle is also enshrined in the EC Guidelines on State Aid for environmental protection and energy (EEAG) that relate to capacity mechanisms, which take as a general principle that all types of capacity that meet physical checking and performance requirements should be eligible. However, the EEAG also recognise that it may be appropriate to limit participation in capacity mechanisms where this is necessary to prevent overcompensation, for example because there is a separate aid scheme for a particular class of capacity provider. The EEAG also requires preference to be given to lower carbon capacity providers in case of equivalent technical and economic parameters and require that demand side and storage operators are eligible to participate.

4.1.3 Where some forms of capacity are excluded from a capacity mechanism, the contribution this capacity makes to security of supply (and will continue to make once the new mechanism is introduced) must be accounted for in generation adequacy assessments, and the calculation of the amount of capacity that needs to be contracted in the capacity mechanism.

4.1.4 The following section considers what physical generation should be eligible to back ROs[44], the treatment of generation receiving support, whether and how physical generation should be de-rated and the criteria for non-firm generation and aggregators. It also considers and sets out options for how demand side and storage participate in the CRM.

4.2 PLANT RECEIVING SUPPORT UNDER OTHER MECHANISMS

4.2.1 Capacity providers on the island of Ireland may be able to recover some or all of their capacity costs through a number of support mechanisms, including:

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[43] "Nameplate" is term commonly used in the context of generation, but is less relevant to demand side reduction, although we recognise that the demand side should be able to participate in the CRM

[44] Either by competing in the I-SEM Capacity auction or via secondary trading

- A range of renewables / low carbon support mechanisms which operate separately in both Ireland and Northern Ireland;
- The PSO backed generation including peat fired power stations in Ireland and legacy Generation Unit Agreements (GUAs) in Northern Ireland; and
- Longer term ancillary service support contracts.

Capacity Providers Receiving Support through Government Renewable Support Schemes

4.2.2 A key question for the I-SEM CRM design is whether supported renewable generation will participate directly in the CRM. The Irish and UK governments already provide support mechanisms for low carbon / renewable generation that ensure that they recover their costs over the lifetime of the support mechanism. In considering the eligibility of these supported generators, it is necessary to consider whether their inclusion would result in overcompensation and hence increased costs to consumers.

4.2.3 Therefore it needs to be decided whether it is appropriate to allow low carbon / renewable generators who are in receipt of support to compete in the I-SEM CRM as part of the principle of allowing all types of capacity to participate, or to make them ineligible to compete, as the UK government has done for the GB Capacity Mechanism. With respect to the exclusion of capacity providers who receive government renewable support in GB, there is a strong correlation between this and the design of the energy and capacity markets in GB[45].

4.2.4 The main renewable support schemes on the island of Ireland include:

- Ireland:
  - REFIT 1-3. The existing REFIT regime commenced with REFIT 1, which received State Aid approval in 2007 and the REFIT 2 and 3 which received State Aid approval in 2011. The existing REFIT 3 regime is open to new applicants until the end of 2015, and a new support scheme for renewable electricity is currently under consideration by the Department of Communications, Energy and Natural Resources (DCENR); and
  - Legacy Alternative Energy Requirement (AER) contracts, which pre-date the REFIT scheme.

[45] While the GB Capacity Market was introduced in to recover the missing money problem and de-risk investment in the short to medium term, it was brought about in parallel to Ofgem's reform of the imbalance market where price formation in the imbalance market has been made 'sharper' to send the correct economic signal. Low carbon generation in GB are eligible to participate in and receive scarcity rent through the energy market if available during scarcity periods.

- NI:

  - Renewable Obligation Certificate (ROC) regime. The existing ROCs regime, which has been in operation since 2005 is being phased out and is expected to be replaced with the new FiT CfD regime, although generators under this scheme may continue to receive ROCs until 2037.
  - FiT CfDs. Under the UK Feed-in-Tariff (FiT) Contract for Difference (CfD) regime, NI low carbon generation was not eligible to bid in the February 2015 round of UK FiT CfD auctions alongside GB generators. However, NI generation may be able to bid into the UK FiT CfD auctions in the future.

4.2.5 The UK government has taken the view in GB, that where low carbon generators have FiT CfDs, the generator should be precluded from receiving capacity payments and preference for low carbon generation was given through the carbon price floor[46]. The situation is slightly different on the island of Ireland, since under the SEM, supported renewable generators have also received SEM capacity payments, whereas no GB generators have received capacity payments since 2001.

4.2.6 In Ireland, under the terms of the REFIT schemes, capacity payments reduce the level of subsidy payments made through the PSO support scheme. Making existing REFIT generators ineligible is unlikely to significantly change their net income or have a material effect on customer bills, but it will change whether this money is recovered from All-Island market mechanisms or from the Public Service Obligation (PSO) Fund in Ireland.

4.2.7 In the Northern Ireland, under the ROC scheme, if existing ROC generators are made ineligible for I-SEM capacity payments, they will lose revenue, compared to current SEM rules. Unlike under the REFIT scheme, these Northern Ireland generators will not receive an automatic increase in subsidy through the mechanics of the scheme, if they did not receive any payments under a CRM scheme. Customers would benefit in terms of lower bills. However, assuming that the support levels were set at an appropriate level absent capacity payments, there is an argument that NI ROC generators are sufficiently rewarded without additional capacity payments.

4.2.8 The position with regard to future REFIT 4 and FiT CfD schemes has yet to be determined by the respective Departments. In Ireland, the DCENR are due to establish the terms of the REFIT 4 support mechanism in the near future and we expect that consideration will be given as to interactions with the I-SEM energy and capacity markets as part of this process.

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[46] In the EEAG requirement to give preference for low carbon generation in GB was demonstrated through the UK carbon price floor where low carbon generation would be able to bid more competitively in the capacity auction by virtue of the carbon price floor. There is no equivalent of the carbon price floor in Ireland and it does not apply to Northern Ireland generation.

4.2.9 In NI, whilst it would appear simpler and more consistent with GB arrangements for the FiT CfD generators to be ineligible for I-SEM capacity payments, it may be possible to handle either solution through the definition of the market reference price for NI FiT CfDs, which has not yet been determined. If FiT CfD generators are deemed eligible, then the market reference price could include the capacity price, whereas if they were deemed ineligible the market reference price would be only the energy price.

PSO Backed Peat Generation in Ireland and GUAs in Northern Ireland

4.2.10 There are a number of non-renewable generators currently backed via PSO mechanisms in Ireland and Northern Ireland. These include peat fired generation in Ireland and generation backed by legacy generation contracts (GUAs) in Northern Ireland.

4.2.11 There are three peat fired power stations in Ireland. Edenderry power station owned by Bord na Móna has a gross electrical output of 128 MW, and West Offaly and Lough Ree stations owned by ESB, which have outputs of 150MW and 100MW of electrical output respectively.

4.2.12 Edenderry currently sells all its power output to ESB's supply arm, Electric Ireland, under a long term PPA, but that this PPA is due to expire in December 2015[47]. ESB sell the power contracted from Edenderry and its own peat stations into the SEM earning energy and capacity payments[48]. ESB are able to recover any out-of market costs via the PSO fund.

4.2.13 These plants are eligible to receive SEM capacity payments, which are recovered from the All-Island market, and the capacity payments reduce the amount which has to be recovered via the PSO fund in Ireland.

4.2.14 When the electricity industry in Northern Ireland was privatised in 1992 Generating Unit Agreements ("GUAs") were entered into between the Power Procurement Business ("PPB") and generator owners. The agreements contain provisions relating to the purchase of and payment for a number of services including the availability of capacity, the generation of electricity and the provision of ancillary services.

4.2.15 Of the ten original GUAs, only two remain in force. The two legacy GUAs relate to two generating units at Ballylumford power station that are owned by AES. They have a combined capacity of 595MW, and have an expiry date of 23 September 2018 with a five year extension option. The PPB buys energy, capacity and ancillary services under

[47] See http://www.dcenr.gov.ie/NR/rdonlyres/C473558D-64BB-43F5-AA7A-2AB6C22D0B8E/0/EdenderryPower.pdf

[48] Physical power is sold into the Pool, and hedged via PSO CfDs in the forward market

these GUAs at prices determined by the contract, and sell them into All-Island market at market prices. The PPB recovers any shortfall in net revenue from Northern Ireland customers via the Northern Ireland PSO. However, if the market revenue exceeds the amounts paid out under the GUAs, the surplus is used to offset other PSO costs incurred by customers in Northern Ireland.

4.2.16 In 2014, the Utility Regulator consulted on whether to cancel these contracts, and decided not to, estimating that the remaining GUAs are likely to result in reductions in costs for Northern Ireland customers. The Utility Regulator has stated that it will keep under review the value of retaining these contracts for consumers from both a policy and economic perspective.

4.2.17 Both the peat plants in Ireland and the GUA plant in Northern Ireland are material in terms of capacity and it is desirable that they should be eligible to participate in the I-SEM CRM. Incentives may be blunted if the PSOs top up any shortfall in revenues resulting from plant under-performance, or removes any additional revenues resulting from over-performance. However, it is still desirable that in the long term, these plants should be subject to the full incentive regime. In deciding on the eligibility of these supported plants we will need to ensure equitable treatment of supported plant and compatibility with the EEAG.

Longer term ancillary service contract

4.2.18 A further consideration will be to ensure that generation in receipt of long term ancillary service contracts are not over compensated through the CRM. This will be a key consideration in relation to the design and coordination of auctions for both the CRM and DS3 programme. It will be important to ensure that there is alignment for the auction processes for CRM and DS3 to ensure consumers are protected and investors are appropriately incentivised. In this respect, detail on the CRM auction design will be covered in a subsequent consultation paper.

Summary of options

4.2.19 A number of options have been developed that could be used to treat generators in receipt of support. They include making:

- **Option 1: All supported generators ineligible** as in GB;
- **Option 2: All existing supported generators** who have been **eligible** for SEM capacity payments are eligible, but future generators will be ineligible.
- **Option 3: All supported generators eligible**.
- **Option 4**: **Scheme by scheme specific treatment**.

4.2.20 The key considerations, pros and cons of Options 1 to 3 are presented in Table 4-1.

4.2.21 Option 4 would allow for differential treatment of supported technology depending upon which **scheme they are supported under.** The pros and cons of Option 4, depend upon which approach is taken for each specific scheme- in extremis Option 4 could end up like Option 1 or like Option 3. However, the eligibility treatment would need to be based on clear criteria, which might include *inter alia* whether:

- The combination of capacity payments and the support mechanism allows generators to be over-compensated
- *The relevan*t support mechanism compensates the generator for loss of opportunity to earn capacity payments- which is not necessarily the same as over-compensation
- The generators have a legitimate expectation of continuing to be able to earn capacity payments comparable to non-supported generation;
- Whether the mechanics of the support mechanism mean that any reduction in capacity payments will lead to a different allocation of costs between different customer classes, as a result of any reallocation of costs between PSO and CRM cost recovery mechanisms. A different allocation may occur for two reasons. The PSO support mechanisms recover the PSO costs in Northern Ireland only from customers in Northern Ireland, and PSO costs in Ireland only from customers in Ireland, whereas CRM costs are recovered from All-Island customers. Additionally, the allocation of costs between different customer classes may change within Ireland / Northern Ireland depending on differences between CRM and PSO cost allocation methodologies.

Table 4-1 : Summary of options 1 to 3 for supported renewables

	Comments / questions	Pros	Cons
Option 1: All ineligible	• Change from current eligibility. • Reduces net revenues for existing ROC generators. For most other schemes, no net effect on supported generator revenue. • Where capacity revenue replaced via support scheme, cost burden shifted from All-Island recovery to local Ireland / Northern Ireland PSO recovery.	• Lowest cost to consumers in the case of ROC generators • Lowest distortion on cross-border trade and location of generation, as it follows the precedent set in the interconnected GB market- so supports Internal Market and cross-border Competition- although other differences (e.g. carbon price treatment) may be more material? • Avoids performance monitoring of lots of small generators (if physical performance incentives), until plants were out of support, and subsequently eligible to participate.	• The volume of ROs will be significantly less than the volume of load, leaving suppliers in aggregate unhedged when prices rise above the RO Strike Price[49] for the difference between level of demand and volume of ROs purchased. • Removes capacity payment eligibility for existing generators and is a change in treatment for existing supported generation.
Option 2: Existing eligible, future ineligible	• Will intermittent generators choose to bear risk (if eligible, and participation voluntary)?	• Keeps perceptions of regulatory risk low • Lower distortion on cross-border trade and location of generation for new generation? • Avoids some performance monitoring of small generators (if physical performance incentives).	• Could result in some over-compensation, depending on support scheme. • Would cost to consumers more than Option 1, in case of ROC generators. • Volume of ROs will be less than the load as amount of future ineligible generation increases, leaving suppliers in aggregate unhedged when prices rise above the RO Strike Price[49] for the difference between level of demand and volume of ROs purchased. • Potentially requires performance monitoring of some small generators (if physical performance incentives).
Option 3: All eligible	• Will intermittent generators choose to bear risk (if eligible, and participation voluntary)?	• Likely to result in the most economically efficient provision of capacity[50]. • Consistent with long term vision as existing generation moves out of support. • Maintains existing position capacity payment eligibility for existing generators and keep perceptions of regulatory risk relatively low. • Volume of ROs will be closer[51] to volume of load, so Suppliers hedges when prices rise above the RO Strike Price	• Could result in some over-compensation, depending on support scheme. • Would come at a cost to consumers in case of ROC generators. • Requires performance monitoring of lots of small generators (if physical performance incentives).

[49] Although depending on market liquidity they may be able to hedge any residual volume with two-way CfDs similar to existing Non-Directed Contracts

[50] Subject to appropriate de-rating approach, and provided intermittent generators are subject to the same performance incentives as dispatchable generators. If a separate set of performance incentives are developed that are more lenient then intermittent backed generation may not be fully incentivised to participate in the most efficient manner

[51] If participation by supported generators is mandatory, and demand forecasts accurate then the volume of ROs should be close to load at times of system stress. However, if participation is voluntary, and the (for instance) significant volumes of wind generation choose not to bear the associate risk, then RO volumes could still be significantly lower than load

4.3 RENEWABLES NOT RECEIVING SUPPORT UNDER OTHER MECHANISMS

4.3.1 There are renewable generators that are not covered by these support mechanism. At the moment, these are principally long established hydro generators, including stations such as Ardnacrusha (85MW), Erne (65MW), Liffey Stations (38MW) and Lee stations (27MW). Additionally, over time, the support received by other currently supported renewables will expire and we expect that these generators will become 'merchant' operators participating in the energy and capacity markets provided that they meet the physical testing and performance requirements.

4.3.2 In general, it is important to maintain the principle that all forms of capacity should be eligible to participate in a capacity mechanism. This complements the principle in the EEAG relating to the fuller integration of RES into the market, whether future European electricity markets pay explicitly for capacity or not.

4.3.3 Under the current capacity mechanism existing wind generators are paid on the basis of metered output (approximate 30% load factor) rather than their capacity credit (approximately 10% of nameplate capacity). Assuming that the new capacity mechanism includes a system for de-rating of capacity eligible for auction the level of capacity payments to intermittent renewable energy sources may decrease (see de-rating section). Furthermore, depending on the product design, intermittent renewable generators may consider it a more prudent risk management strategy to earn scarcity rents through the energy market only rather than through the capacity mechanism.

4.3.4 Whilst intermittent plant cannot be guaranteed to deliver its full rated capacity at times of system stress, statistically, there is high probability that it will deliver non-zero capacity at these times, providing some contribution to system security. This is grounds for making intermittent plant eligible to back the RO, at least based on a de-rated capacity. We understand, for instance, that intermittent plant is eligible to bid its de-rated capacity into the ISO NE market.

4.3.5 Overall, the inclusion of unsupported renewable, including intermittent renewable, plant on a de-rated basis would appear to be consistent with EU State Aid guidelines.

4.4 MANDATORY VERSUS DISCRETIONARY BIDDING FOR ELIGIBLE GENERATORS

4.4.1 We may choose to make bidding mandatory for eligible generators, in order to prevent abuse of potential market power. The concern would be that a portfolio generator could withdraw capacity from the auction in order to drive up the market clearing price, and earn a higher capacity payment on the rest of its generation portfolio.

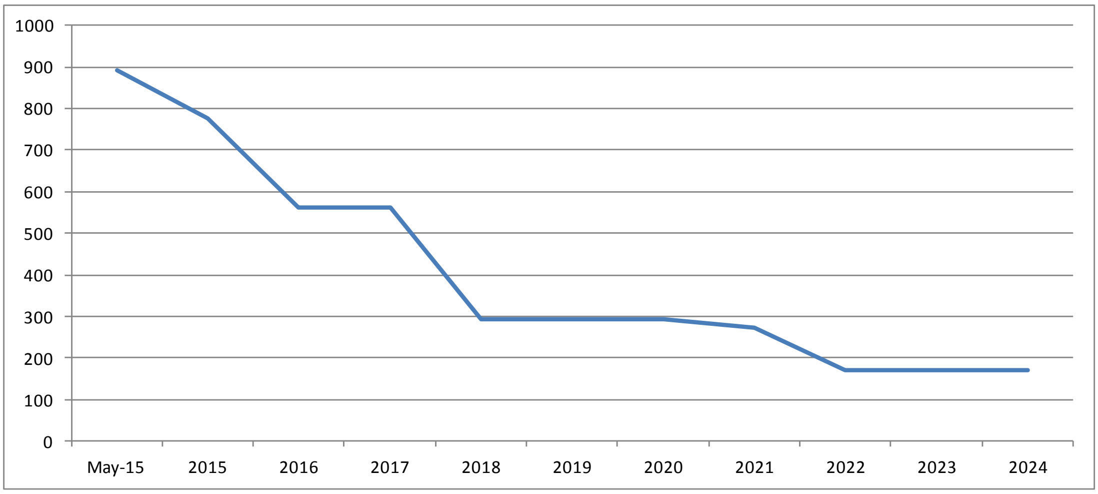
4.4.2 In GB, existing capacity was required to explain any capacity withdrawal of existing plant- and needed to justify non-bidding in terms of the plant being retired before the end of the delivery year. The GB auction also had rules on the highest price at which existing generators could withdraw from the descending clock auction.

4.4.3 There are other ways, however, to address these potential gaming issues. For instance, the capacity procurer could adjust down the amount of capacity bought if a generator which was expected to contribute capacity chose not to bid. We envisage that this approach will be employed to adjust the capacity requirement for renewable / low carbon generation anyway, if they are deemed ineligible to bid, or if they are risk averse and choose not to bid.

4.5 TREATMENT OF GENERATION WITH NON-FIRM TRANSMISSION ACCESS

4.5.1 Detailed projections from the TSOs suggest that there is as much as 900MW of conventional (i.e. dispatchable, non-renewable) generation, which currently has non-firm transmission access rights. This is projected to decline to around 550MW in 2017, when the I-SEM starts, and to 300MW in 2018. However, some conventional generation is still predicted to have non-firm access by 2024, the end of the projection window.

Figure 4-1 : Total non-firm conventional generation capacity (MW)



Source: TSOs

4.5.2 This includes some conventional generation which has not been given firm access because it may frequently be constrained off in favour of wind generation due to transmission constraints. However, it may be required if times of system stress coincide with periods of low wind output.

4.5.3 Options for the treatment of non-firm access generation in the I-SEM energy market were set out in the ETA Building Blocks Consultation Paper. In particular, the SEM Committee is considering whether non-firm generation would be compensated in constrained relative to ex ante market positions (the Day Ahead and Intra-Day markets). Eligibility for non-firm generation in the capacity mechanism will depend on the ability of this capacity to access the reference market for the RO and therefore we will ensure that the treatment of non firm generation in CRM is consistent with the SEM Committee Decision on the Energy Trading Arrangements.

4.5.4 If some of this non-firm access generation is a potentially cheap form of capacity, there is a strong argument to allow it to compete in the I-SEM CRM. If they are not eligible there is the risk that this plant cannot recover its fixed cost, is retired, and has to be replaced at greater cost by new plant. This is the right outcome if they are not able to contribute at system stress, but potentially the wrong outcome if this non-firm capacity is providing back up to wind generation, and it is low wind that is the main cause of system stress in the future.

4.5.5 However, even if it is eligible to bid, non-firm generators may be reluctant to do so (assuming CRM bidding is discretionary rather than mandatory), if they cannot guarantee that they will be generating at times of system stress and may be subject to penalties.

4.5.6 Options for the treatment of non-firm generation include:

- **Option1: Eligible to bid, subject to the same de-rating factors** as firm generators of the same technology;
- **Option 2: Eligible to bid, subject to additional de-rating** (for transmission access, as well as technology specific). The additional de-rating would depend on the relationship between the exit capacity from the constrained zone, demand in the zone and wind generation in system stress scenarios;
- **Option 3: Ineligible to bid**.

4.5.7 Refer to Section 4.9 for a discussion of “de-rating”.

4.6 ADJUSTING THE CAPACITY REQUIREMENT FOR NON-CRM BIDDING GENERATION

4.6.1 Some generation may not be eligible to seek an RO contract. Additionally if bidding is not mandatory, some generation may choose to continue to operate without a capacity contract. For example, it may plan to de-commission part way through the contracted period, or it may take a commercial view that it achieves a better risk / return trade-off by operating without a capacity contract.

4.6.2 In each case it is necessary to reduce the quantity of capacity required through the auction to account for that which does not need to be procured- the sum of the "de-rated" capacities of the plant which is ineligible or chooses not to bid (see Section 4.9, for discussion of "de-rating"). To do otherwise would result in the procurement of more capacity than is required to meet the defined security standard. This could go against two of the assessment criteria that the SEMCO decision will be based upon:

- **The Internal Electricity Market:** The EU requires that capacity to be procured through a CRM be consistent with a defined security standard. In the absence of this adjustment, the CRM would procure more capacity than is required for the security standard
- **Efficiency:** In the absence of this adjustment, the CRM will procure more capacity than is required for a security standard, thereby increasing the cost to consumers.

4.7 DEMAND SIDE PARTICIPATION

4.7.1 Demand Side Participation can lead to the more efficient provision of capacity, where the opportunity cost of reducing consumption is less than the cost of new generation capacity provision. Additionally, the lack of effective demand side participation is often cited as a contributor to generators' wholesale market power.

4.7.2 The EEAG include the requirement that generation adequacy measures should be open and provide adequate incentives to operators using substitutable technologies, such as demand-side response or storage solutions. The European Council of 22 May 2013 called for particular priority to be given to more determined action on the demand side[52].

4.7.3 A key consideration for the CRM is how to allow Demand Side Participation to participate. There are three categories of demand side units that currently operate in the SEM.

- End consumers who have the capability to reduce demand at times of systems stress. This could include large industrial customers, or small and medium sized customers, including residential customers, if they have the capability to respond to price or other signals of system stress.
- Generation capacity which does not have the capability to export to the grid (and hence may be treated differently from other generation), but which has

[52] RA paper quotes source as: (SWD (2013) 438, Nov 2013)- need fuller reference for Con Doc

the capability to reduce the end consumers' net demand from the grid at that site if it generates- e.g. back-up generation
- Generation capacity with the ability to export its generation, and also has the capability to reduce end consumers' net demand if it generates.

4.7.4 In the current SEM, provision has been made to allow DSUs to participate, and there does not appear to be any real distinction between on-site back-up generation and genuine load reduction.

4.7.5 Most customers that keep back-up generation onsite do so for a number of reasons:

- Security: to ensure continued operation in the event of an outage on the grid (e.g. hospitals)
- Commercial risk: to provide a physical hedge against wholesale price spikes
- Capture value: to capture upside from flexibility both through the wholesale market, ancillary services (and the CRM)

4.7.6 These incentives appear to drive delivery at times of peak, which is consistent with the objectives of the CRM. The key to enabling entry of these players will be minimising barriers to entry and ensuring the RO provides strong enough incentives to ensure that the value of capacity that would otherwise be sitting idle, is unlocked by parties such as aggregators.

4.7.7 Whilst demand side participation and aggregation will be facilitated in the I-SEM CRM, it will be necessary to determine the terms under which the demand side will participate. It has been argued that unless specific new provisions are included to accommodate DSUs, DSUs will be at a disadvantage relative to generators. The stated argument is that generators receive energy payments from the wholesale market to offset potential RO difference payments whereas a DSU does not receive an energy payment (except for exports to the grid). However, the DSU (or their Supplier) will avoid an energy payment by virtue of reduced consumption. Two high level proposals have been proposed, which improve the competitive position of DSUs, including introducing a new energy payment for reduced consumption and exempting demand side participants from RO difference payments.

4.7.8 The RAs therefore seek feedback on the relative merits of the following three options:

- **Option 1:** DSUs do not receive an energy payment (in addition to avoiding an energy payment) for foregone consumption, and are subject to the same RO difference payments and any other incentives for physical performance as generators;
- **Option 2:** DSUs receive a new energy payment for foregone consumption, but are subject to the same RO difference payments and any other incentives for physical performance as generators; and

- **Option 3:** DSUs do not receive a new energy payment for foregone consumption, but are exempt from RO difference payments. However, they are subject to other incentives for physical performance imposed on generators.

4.7.9 These options are illustrated in the following worked examples. Let us assume that:

- DSU unit X is a large industrial consumer, which can provide demand side response by reducing load, but does not have its own generation.
- DSU unit X holds 1MW of Reliability Option. It would normally consume 3MWh of demand in a (one hour) settlement period, but if called on to deliver capacity can reduce consumption and consume just 2MWh;
- The strike price for the Reliability Option is €200/MWh;
- The Clearing price in the auction is the equivalent of €5/MW per hour of availability
- In settlement period t, there is scarcity event and the market reference price outturns at €300/MWh
- DSU X has a contract with a Supplier under which it pays €80/MWh for its metered energy consumption, with no minimum consumption requirement.

4.7.10 Then total net remuneration for DSU unit X, assuming it delivers 1MW of load reduction under the different DSU options in settlement period t, are as set out in Table 4-2 below, with positive values denoting a positive cashflow from the DSU perspective.

4.7.11 In Option 1, the DSU gets paid €5 for delivering 1 MW of demand response for 1 hour, but pays out €100 in RO difference payments. It pays its Supplier €160 for the 2MWh of energy it still consumes. This compares with the €240 it would have paid if it had taken 3MWhs, so it has saved €80/MWh in energy payments, its Supply contract price, by reducing its consumption. In this example, this avoided energy cost is significantly less than the wholesale value of energy during this settlement period, which is €300/MWh, because the Supply contract price is assumed not to be indexed to the spot market price. However, if the Supply contract price has been indexed to the wholesale spot price, DSU X would have received the full €300/MWh benefit.

4.7.12 In Option 2, the DSU gets paid this €300/MWh, as well as avoiding €80/MWh in payments to its Supplier (which could have been €300/MWh if the Supply contract price was indexed to the wholesale spot price). In Option 3, it does not receive the €300/MWh value of wholesale energy, but is exempted from the requirement to payout the €100/MWh difference payment.

Table 4-2 : DSU worked example- demand response delivered

Option	Base capacity payments in period t	Difference payment in period t	CRM energy payment for load reduction in period t	Energy payment to Supplier for energy consumed	Net payment
1	5	-100	0	-160	-255
2	5	-100	300	-160	45
3	5	0	0	-160	-155

4.7.13 If the DSU failed to deliver on its commitment to provide 1MW of capacity, and continued the consume at a rate of 3MW, the net remuneration would be as follows, before the application of any additional incentives for failing to deliver physical capacity.

Table 4-3 : DSU worked example - demand side response not delivered

Option	Base capacity payments in period t	Difference payment in period t	CRM energy payment for load reduction in period t	Energy payment to Supplier for energy consumed	Net payment
1	5	-100	0	-240	-335
2	5	-100	0	-240	-335
3	5	0	0	-240	-235

4.7.14 These values will contrast with any period in which there is no scarcity, when and we assume when the market reference price will be below the strike price. In such a period, the DSU would consume at a rate of 3MW and hence have a net payment of 3 x 5 – 3 x 80 = - €225/MWh, under all options. By contrast, if they had chosen not to participate in the CRM, their payments to the Suppliers would be -€240 /MWh in all periods, regardless of whether there was scarcity or not, assuming they were not the customers who were rationed in the event of scarcity.

4.8 OTHER POTENTIAL CAPACITY SOURCES AND ENERGY LIMITED PLANT

4.8.1 Other technologies, such as energy storage, may also contribute to system security by providing stored energy at peak times. Such technologies should be able to enter the market if there is a realistic prospect of them contributing materially to system security[53], but there are issues in determining whether they contribute fully. For instance:

- How long is a stress period expected to last?
- Can a technology be guaranteed to deliver for the whole period of system stress, or will energy storage limitations impact their contribution?

[53] The 2015 All-Island Generation Capacity Statement 2015-2024 states, "SONI is in discussions with a renewables development company about connection of a proposed Compressed Air Energy Storage (CAES) Plant in the Larne area... The potential exists for a CAES facility consisting of up to 270 MW of generation and 210 MW of compression. ..".

- If energy storage constraints do limit the length of time for which they can contribute at full capacity, how should this be reflected in their eligibility / de-rating?

4.8.2 Some of these issues may also relate to other existing energy limited plant such as pumped storage or existing stored hydro capability, if such plant cannot run at full "nameplate" capacity for the entire duration of a stress period, however that is defined.

4.8.3 The RAs will work with the System Operator (SO) to define the minimum requirements that energy limited plant must meet, and how their de-rating factor is determined. A potentially simple approach could be to:

- Define a minimum period (consistent with likely length of system stress), x hours.
- Determine de-rated capacity at the maximum level that the asset can sustain throughout all x hours

4.9 DE-RATING

4.9.1 The SEM Committee has taken the position that ROs must be physically backed. Therefore an approach needs to be developed for defining the maximum MW of capacity a given capacity provider will be allowed to back. The approach should be reflective of its ability to deliver capacity at times of system stress.

4.9.2 The amount of capacity which is likely to be technically available may be less than the total "nameplate" capacity to account for an expected level of breakdowns at periods of system stress, known as "forced outage"[54]. The nameplate capacity is said to be "de-rated". If, for instance, a Combined Cycle Gas Turbine (CCGT) with 400MW is only allowed to back 360MW of ROs, it is said it have been "de-rated" to 90%. De-rating takes account of the availability of plant, specific to each type of generation technology.

4.9.3 If bidding is non-mandatory, eligible generators may be allowed to offer less than this maximum MW, or nothing at all. However, if bidding is mandatory (at least for generators, but not for other types of participants, such as DSUs) then the maximum MW may also be the minimum MW that they can offer.

4.9.4 We will need to determine a de-rating approach to :

- Dispatchable capacity, including:

[54] Generators and other capacity are sometimes also unavailable for planned maintenance, but, a well designed market would incentivise them not to plan maintenance at times of probable system stress

- Thermal generation;
- Pumped storage- particularly Turlough Hill;
- Existing hydro, which is not supported by renewables / low carbon regimes;
- Other Energy limited plant;
- Demand side participation; and

- Intermittent capacity; and
- The Moyle and East-West interconnectors.

Dispatchable generation

4.9.5 A dispatchable (i.e. non-intermittent) generator is unlikely to be able to provide capacity up to its full "nameplate" capacity, since it may be on forced outage at some of the times of system stress, or if the system stress appears at short notice, it may also be on planned outage. Additionally, some of the energy will be consumed internally within the power station and not exported to the system. Therefore we envisage that the "nameplate" capacity will be de-rated.

4.9.6 The de-rating factors applied in the GB 2014 capacity auction are set out in Figure 4-2: GB 2014 de-rating factorsFigure 4-2, by way of example. The GB authorities determined the de-rating factors through a mix of using historical data, and studies of the availability of different generation in other countries with capacity mechanisms aimed at incentivising availability of capacity to meet demand in periods of system stress.

Figure 4-2: GB 2014 de-rating factors

Technology class	De-rating factor
Oil-fired steam generators and oil burning reciprocating engines	82.10%
OCGT and gas burning reciprocating engines	93.61%
Nuclear	81.39%
Hydro	83.61%
Storage	97.38%
CCGT	88.00%
CHP and auto-generation	90.00%
Coal/biomass	87.64%
DSR	89.70%

Source: National Grid, 2014 Four Year Ahead Capacity Market Auction Guidelines

Intermittent generation

4.9.7 The ability of intermittent generators, such as wind, solar and tidal to contribute at times of system stress will depend upon whether the wind is blowing; the sun is shining and the timing of the tides.

4.9.8 If intermittent generation is allowed to compete in the I-SEM CRM, the following needs to be considered:

- **Wind:** the wind strength is likely to be relatively uncorrelated with peak demand, and its ability to contribute unpredictable. Moreover, as the penetration of wind grows, it is likely that times with low wind output will increasingly be correlated with time of system stress- increasingly systems stress could be caused by low generation availability as much as high demand.
- **Solar**: The TSOs project approximately 100MW of installed solar capacity by 2020, mostly in Northern Ireland and mostly small scale. Solar is unlikely to contribute materially at times of system stress, which is most likely to be during peak demand- after dark on winter nights.
- **Tidal**: The TSOs project approximately 200MW of installed tidal capacity in Northern Ireland by 2020[55]. Tidal station output clearly varies with the tides, and may not be able to contribute at all to peak capacity depending on whether the time of system stress aligns with the tides or not. Whilst there may not be material amounts of tidal capacity at the moment, any investors in tidal generation are likely to want to understand the position of their plant with regard to capacity remuneration.

4.9.9 Whichever approach is chosen, the methodology should be aligned with the methodology for setting the overall capacity requirement. If intermittent generators are deemed ineligible, then the amount of capacity procured via ROs should be calculated net of expected capacity contribution of all intermittent plant. However, if intermittent capacity is deemed eligible, the amount of capacity procured should be calculated net of the expected contribution of any intermittent capacity that chooses not to bid.

[55] See All-Island Generation Capacity Statement 2015-2024

Interconnectors

4.9.10 De-rating will apply to the interconnector's maximum capacity regardless of whether an "interconnector-led" approach or a "generator- led" approach is employed[56]. With a "generator-led" approach, additional de-rating is likely to apply to generators connected via the interconnector, compared to an equivalent generator connected on the island of Ireland, to account for interconnector unreliability.

4.9.11 Interconnectors contribute to system security. However, their contribution depends upon the ability to import into the island of Ireland at times of system stress, which in turn may depend upon the extent to which spare capacity is available in other jurisdictions. The All-Island Generation Capacity Statement indicates that the East-West and Moyle interconnectors contribute approximately 800MW in 2024. This is less than the combined 1000MW of their capacity.

4.9.12 In response to requirement for EU participation in the GB capacity market, DECC decided that interconnector owners may participate in the capacity market on an equal footing with other Capacity Market Units. In other words, they will be able to bid their de-rated capacity in the 2015 capacity auction and, if successful, the benefit and obligation of a capacity agreement. This means they would face penalties if energy imports on the interconnector were less than their load following capacity obligation. Since owners of interconnectors do not have their own generation, interconnectors which hold a capacity agreement will rely on differential energy market prices to ensure that the direction of flow is to import to GB. Interconnectors can only ensure that the capacity is available and that the arrangements for linking the markets at either end are efficient at the relevant timescales.

4.9.13 DECC's decision notes that "This is an interim solution until a common EU approach for the participation of cross -border capacity in capacity remuneration mechanisms is introduced". We will consider interconnector related issues in further detail in a later consultation process.

Key de-rating issues

4.9.14 Where possible, a common framework for de-rating should be employed, and there are a number of generic issues including:

- Generic de-rating factor by technology or plant specific;

[56] Interconnector-led approach means the CRM rights are assigned to the interconnector owner. Generator-led approach means CRM rights are assigned to a generator on the other side of the interconnector which can prove it has interconnector capacity rights.

- Historic vs. projection approach;
- Marginal vs. Average; and
- Grandfathering.

Generic or plant specific de-rating factor

4.9.15 There are two proposed models for the determination of de-rating factors. Both are centrally determined by the TSO:

- **Option 1: Generic Technology de-rating factors**. In this model, a central body would determine the de-rating factors to be applied to each technology type- similar to the approach adopted in GB. Bids must reflect this level of backing. Thus if the de-rating factor for, say a CCGT, was 90%, an owner of a 400MW CCGT could bid for no more than 360MW of ROs in respect of this CCGT.
- **Option 2:"Plant Specific" approach**. Under this approach, a central body would determine maximum de-rating factors for each specific plant on the system. In this example the TSO may consider that a specific plant is old and less reliable than the average CCGT, and may de-rate the plant to below the 90%, reflecting historic outage rates for that plant.

4.9.16 Both of these approaches would set the maximum MW value that could be bid into the RO auction, reflecting the maximum amount of capacity that could be reliably delivered. There may be situations where the capacity owner wanted to bid a value below this level. This will be addressed in the consultation on auction rules, and whether there should be any rules on withholding capacity from the CRM auction, for market power mitigation or other reasons.

History vs. projection approach

4.9.17 It will be necessary to define a methodology for setting the centrally determined de-rating factors. This could be based upon:

- **Option 1: Historical data**. The GB approach used for eligible capacity units was based upon the use of historical data on the availability of different types of technology at times of system stress. This approach may be appropriate for many types of generation assets, but it may be that the expected capacity contribution of other assets in future is significantly different from the past. For instance, it is possible to infer from Eirgird's Generation Capacity Statement [57] estimate that the capacity contribution of the existing interconnectors contribute 617MW of capacity in 2015, but will contribute 777MW in 2020 and 803MW in 2024.

[57] See Eirgrid Generation Capacity Adequacy Statement 2015-2024, compare tables A.16 and A.17

- **Option 2: Projections / modelling**. An alternative is to base a de-rating factor on a modelled future contribution to capacity. However, this raises the question of how to treat assets whose capacity contribution vary over time such as the interconnectors whose projected capacity contribution increases over time, or wind capacity whose average projected capacity contribution per MW installed capacity decreases over time. With the interconnectors, it would be possible to develop a solution where its de-rating factor increases (e.g. from increase 62% in 2015 to 78% in 2020), which would enable them to bid for more RO units in subsequent auctions as more capacity firms up. However, there are different issues associated with wind (if it is eligible), which we discuss under the topic of grandfathering.
- **Option 3**: **Hybrid approach**. The de-rating would be based on historical data with an adjustment based on forward looking consideration where relevant.

Marginal vs. average

4.9.18 The de-rating factor could be based on a unit's marginal capacity contribution, or its average availability. The average capacity contribution of generation unit at times of system stress is likely to be broadly equal to its forced outage rate (assuming that a generator would not plan outage at times of peak demand when system stress is most likely). However, its marginal contribution to system security depends upon:

- **Correlation:** The correlation of its unavailability with other plant unavailability. For thermal plant, forced outages are largely uncorrelated. Whereas for wind plant in a relatively small geographical area like Ireland, the output of the wind industry is highly correlated. An increment of a unit of wind adds significantly less capacity contribution than its average output because if we have a stressed situation due to lack of wind, adding one more wind unit will not change the situation;
- **Diversification effects:** Large thermal systems which have more units, and where the unit are small in relation to system size need smaller capacity margins, not because any individual unit is more reliable, but because the risk is diversified across more generation units. A marginal approach reflects this diversification, whereas an average approach does not.

Grandfathering

4.9.19 This issue is more material for wind than thermal plant, but the issue of grandfathering of de-rating factors is a general one.

4.9.20 The capacity contribution for wind of a marginal MW unit is lower as the volume of wind comes on the system. Suppose for instance, that 1MW of existing wind contributes a marginal 0.2MW to capacity, but that in 5 years time when there is more wind on the average unit contributes 0.15MW and the marginal MW contributes 0.1MW of capacity.

4.9.21 At that time, should the existing wind be allowed to back 0.2MW of capacity (i.e. have its rights grandfathered) and the new capacity only 0.1MW, or should both be allowed to back only 0.1MW of capacity? Could an existing generator bid for RO in the first auction, knowing that the assets that it had now, may not suffice as backing for the duration of a 15 year contract, because its de-rating factor could be reduced? The grandfathering approach gives positive investment signals at the time of the investment and gives certainty to the investor. It also incentivises early rather than late builders in the case of wind.

4.9.22 Different approaches to grandfathering are possible. For instance, in the above example, the generator could have a grandfathered right to 0.2MW for all 15 years, or to a guaranteed but reducing profile- e.g. 0.2MW for the first 5 years, 0.1MW thereafter.

4.10 TREATMENT OF AGGREGATORS AND PPA PROVIDERS

4.10.1 It is possible that smaller generators, including those who currently receive capacity payments based on metered generation, may lack the capabilities to compete in I-SEM CRM. They may, for instance be averse to risks associated with having to make RO difference payments (which are less diversified for a small single site generator than a large portfolio generator). Additionally, estimating how to bid in the auction (i.e. what is an adequate auction premium) may require material trading risk management capability, which is not necessarily part of the skill set of a small generator.

4.10.2 We therefore anticipate that aggregators, such as PPA providers, will be able to fulfil a role as an intermediary by:

- Contracting physical capacity from small capacity providers including Demand Side Response, as well as small generators and energy storage providers; and
- Bidding the aggregated portfolio into the RO auctions

4.10.3 What evidence an aggregator will need to prove that it has physical capacity backing for the RO will be a key consideration. Should the aggregator have to produce contractual evidence, such as a PPA to prove that it has physical backing? Or is that too onerous an obligation? Consultation feedback on this point would be particularly welcome.

4.10.4 Further considerations include:

- Should there be a maximum size of unit that can bid into the RO auction via an aggregator, and if so what is that threshold? For example, the SEM uses a 10MW threshold, above which a unit must bid into the Pool. Prima facia, 10 MW would seem a reasonable value above which an existing capacity provider must bid directly into the RO auction if it chooses to participate in the I-SEM CRM; and

- Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via an aggregator? The 2014 GB capacity auction required capacity providers with less than 2MW to bid via an aggregator. Since the I-SEM is approximately 10% of the size of the GB market, it may be difficult to justify a higher limit, but should we set a smaller limit?

4.11 PREQUALIFICATION

4.11.1 There will be a number of key requirements that providers must demonstrate to be eligible to partake in the CRM auctions. Potential requirements in this regard are presented below.

Existing Plant

4.11.2 For existing plant the requirements may include:

- **Data to support de-rating**: Provider must demonstrate the ability to support any centrally determined de-rating. This will depend upon the de-rating approach taken, but may include *inter alia* data on the plant's recent running history – either output or availability data. For plant with high running *costs, h*istoric output data may indicate few running hours, therefore availability data would be required. However, availability data *is harder* to verify, therefore the use of a benchmark for the reliability of the plant may be required
- **Environmental compliance**: The status of the plant in terms of the Industrial Emissions Directive (IED) should also be checked, to ensure that any restrictions on running hours would not jeopardise delivery under the CRM.
- **Other requirements:** More generally, the applicant would need to demonstrate that it is fit to participate in the mechanism. This could include checks to ensure that the applicant is not subject to any licence breaches, and that the company is credit-worthy

New and Refurbishing plant

4.11.3 Since new capacity for some technologies is not likely to be delivered until about four years after the auction, given requirements for construction lead times, etc. There is a risk that:

- A bidder for new capacity fails to deliver the contracted capacity, due to unexpected delays in construction and /or financial problems;
- A bidder for new capacity could bid with no intention of actually delivering on that capacity in order to manipulate the market ("bed blocking"), in order to benefit from resulting higher energy prices on the rest of its existing capacity portfolio.

4.11.4 These risks can be mitigated by ensuring:

- That bidders have to pre-qualify new capacity by meeting a range of physical and financial criteria, which reduce the likelihood of high risk projects bidding into the auction, and incentivise those who are successful to use their best endeavours to deliver; and
- Setting key milestones which must be achieved over the four year lifetime in the form of an Implementation Agreement. If these milestones are missed, then a party can be stripped of its RO and this capacity re-tendered in an auction just before the delivery year.

4.11.5

4.11.7 Table 4-4 sets out the potential requirements for plant undertaking investment either as new or a significant refurbishment.

Table 4-4 : Potential pre-qualification for new or refurbished plant

Requirement	Why?	Description of requirements	
		New plant (including storage)	Refurbished plant
Planning consent[58]	To demonstrate that the plant has the necessary consents for the investment to proceed	• Relevant planning consents, wayleaves, environmental assessments, etc	• Assume likely to be able to use consents for existing plant
Connection agreement	To demonstrate that the plant can connect to system on time	• Signed connection agreement (with EirGrid, SONI, NIE or ESBN) for the location and technology specified in the CRM application • Need to ensure that connection agreements will be available sufficiently far in advance of forward CRM auction	• Existing connection agreement likely to be sufficient • May need to amend if there is a change to entry capacity
Property rights	To demonstrate that the plant can construct on time	• Land title, access routes, etc • Question whether require all property rights secured for eligibility stage, or just most material elements	• N/A
Financial commitment	To ensure that new plant cleared in the auction has strong incentives to follow through with investment	• Posting of required collateral/performance bonds, and definition of clear milestones • Need to balance the need to provide strong incentives for on-time delivery, with the desire not to unduly increase risk to providers in CRM bids	• Unlikely to be required, but may be considered necessary for significant investments
Business plan	To demonstrate the credibility and economic viability of the project	• Board-approved business plan, with contracts for key elements of delivery secured / sufficiently progressed • Directors' statement	• As for new plant • Include criteria to determine whether refurbishment is a sufficiently material investment to warrant multi-year contract
Status under other subsidy schemes	To demonstrate that the project is not ineligible due to receiving support through other mechanisms	• If renewable plant is excluded from the CRM, a declaration that the plant has not applied for or received any support schemes which would render them ineligible	• As for new plant
Credit-worthiness	To ensure the economic viability of the counterparty	• Potential financial criteria to be determined	• As for new plant
Other	Other requirements	• No previous licence breaches, fraud etc • Check IED status for any operational restrictions	• As for new plant

4.11.8 As set out in Section 6, we expect to assign the role and functions of the delivery body to the TSOs. The delivery body will facilitate the capacity auctions and to monitor subsequent compliance with any milestones that the capacity provider must meet during the build / refurbish phase. Where possible, the pre-qualification process and criteria should be based on existing industry processes.

4.11.9 To ensure a robust process, there will need to be an appeals mechanism in place to ensure that applicants are afforded fair treatment under the established rules. In the GB Capacity Market, the appeals process is broadly staged as follows:

- National Grid (NG) issues its pre-qualification decision to the applicant
- Rejected applicants may first appeal the decision to the NG

[58] The different stages of the planning process could be considered here. For example a planning consent may only be considered complete when all objections or legal challenges have been finalised. This could be a date significantly after the planning consent is applied for.

- NG assesses the appeal on administrative grounds (i.e. check whether the forms have been filled in correctly)
- NG issues its decision on the appeal
- If the appeal is rejected by NG, the applicant has the option to appeal to Ofgem as the regulatory authority
- Ofgem then assesses the appeal on merit (i.e. assess whether the correct decision was made on the available information)
- Ofgem issues its final decision on whether pre-qualification should be granted
- Normal appeal processes on Ofgem decisions could then be enacted

4.12 SUMMARY OF QUESTIONS

4.12.1 The SEM Committee welcomes views on all aspects of this section, including:

A) The options presented in relation to the eligibility of plant supported through other mechanisms;

B) The options for eligibility of demand side and storage providers

C) Do you have a view on the technology vs plant specific approaches to de-rating?

D) Do you have a view on the historic, projection or hybrid approaches to de-rating?

E) Do you have a view on grandfathering of de-rating factors?

F) Do you have a view on options presented with respect to the non-firm generation?

G) What evidence should an aggregator be required to show physical backing?

H) Should there be a maximum size of unit that can bid into the RO auction via an aggregator, and if so what is that threshold?

I) Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via an aggregator? If so what is that threshold?

J) What pre-qualification criteria should be applied?

K) Detail of any other considerations respondents feel that we should take account of when determining policy in relation to eligibility.

5. SUPPLIER ARRANGEMENTS

5.1 INTRODUCTION

5.1.1 This section reviews the basis on which the cost and payments of the planned CRM will be made.

5.1.2 A number of aspects will be considered including:

- A summary of the existing Supplier arrangements
- Relevant features that impact CRM supplier arrangements from other sections of the consultation
- The most relevant Assessment Criteria against decisions will be made
- A review of the Supplier charging issues and options arising in relation to supplier arrangements. In particular, we discuss whether the current approach of charging Suppliers for capacity across all hours is appropriate, or whether the charges should be more focussed on specific hours.
- Credit cover. The existing principles for setting Supplier credit cover could be retained, but we also need to consider whether capacity providers should be required to lodge credit cover. In the I-SEM, capacity providers could have to pay out money (RO difference payments) as well as receive money, whereas in the SEM capacity providers only receive money.
- Exchange rate risk. Exchange rate risk on capacity payments is a feature of the SEM capacity remuneration, but the potential exchange rate risk faced by capacity providers is much greater in the I-SEM, if new capacity providers are going to be awarded long term contracts.

5.2 EXISTING ARRANGEMENTS

5.2.1 The existing capacity mechanism is a fixed revenue mechanism which collects a pre-determined amount of money, the Annual Capacity Payment Sum ("ACPS") from suppliers. It pays this money to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code ("TSC"). The same amount is recovered from suppliers.

5.2.2 The value of the Annual Capacity Payment Sum for a calendar year is determined as the product of two numbers:

- A Quantity (the Capacity Requirement) – determined as the amount of capacity required to exactly meet an all-island generation security standard; and

- A Price – determined as the annualised fixed costs of a best new entrant ("BNE") peaking plant[59].

5.2.3 The capacity payments and charges are levied relative to times of system stress. For generator payments this is determined using a combination of annual load forecasts, monthly ex-ante and ex-post margins based on actual availability compared to metered generation. Payments to generators are weighted, with the highest given to periods where the margin is tightest.

5.2.4 Supplier charges are levied using the annual load forecast. In this method, each trading period within a calendar month is compared to the lowest forecast value. This is considered the trading period where the adequacy issue is of least concern. This gets labelled as the Minimum Forecast Demand and all other trading periods are valued relative to this. The resulting values are normalised leading to a weighting factor applied to each trading period resulting in largest charges on suppliers being applied where the forecast demand for the month is highest. Note using this method results in at least one trading period every month where no charges are levied.

5.2.5 The capacity charges and payments are settled on a monthly basis. A proportion of the generator payment price per MWh is fixed, a proportion is based on the forecast LoLP for the trading period and a proportion is paid on the basis of the ex post LOLP. The same amount is re-charged to suppliers. Even though the total cost of capacity is known with certainty at the end of the month, there is still a need for reconciliation at M+4 and M+13 because the data from conventional consumer meters is not available for some time after each month. Estimates of suppliers' loss adjusted demand in each trading period are refined for each resettlement.

5.3 RELEVANT FEATURES OF CRM FROM OTHER SECTIONS

5.3.1 This consultation addresses the issue of how the capacity requirement will be determined and has discussed performance incentives which will apply to generators who are successful in the auction.

5.3.2 The capacity requirement is likely to be defined on a yearly basis and therefore procurement will take place for a 12 month commitment period. The primary procurement for a given 12 month period, and any subsequent adjustment procurements, will result in a set of agreements or contracts to pay option fees for a minimum of 12 months[60] to all successful candidates. By their nature these payments will be completely predictable before the start of the 12 month commitment period.

[59] Net of infra-marginal rent and Ancillary Services revenue
[60] In the case new and refurbishing plants, these agreements may be for a much longer period.

5.3.3 An important incentive for capacity providers under the Reliability Option agreement are difference payments arising when the energy price in the Reference Market(s) exceeds the Strike Price in the agreement in periods of scarcity or near scarcity. Such repayments are likely to be infrequent and difficult to predict.

5.3.4 The performance incentive section highlights that there could be additional incentives and penalties applicable in periods that meet certain criteria for scarcity. Such an incentive mechanism could involve transferring money from generators who under-perform to those who perform above their commitment level, as in ISO-NE. Alternatively, they could involve a net payment based on an independent assessment of under and over performance, as in GB, implying that there could be an impact on the total costs of the scheme. In either cases, the incidence of these performance incentives will be difficult to predict.

5.3.5 A diagram of the cash flows that results from this payment structure is shown below where a bucket represents the total pot of money to be recovered. The size of the pot for any 12 month commitment period will be equal to:

- The annual option fees;
- Less difference payments (RP-SP);
- Plus or minus the net impact of the additional incentive payments.

5.3.6 The latter two are unknown in advance, and may be volatile. The issue for this section of the consultation paper is how suppliers should be charged for the total net cost.

Figure 5-1: Key payment flows in the proposed I-SEM CRM

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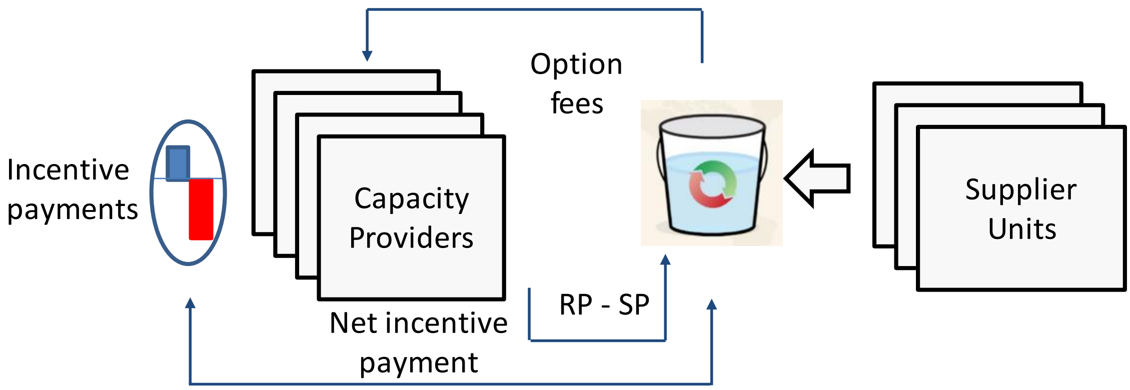


5.4 ASSESSMENT CRITERIA

5.4.1 Looking at the assessment criteria used in the design of the I-SEM as a whole, those that seem to us to have the most bearing on supplier arrangements are set out below:

- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system.
- **Adaptive:** The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

5.4.2 The primary driver of the need for capacity is likely to be consumption in periods of high demand. As the proportion of intermittent generation on the system grows, high demand in itself may become less important; however, conversations with the TSOs indicate that (high) demand will continue to be the primary driver of scarcity for many years to come. Equity and efficiency both argue that it is load in high demand period that should bear the cost of the CRM.

5.5 SUPPLIER CHARGING ISSUES AND OPTIONS

Context and issues

5.5.1 The current CPM is based on a monthly settlement cycle and this is one option in which to settle the CRM. Alternatively the CRM could be collected and paid on a weekly basis (e.g. to match the assumed basis for the settlement of the Balancing Market).

5.5.2 The SEM Committee sees the main issues for supplier charges arising as:

- Whether or not there is any need for a distinct administration charge to recover the cost of the activities of delivery and settlement in relation to the CRM;
- The definition of demand used as a basis for charging; and
- How to reconcile the charges that correspond to this definition of demand with the flow of payments to generators.

Demand used as basis for charging

5.5.3 The costs of the CRM will need to be recovered from Suppliers in proportion to some measure of the demand of their customers. There are two broad options for this measure of demand as follows:

- **Flat:** The charge is applied equally to all demand as a "per MWh" charge
- **Profiled:** The charge is focused on demand at times when there is likely to be system stress - and hence a reduced risk of scarcity.

5.5.4 Efficiency and equity suggest that a profiled approach should be used, as this focuses the costs of the CRM on that demand which drives the overall level of capacity that is required. There are a number of options for how a profile is established for the recovery of costs from Suppliers, with notable examples being:

- **The current SEM Approach - profiled across all hours**: Under the current SEM approach, the costs of capacity are allocated across demand at all times, but at a price which increases for times when incremental demand is likely to increase the need for capacity
- **GB (or similar) approach - focused of specific hours:** The costs of the GB CRM are allocated across that demand which occurs between 4pm and 7pm between November and February. This period is seen as broadly representing the time where an increment of demand would drive an incremental to the level of capacity to be procured through the CRM. A similar approach could be adopted for Ireland, based on analysis of the times when incremental I-SEM demand is most likely to lead to a need for more capacity.

5.5.5 In comparing the above approaches it is notable that:

- Both approaches will improve incentives for demand to evolve in a way that reduces the total need for capacity - and hence the total costs of the system;
- Any approach will need to retain flexibility to reflect changes in *when* an increment in demand leads to a need for more capacity. These changes could result from a number of factors including the increasing deployment of intermittent (e.g. wind) generation, or changes in demand patters following the deployment of smart meters

Reconciling the charging basis with the flow of payments

5.5.6 It is beneficial from a cash flow perspective for payments from Suppliers to match those to Capacity Providers on a month-by-month basis. Notably matching payments means that the TSO (as the counterparty) will not have to borrow money if the payments to be collected from Suppliers are less than those to be made to Capacity Providers.

5.5.7 Achieving this match is not trivial given that:

- **Option fees:** If charges to suppliers are focused on times of system stress, this is likely to imply charging based on demand in winter. Capacity providers might expect to receive option fees in winter and summer;
- **Difference payments and performance incentives:** Difference payments and performance incentive payments will only occur at times of scarcity or near scarcity so are difficult to predict ex-ante.

5.5.8 These two components are discussed in more detail in the following paragraphs.

Option Fees

5.5.9 The existing SEM capacity mechanism divides the annual amount into 12 monthly amounts and pays and recovers these amounts in each month – there is no balance on the account at the end of a month.

5.5.10 The GB capacity market arrangements are helpful benchmark on this point. They *separate* the basis for charging from the flow of payments. Keeping in mind that liability for the capacity charge in GB is based on demand in the period 4pm to 7pm on weekdays in winter, the arrangements operate as follows:

- The TSO prepares a forecast of capacity payments in the next annual commitment period based on the £/kW/pa determined in the auction(s);
- Before the this period starts, all suppliers must submit a forecast of their expected demand in the charging period in the following winter;
- Each supplier is required to pay a fraction of the estimated cost of capacity based on their forecast demand relative to aggregate forecast demand in the charging period;
- This estimated payment is divided into monthly amounts based on the historic proportion of annual consumption that falls in each month and is paid in each month; and
- After the 12 month period has elapsed there are resettlements based on actual costs and actual demand for this period.

5.5.11 The fees payable to generators in GB are similarly profiled so that cash flows are approximately equal in each month.

5.5.12 An alternative approach would be to profile option fees payable to generator so that they only occur in months in which demand is charged for the CRM.

Difference payments and incentive payments

5.5.13 At times of scarcity or near scarcity, capacity providers will make difference payments, and may also make or receive incentive payments for performance. These payments can:

- Be passed back to Suppliers in proportion to their demand at the time when the difference and/or incentive payments arise; or
- Be passed through to Suppliers in proportion to the demand over some other period such as the charging period for option fees - so that they are effectively serve as on offset to the normal charges.

5.5.14 We note that the first of these approaches (matching payments to the trading periods in which the payments arise) has the attraction that, for the difference payments, it more closely corresponds to a hedge against energy prices in the reference market exceeding the strike prices in the option for the proportion of total demand covered by Reliability Options. Generators (or other capacity providers) are likely to be unwilling to offer hedges during these events - as they need the energy revenue to cover the difference payments under the Reliability Options.

5.5.15 It is conceivable that the overall CRM is design such that net payments from capacity providers during a period of scarcity or near scarcity could exceed those required to hedge 100% of demand. Should this happen, the surplus may need to be re-distributed to Suppliers as a discount to subsequent option fees.

5.6 CREDIT COVER

5.6.1 The arrangements discussed in this paper assumed that all parties (principally Suppliers and capacity providers) will make the payments required of them under the terms and conditions. It is always possible that a party will default on their payment obligations, leading to a cash short-fall in the CRM. The risk of such a cash-shortfall can be (and typically is) reduced by requiring each party to provide credit cover that would be used to cover any shortfall in its payments.

5.6.2 In general, credit cover should be set at a level that would cover the maximum exposure to a defaulting party. This is consistent with the approach currently taken in determining levels of Supplier credit cover required under the Trading and Settlement Code[61].

[61] See http://www.sem-o.com/Publications/General/Credit%20Cover%20Overview.pdf for overview of current approach

5.6.3 Whilst the level of credit cover which a Supplier has to provide may change, if for instance, there is a move to concentrate Supplier charges on peak demand, the general principles could remain the same. However, there may be a requirement to introduce credit cover for capacity providers.

Should capacity providers also furnish credit cover

5.6.4 Capacity providers will make payments into the CRM at a number of times. These will depend on the exact design of the CRM, but is likely to include:

- Difference payments, when the reference price exceeds the strike price for the RO. These payments will be volatile, and may be hard to forecast ex ante; and
- Payments that may arise out of performance incentives.

5.6.5 In principle, these payments should be subject to credit cover requirements in a similar manner to payments from Suppliers. The key difference for capacity providers is that the level of credit cover should be based on a capacity provider's *net* payments. That is the payments it would make into the CRM (e.g. from difference payments) *less* the payments it would receive from the CRM (e.g. from option fees).

5.7 EXCHANGE RATE RISK

5.7.1 There are two currencies within the I-SEM price zone. Ireland uses the Euro, whilst Northern Ireland uses the Pound Sterling. This introduces a risk that the exchange rate at the time payments are made will be different to that when the costs were incurred (i.e. at the time of the capacity auction, or of physical delivery

5.7.2 The exchange rate issue exists in the current (SEM) market. However, the level of potential exchange rate exposure is much greater for capacity providers in the I-SEM than the SEM. The auctioned products will be much longer term- potentially up to fifteen years, whereas SEM capacity payments are set for one year only.

5.7.3 The SEM adopts the following solutions:

- **Capacity Payments:** The SEM includes capacity payments to be made to Generators, with the cost of these payments being recovered from Suppliers. The total level of these payments is determined ex-ante on an annual basis, and all payments are made based on a fixed exchange rate for the year. The market will face a gain or loss in respect of any exchange rate variations between the time the total level of payments was determined, and when the payments were made.

- **Energy Payments:** SEM Energy payments are determined in €, and converted to £ based on the exchange rate at the cut off time for bid submissions in respect of a trading day (EA1 Gate Closure). Actual payments happen at a later date, meaning that market will face a gain or loss in respect of any exchange rate variations between the relevant EA1 gate closure and the time of actual payments.

5.7.4 A similar approach is suggested for energy payments in the I-SEM with a minded to position that the costs of exchange variations should be borne, in the first instance, by market operators and then charged as a tariff to Suppliers.[62]

5.7.5 We see no reason to change the above approach for the I-SEM CRM. Exchange rate variations are a genuine cost of operating a market across two currencies. This cost has to be borne by the market in some way, with only two options:

- **Borne by market:** the exchange rates are fixed at the time participants commit (e.g. by submitting a binding bid). Any exchange rate gain or loss is then taken by the market operator (currently SEMO) and recovered as part of its costs. This is the approach used in the current SEM.
- **Born by participant:** the market is priced, and makes payments, in one currency (e.g. €). Parties that incur costs in the other currency carry the cost of the exchange risk.

5.7.6 The latter of the above options introduces an arbitrary distortion to competition between providers in Ireland and Northern Ireland, without necessarily reducing the cost of managing the currency risk. This distortion is arbitrary, as the choice of currency for the market is, itself, arbitrary:

- If the market is priced in £, Ireland participants will carry a cost of managing a currency risk, whilst Northern Ireland participants will not.
- If the marker is priced in €, Northern Ireland participants will carry a cost of managing a currency risk, whilst participants in Ireland will not.

5.7.7 We believe that the application of the SEM approach to Capacity Payments means:

- The exchange rate for option fees should be fixed at the time providers submit their bids to the capacity auction.; and
- The exchange rate for any difference payments or incentive payments should be fixed at the same time as it is fixed for the relevant energy market (e.g. at the time bids are submitted to the Day Ahead Market).

5.7.8 We note that this approach places exchange risk with a central agent - such as the market operator. For the "long term" currency risk (associated with option fees) that

[62] Section 8 of SEM-15-011, "Energy Trading Arrangements Detailed Design, Building Blocks Consultation Paper"

agent would be able to trade in forward markets to manage the currency risk, however is not clear:

- That the agent would have the necessary treasury function to carry out this forward currency trading; or
- Whether capacity providers could manage this risk at a lower cost.

5.8 SUMMARY OF QUESTIONS

5.8.1 The SEM Committee welcomes views on all aspects of this section, including:

A) Whether the recovery of CRM option fees from Suppliers should be on a flat, profiled, or focused basis.

B) Whether the Supplier credit cover arrangements for the I-SEM CRM should be broadly similar to those under the SEM, and whether / what credit cover arrangement should be introduced for capacity providers.

C) Whether the costs of exchange rate variations (arising from differences in the €/£ exchange rate at the time capacity is procured and its subsequent delivery) should be borne by capacity providers or mutualised across the market.

6. INSTITUTIONAL FRAMEWORK

6.1 INTRODUCTION

6.1.1 The SEM Committee published a consultation Paper on 6 March 2015 setting out the proposed institutional arrangements and key roles and responsibilities for the establishment and operation of the I-SEM[63]. As set out in the Roles and Responsibilities Paper, the overall governance for the I-SEM will be based on overarching European regulations and guidelines and legislation in Ireland[64] and Northern Ireland[65].

6.1.2 In line with the governance arrangements for the current energy market and capacity mechanism in the SEM, we intend that the new arrangements for the capacity mechanism will be implemented through market codes and other contracts. These will set out the detailed rules for registration, participation, pricing, and settlement of capacity payments and charges. These rules will be ultimately overseen and approved by the SEM Committee.

6.1.3 These detailed, codified rules will be underpinned as appropriate through existing or modified licence requirements in both jurisdictions. We expect that the detailed rules for the remuneration of capacity providers that have been successful in the capacity auctions and the associated rules for capacity charges on suppliers will be set out in the revised trading and settlement code[66]. We will develop a set of capacity market rules that will set out the rules and procedures for participation in and prequalification for the capacity. These will include provisions for capacity agreements or other forms of counterparty arrangements that set out the obligations and rights of market participants who have been successful in the capacity auctions.

6.1.4 In this section we set out our plans for the overall institutional framework and governance of the new capacity mechanism including:

- **Roles and Responsibilities:** The planned assignment of roles and responsibilities for the administration of the new capacity mechanism including the capacity auction and settlement of capacity payments and

[63] SEM 15-016, I-SEM Roles and Responsibilities, Consultation Paper, 6th March 2015 http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=5d172226-e065-4bba-9ff9-80512012c885&mode=author

64 See http://www.dcenr.gov.ie/Energy/Electricity+and+Gas+Regulation/I-SEM.htm for proposed legislative changes in Ireland

65 See http://www.detini.gov.uk/index/deti-consultations/consultation_exercises/electricity__single_wholesale_market___northern_ireland__order_2007_.htm for proposed legislative changes in Northern Ireland

[66] The SEM Committee intends to publish an I-SEM Codes Implementation Plan in September setting out the process for changing the existing set of codes for I-SEM implementation, specifically the Trading and Settlement Code.

charges. Consideration is also given to conflicts of interest and synergies regarding the proposed roles of the TSOs and market operator in the administration of the capacity mechanism and mitigation measures for any perceived conflicts such as business separation and market rules and audit requirements.

- **Capacity Market Rules and Codes:** Consideration of options for developing a system of codes and market rules and capacity agreements and counterparty arrangements for the new capacity mechanism
- **Contractual Arrangements:** Consideration of options for contractual arrangements that would set out the rights and obligations of capacity providers who are successful in the capacity auctions. Two options are considered, 1. Contractual Counterparty (separate options model) and 2. Capacity Rules and Capacity Agreements (rules based model).
- **Implementation Agreement:** Consideration of whether an implementation agreement would be required and what relation such an agreement would have with the capacity market rules.

6.2 ROLES AND RESPONSIBILITIES FOR THE CAPACITY MECHANISM

Delivery and Administration of the Capacity Market

6.2.1 In our Roles and Responsibilities Paper (SEM 15-016) the change to a capacity mechanism which is based on a competitive bidding process requires a new set of roles and functions for the TSOs and/or market operator. While the SEM Committee will oversee the design of the capacity mechanism and its implementation through the approval of a set of capacity market and settlement rules, we will require a 'Delivery Body' to lead the implementation.

6.2.2 Capacity Market Delivery Role: It is suggested that the TSOs should carry out this role, which will include :

- **Setting the capacity requirement** (that is the amount to be auctioned based on a pre-defined security standard) including the de-rating of capacity providers as required;

- **Preparation, pre-qualification and operation of auctions** as well as planning the auctions and publishing results;

- Provision to the body responsible for **settlement of data** and auction results necessary to settle capacity contracts and levy charges on market participants;

- **Test providers** to ensure those providers are able to demonstrate their capacity and validate eligibility of parties for secondary trading;

- Maintain a system or central register of **capacity agreements or take on contractual counterparty** to capacity contracts as appropriate.

6.2.3 As is standard in other jurisdictions where capacity mechanisms are implemented (Great Britain, Italy, New England ISO, and PJM) and in line with their statutory duties regarding security of supply, we proposed that the TSOs would be the Delivery Body for the new capacity mechanism in Ireland and Northern Ireland.

Settlement of Capacity Payments and Charges

6.2.4 As well as delivery and administration of the capacity market (i.e. the auction), a single entity will be responsible for the collection of charges and the distribution of payments to capacity providers. This will include the collection of all data necessary for that determination, and the management of disputes relating to that data. Given that the new capacity mechanism is a centralised 'single buyer' model it is important that capacity charges are levied on all metered load. Further details of how we propose the settlement of capacity charges and payments to be designed are set out in Section 5 of this paper.

Minded to position

6.2.5 As set out in our Roles and Responsibilities Paper, our minded position is that the market operator responsible for imbalance settlement in the new arrangements will also be responsible for the settlement of capacity payments and charges.

6.3 CAPACITY MECHANISM RULES AND CODES

Capacity Settlement Rules and Capacity Market Rules

6.3.1 The CRM includes a number of requirements that may require different governance arrangements. Areas specific to CRM that will need to be provided for in the all island legal framework include:

- The guidelines for the delivery body in determining the capacity requirement;
- The prequalification requirements for participation in capacity auctions;
- The guidelines or rules for determining de-rating factors for capacity participants;
- The contract with the Delivery Body and Settlement Agent - including, in each case, how costs are approved and recovered;

- The rules for the capacity procurement process - including the auction rules and any pre-qualification requirements; and
- The rules for determining payments to be made under the CRM.

6.3.2 As stated above, we expect that the detailed rules for the remuneration of capacity providers that have been successful in the capacity auctions and the associated rules for capacity charges on suppliers will be set out in the revised Trading and Settlement Code along with the pricing and settlement rules for the energy trading arrangements. This is in line with the current provisions of the TSC which provides for a system of payments of capacity and corresponding collection of charge for those capacity payments.

6.3.3 In order for capacity providers who are successful in the auctions to receive payment for capacity they will be required to accede to and comply with the terms of the revised SEM Trading and Settlement Code. We intend that the TSC will set out the detailed rules for both payments and charges relating to capacity along with related provisions for settlement for particular classes of market participants if required. Credit cover, currency and other settlement related rules will be provided for in the TSC.

6.3.4 Under the current Capacity Payments Mechanism, the TSC provides for the settlement of payments and charges. The RAs determine the price of capacity (through the determination of the fixed and variable costs of the Best New Entrant Plant) and the TSOs set the capacity requirement to work out the Capacity 'Pot' (the Annual Capacity Payment Sum). The capacity 'pot' is determined four months in advance of its delivery period and distribution to generation and settlement on suppliers is governed by the TSC. No agreements, rights or obligations are provided for other than those in the TSC and or Grid Code.

6.3.5 The new capacity mechanism will require an intermediary step between the determination of the capacity requirement by TSOs and the settlement rules to determine the price of capacity. That intermediate step is an auction process where eligible capacity providers compete for contracts to provide the required capacity. This auction process will lead to a clearing price that will replace the current administrative process for the determination of the price.

6.3.6 Capacity providers that are successful in the auction will enter into a series of contractual commitments that include:

- Their rights to payments for that capacity;
- Their obligations to make payments consistent with the design of the Reliability Option (e.g. when the market reference price exceeds the Reliability Option strike price; and
- For new capacity - obligations to build that capacity as promised.

6.3.7 Figure 6-1 and Figure 1-1Figure 6-2 below illustrate the key elements of the contractual framework for the current (SEM) capacity payments and for the proposed (I-SEM) CRM. The key elements of the proposed framework are then discussed in the following paragraphs.

Figure 6-1: Current Capacity Mechanism

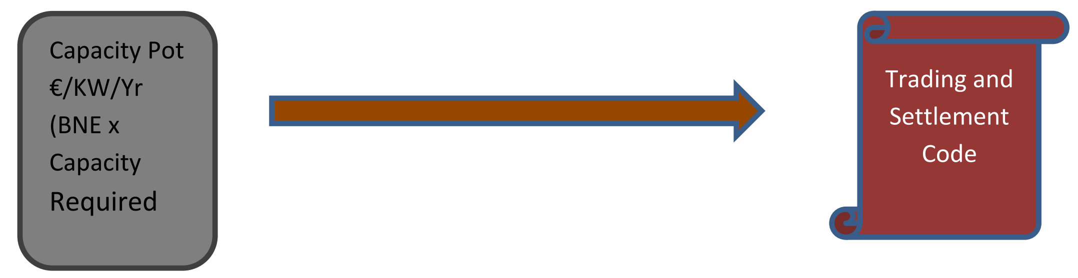
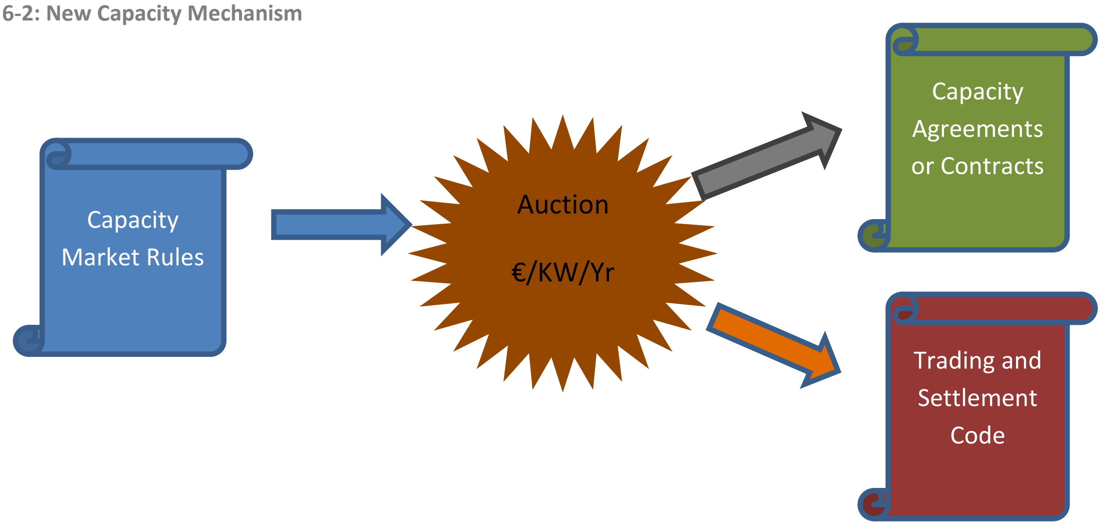


Figure 6-2: New Capacity Mechanism



Capacity Market Rules

6.3.8 In order to implement the new arrangements we intend to develop a set of capacity market rules. These will set out the rules and procedures for participation in and prequalification for the capacity auctions as well as potentially providing the framework under which the TSO enters into capacity agreements that set out the obligations and rights of market participants who have been successful in the capacity auctions.

6.3.9 While the precise licence changes required for the new arrangements have yet to be determined it is our expectation that we will introduce changes to the TSO licences to require them to administer a set of capacity market rules which will be approved by the SEM Committee and to maintain capacity agreements or enter into contracts as required (see section below on contracts/agreements). Should the capacity mechanism be mandatory for existing licence holders in Ireland and Northern Ireland, we will amend generation and supplier licences to require accession to the capacity market rules and prequalification for auction.

Capacity Market Agreement

6.3.10 Capacity Market Agreements will record the key parameters of the capacity agreement, and will either:

- Include the detailed terms relating to the rights and obligations of the capacity provider; or
- Explicitly reference a "master" agreement (such as the Trading and Settlement Code) that contains the detailed terms.

6.3.11 The key parameters that would need to be recorded in the capacity agreement are:

- The start and end date of the Reliability Option
- The (MW) quantity of capacity
- The identity of the physical capacity that is "backing" the Reliability Option
- The identity of the legal entity (i.e. company) that is entering into the Reliability Option
- Whether this is for new build, refurbished or existing plant.
- An explicit confirmation of the key milestone dates that will apply where a Reliability Option is being backed by a new-build or refurbished plant.

Trading and Settlement Code

6.3.12 The Trading and Settlement Code will detail the payments to be determined and administered by the relevant market operator. For example, this could include:

- The arrangements to determine and recover the net costs of Reliability Options from Suppliers;
- The determination of the payments to be made to or by each capacity provider consistent with its Capacity Market Agreement.

Governance of the codes and agreements.

6.3.13 The need for some form of governance arrangements covering changes to the CRM terms and conditions reflects a trade-off between two factors:

- **The need for change:** It is clear that the terms and conditions for the CRM may need to change. For example, to accommodate changes in European legislation relating to electricity markets and competition rules regarding the implementation of capacity mechanisms.
- **The need for stability:** For the CRM to be efficient in attracting investment there needs to be some constraints on the nature of these changes. This is required for investors to have confidence that the terms and conditions that form the basis for the financing of a project will not be subject to unwarranted changes that are detrimental to their financing (which is the basis for the "Stability" I-SEM assessment criteria).

6.3.14 These two factors are resolved by creating a governance framework that constrains the ability of Government, Regulators and participants to change the terms and conditions. For the GB CRM, this constraint comes by stating that any changes to the capacity regulations must be consistent with the following objectives[67]:

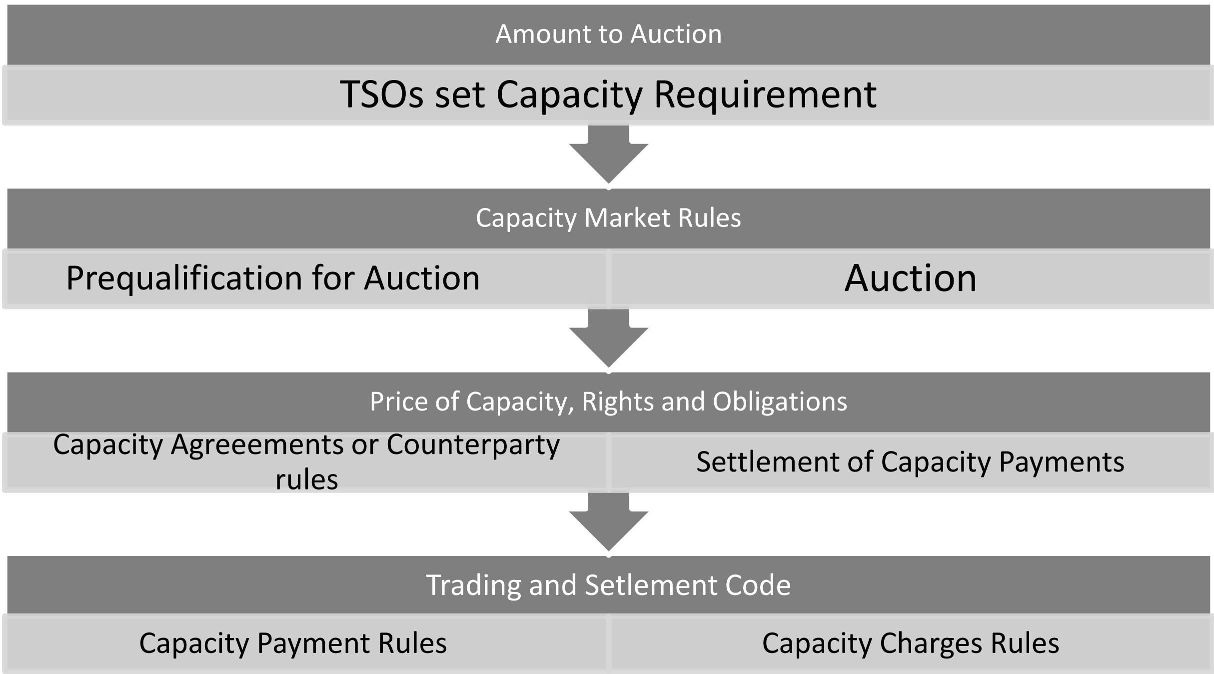
- Promoting investment in capacity to ensure security of electricity supply;
- Facilitating the efficient operation and administration of the capacity market;
- Ensuring the compatibility of capacity market rules with other subordinate legislation under Part 2 of the Act.

6.3.15

[67] Regulation 78 of the GB Capacity Market Regulations

6.3.16 Figure 6-3 below illustrates the proposed governance arrangements for the new capacity mechanism:

Figure 6-3: Institutional Framework for the CRM



6.3.17 We are of the view that the governance arrangements for the capacity mechanism provide the right balance between the objective of stability, practicality and adaptability as described above.

6.4 ASSESSMENT CRITERIA

6.4.1 The assessment criteria that we have considered in proposing the governance arrangements for the new capacity mechanism are:

- **Internal Market and adaptability:** The proposed governance arrangements would ensure compatibility with the internal market by allowing for adaptation of codes and licences to cater for European internal market rules.
- **Stability:** The proposed governance arrangements, in building on the SEM framework of transparent rules based obligations and rights, including the Trading and Settlement Code and a set of capacity market rules and [capacity agreements] provide for stability over the term of the capacity market.
- **Practicality and adaptability:** The proposed arrangements are practical and allow for implementation of the capacity mechanism as per the I-SEM Project timelines.

6.5 COUNTERPARTY CONTRACTS OR CAPACITY AGREEMENTS

Contractual Counterparty or Capacity Agreements

6.5.1 The need to ensure fair competition between new and existing providers means that there may be a rationale for capacity contract lengths of greater than one year to allow new projects to access lower cost financing. Conversely, there may be increased risk for consumers and reduced competition in future auctions from longer term contracts. The issue of contracts lengths will be covered in the Capacity Mechanism Detailed Design Paper 2. Below we consider what the arrangements may need to be put in place to allow for annual or multiannual capacity contracts.

6.5.2 We consider two models for contractual arrangements:

1) The *rules based model* whereby the central body is effectively arranging payment flows between the physical capacity providers and the suppliers. The flows and payments would be codified ex-ante (forming part of the market rules or licences). The central body takes more of an operation/oversight role and not a central counterparty role.

2) The *separate option model* whereby the central body purchases options directly from physical capacity providers through the CRM auction. In one variant of this model the central body is also selling these options on to suppliers. Here the central body is acting as the central counterparty.

These models are outlined in Figure 6-4 and Figure 6-5 below.

Figure 6-4: Rules Based Model

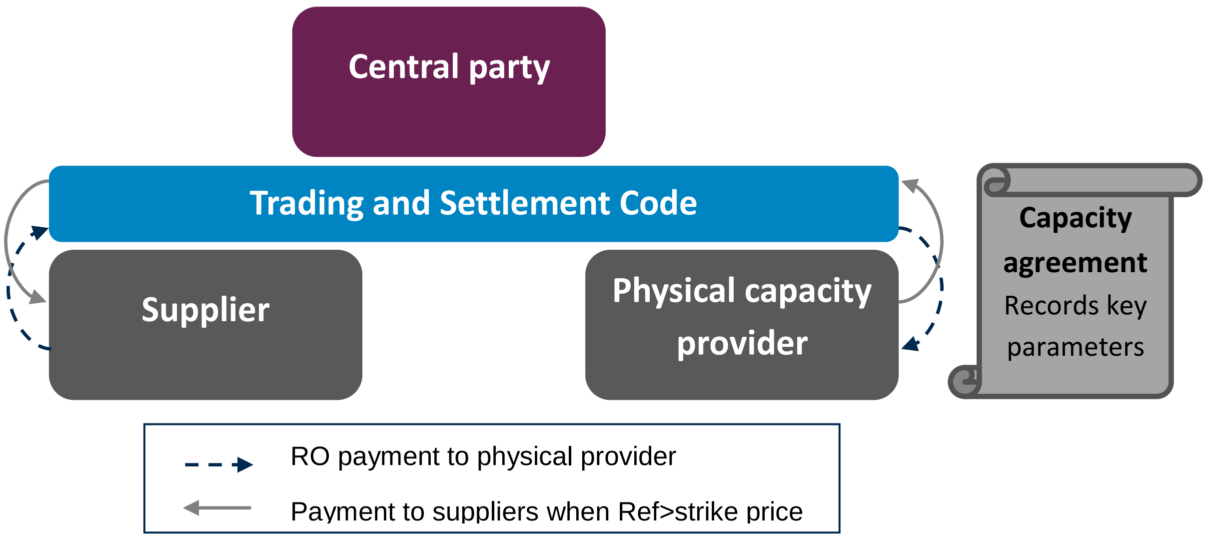
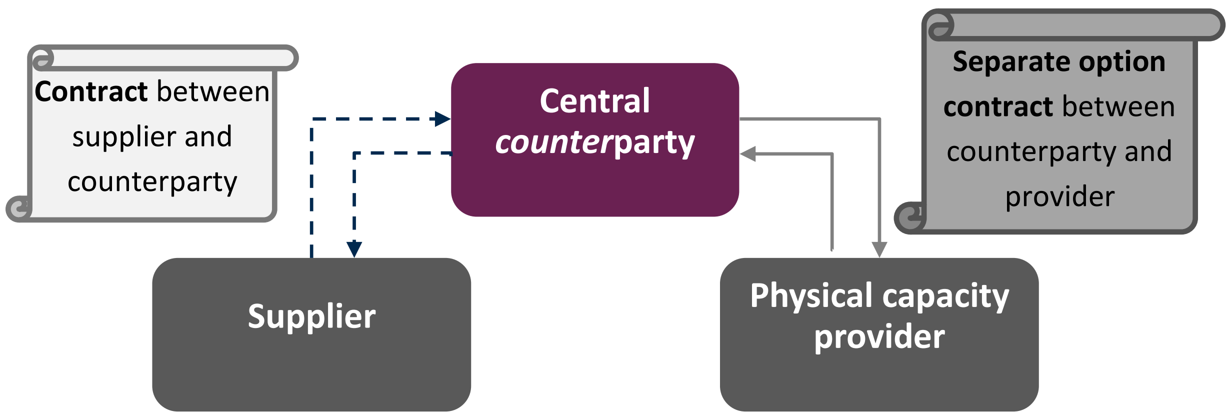


Figure 6-5: Separate Options Model

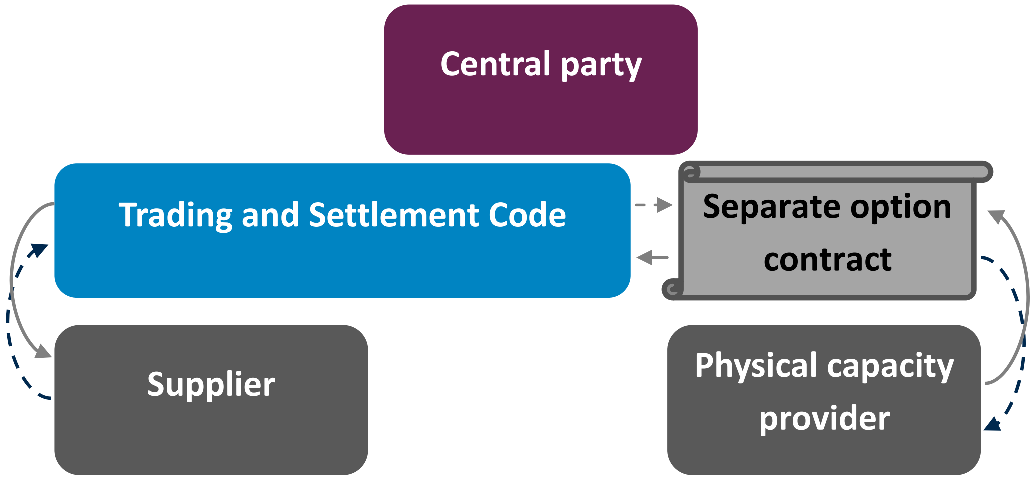


6.5.3 The rules-based model is aligned with the existing CRM in the SEM. This approach would allow for a simpler implementation of the new CRM as the existing arrangements would provide a strong basis for the new mechanism. The Capacity Agreements in this model would record the key parameters for each physical capacity provider.

6.5.4 The separate option model as shown in Figure 6.5 is similar to the current Harmonised Ancillary Services (HAS) arrangements, in which there is a separate HAS Agreement between the TSO and the service provider, and cost recovery takes place via a bilateral agreement between the TSO and Suppliers (TUoS Agreement). From a CRM participant perspective, the separate option counterparty model could provide a formal contract, which may provide greater certainty for investors, particularly where looking to enter into long-term capacity agreements (up to 15 years in the GB example).

6.5.5 Further options can be generated by combining aspects of 1 and 2 that change the risk/exposure for the central body. For example, a separate options based approach could be used where the central body buys RO contracts from participants but the settlement arrangements between the central body and suppliers are codified and therefore rules based. This is shown below in Figure 6-6.

Figure 6-6: Hybrid models



6.5.6 The separate options approaches are similar to ISO New England, GB Contracts for Difference and the Italian Capacity Market where the TSO/ISO is the contractual counterparty to capacity providers who are successful in the auction. The rules-based approach with Capacity Agreements is similar to the GB capacity market implementation, with the TSO maintaining a set of auction rules and capacity agreements and depositing these in a public register, but not acting as a central counterparty.

6.6 SYNERGIES AND CONFLICTS OF INTEREST

6.6.1 Given their existing roles is setting the capacity requirement and overarching responsibilities and for ensuring a security power system there are clear synergies in the TSOs carrying out the delivery role for the capacity auction. However, there may also be concerns around potential conflicts of interest regarding EirGrid's ownership of the East-West Interconnector (EWIC), which is a potential participant in the CRM. This would likely only be an issue if interconnectors directly participate in the capacity auction[68]. A number of decisions taken by the Delivery Body could affect the value EWIC derives from that market, notably:

- **Interconnector de-rating:** The Delivery Body will apply a methodology to determine the extent to which different types of capacity should be re-rated (i.e. have their capacity scaled down) in the capacity market; and

[68] There are various models for how non-I-SEM capacity is included in the CRM, which will vary in their impact on the traded value of EWIC. If the generator led model for cross border capacity is implemented, where GB generation participates in the auction – for example through buying FTRs on Moyle or EWIC – the issue of a conflict of interest would not arise.

- **Award of contracts:** The Delivery Body will operate the auction for the allocation of capacity contracts to providers. In this role, it will have information that is not available to other providers of capacity (e.g. relating to the prices offered by other capacity providers). Again, this is only a concern if the 'interconnector led' approach to cross border capacity participation is implemented.

6.6.2 The design of the cross border capacity participation arrangements will be set out in CRM Detailed Design Paper 2. Depending on the choice of design, there may be a need to address perceived or real conflicts of interest. There are a number of remedies that can be adopted if this conflict of interest is perceived to be an issue and if it is shown to raise costs to consumers. These include:

- **Clear transparent and audited rules:** Limit the extent to which the TSO has discretion in its delivery role (which could be used to the advantage of EWIC), and have independent assurance that it is performing its role objectively;
- **Business separation:** Some form of business separation between EWIC and the TSO's roles in the capacity market may be required. As a minimum, there is likely to be a need for information separation - so that EWIC has no access (beyond that available to other capacity providers) to the information used in the delivery and settlement roles. The degree of business separation if required will be progressed by the RAs through the review of TSOs licences for implementation of I-SEM.

6.7 IMPLEMENTATION AGREEMENT

6.7.1 Mechanisms to procure new capacity typically include measures to manage the period between a capacity provider having its bid accepted, and the relevant capacity coming into operation (the build phase). This normally has two parts:

- **Performance Bond:** A performance bond that is provided at the outset by the bidder, and will be sacrificed in certain defined circumstances (e.g. if the project is abandoned); and
- **Implementation Agreement:** An agreement that allows the Delivery Body to monitor progress in building the capacity, with various step-in rights if the project is delayed or abandoned.

6.7.2 These arrangements are critical when capacity margins are tight, meaning a project delay could lead to a cost to society through higher than desired risk that customers will be disconnected.

6.7.3 Experience from other markets suggests that an implementation agreement should be based around a number of defined milestones, with the developer losing some or all of its performance bond if those milestones are missed. Ideally the nature and timing of these milestones is negotiated between the buyer and developer; however this is difficult to achieve in capacity markets - where the buyer is acting as an agent of the sector. In this situation, it is more normal to define each of the:

- Nature of the milestones;
- Time bounds for achievement of the milestone; and
- Extent to which the performance bond is at risk on those milestones.

6.7.4 This tends to drive to milestones that will be common across all capacity development costs, notably:

- **Substantial Financial Commitment:** When the developer has financially committed to the actual project. This can be measured in a number of ways, but is typically expected to occur relatively quickly following the award of the capacity contract. For the GB Capacity Market:
    - The Financial commitment must be achieved within 18 months of contract award;
    - Financial commitment can be evidenced by having spent at least 10% of the project cost, or through a combination of having entered into one or more contracts for the construction of the capacity, and the Directors of the developer having committed that the plant will be built in time for the start of the period for which it has a capacity contract; and
    - The developer, at its own cost, appoints an independent expert to assess whether the financial commitment milestone has been met.
- **Substantial Completion:** When the relevant capacity is performing at or near the level specified in its capacity contract. There is typically a window of time during which this milestone can be met, with a capacity provider's contract being scaled back to the level of capacity it has managed to demonstrate at the end of that window. For the GB Capacity Market:
    - The time window to demonstrate this milestone runs to 18 months after the first data for which the relevant plant has been awarded a capacity contract. The end of the time window is referred to as the "long stop date"
    - New capacity can partially meet this milestone (and hence start to receive option fees under its contract) when it has demonstrated it can provide at least 90% of its contracted capacity. Its option fees are reduce pro-rate based on its demonstrated capacity, and will increase progressively to 100% of the contracted level provided it demonstrates it can provide that capacity before the long stop date.

- Refurbished capacity has to demonstrate that it can provide 100% of its contracted capacity to receive any of its relevant contracted option fees.

For the I-SEM CRM, we need to consider:

- Whether we need any milestones in addition to "financial commitment" and "substantial completion" milestones;
- How each milestone should be measured;
- what is an acceptable time window for demonstrating each milestone has been met;
- The consequences of failing to meet a milestone.

6.8 SUMMARY OF QUESTIONS

6.8.1 The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on:

A) Are the above outlined governance arrangements suitable for implementation of the I-SEM capacity mechanism?

B) Which options for contractual arrangements are the most appropriate as assessed against the listed criteria?

C) Are implementation agreements required for new entrants participating in the capacity auctions?

7. NEXT STEPS

7.1.1 Interested parties are invited to respond to the consultation, presenting views on the options, proposals and discussion in this paper and where applicable any minded to positions that have been expressed.

7.1.2 The SEM Committee intends to make a decision in October 2015 on the various aspects of the detailed design of the CRM covered in this consultation paper. In reaching this decision we will take into account comments received from respondents to this paper as well as feedback obtained at the public workshops.

7.1.3 A public workshop presenting an overview of this consultation will be held in July 2015 and it is anticipated that a further workshop will be held in advance of the SEM Committee decision in October. Further information on these events will be published at a later date on the All-Island project website.

7.1.4 Responses to the consultation paper should be sent to Brian Mulhern (brian.mulhern@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on 17^{th} August 2015. Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.

8. ACRONYMS

ACER	Agency for the Co-operation of Energy Regulators
ACPS	Annual Capacity Payment Sum
AER	Alternative Energy Requirement
ALFCO	Adjusted Load Following Capacity Obligation
BCoP	Bidding Code of Practice
BM	Balancing Market
BNE	Best New Entrant
CACM	Capacity Allocation and Congestion Management
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
CMU	Capacity Market Unit
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DCENR	Department of Communications, Energy and Natural Resources
DECC	Department of Energy and Climate Change
DSR	Demand Side Response
DSU	Demand Side Unit
EC	European Commission
EEAG	The Environmental and Energy State Aid Guidelines
ENTSO-E	European Network of Transmission System Operators - Electricity
ETA	Energy Trading Arrangements
EU	European Union
FiT	Feed in Tariff
FOR	Forced Outage Rate
FTR	Financial Transmission Right
GB	Great Britain
GB CM	Great Britain Capacity Market
GDP	Gross Domestic Product
GTUoS	Generator Transmission Use of System
GUA	Generating Unit Agreement
HLD	High Level Design
ICE	Intercontinental Exchange
IDM	Intra-Day Market
IED	Industrial Emissions Directive
I-SEM	Integrated Single Electricity Market
ISO NE	Independent System Operator New England
LoLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MB	Balancing Market (Italy)
MGP	Day Ahead Market (Italy)
MRP	Market Reference Price
MSD	Ancillary Services Market (Italy)

MW	Megawatt
MWh	Megawatt hour
NG	National Grid
OCGT	Open Cycle Gas Turbine
ODR	Over Delivery Rate
PER	Peak Energy Rents
PFP	Pay-for-Performance
PJM	Pennsylvania Jersey Maryland
PPA	Power Purchase Agreement
PPB	Power Procurement Business
PSO	Public Service Obligation
ROC	Renewables Obligation Certificate
RP	Reference Price
SEM	Single Electricity Market
SO	System Operator
SoLR	Supplier of Last Resort
SP	Strike Price
SRMC	Short Run Marginal Cost
TLAF	Transmission Loss Adjustment Factor
TSC	Trading and Settlement Code
TSO	Transmission System Operator
US	United States
VoLL	Value of Lost Load

APPENDIX A TSO CAPACITY ADEQUACY STANDARD ANALYSIS

Options for the
I-SEM Capacity Adequ

APPENDIX B CAPACITY MARKET IN NEW ENGLAND

OVERVIEW

The New England Forward Capacity Market, i.e. CRM is based on a RO scheme. The Independent System Operator of New England holds (ISO NE) auctions to procure a volume of ROs equal to the forecast capacity required to meet peak demand plus operating reserve requirements. These ROs entitle the RO holder to a base capacity payment which is determined by the outcome of the auction. In return, they oblige the RO holder to pay a difference payments to Load Serving Entities (the equivalent of Suppliers in the SEM) when the market price exceeds the strike price of the Reliability Option. The strike price is based on the fuel cost of a reference peaking unit. When a scarcity event occurs, there is also an additional performance incentive on capacity providers which result in additional payments to capacity providers who deliver more than the load adjusted RO volume, and deductions from base capacity payments from those capacity providers who deliver less capacity than their load adjusted RO volume.

However, the MW volume difference payment is based on a load following amount, which can reduce the volume of the RO obligation if the scarcity event occurs at a point in time when demand is less than the forecast peak demand requirement.

In this appendix we consider a number of features of this regime, which are a useful benchmark for the design of the I-SEM CRM. These are:

- Capacity requirement;
- Base payments;
- Load following obligation;
- Choice of RO strike price;
- Choice of RO market reference price; and
- Definition of a scarcity event;
- Additional performance incentives, that apply during a scarcity event;
- Caps on performance incentives

We note that in time available we have not been able to validate all material with reference to source documents, and there are some areas of uncertainty remaining.

CAPACITY REQUIREMENT

The capacity requirement is defined as the capacity required to meet peak demand[69] plus operating reserve. In deciding the volume of ROs to procure, ISO NE:

[69] Alternatively called peak load

- Deduct any expected capacity contribution from ineligible capacity from the gross capacity requirement; and
- Takes into account expected de-rating for outages, and hence procures more nameplate capacity than (peak demand + operating reserve) requirement.

Historically, the ISO-NE has used a single value for the capacity requirement but is now planning to introduce a demand curve.

BASE PAYMENTS

Outside scarcity hours, a generator's capacity remuneration would simply be the base payment, determined by the auction outcome. Subject to deduction for difference payments and performance in scarcity periods, the capacity payment is therefore the product of the auction determined price and the bidded available generation

Base Payment = Capacity Auction Clearing Price (in $/MW) × Capacity Supply Obligation (in MW)

Any generator with an RO is required to bid its capacity into the ISO NE day ahead and real time markets, where these bidded availabilities can be adjusted in response to changing events in real time.

LOAD FOLLOWING OBLIGATION

The volume on which difference payments is currently based on Capacity Supply Obligation, i.e. volume of RO sold, without a load following adjustment[70].

However, there is a sort of load adjustment for PER - but it is not applied to the capacity but to the price and is called a scaling factor

We understand that the additional "pay-for-performance" regime does load following through the operation of the "balancing ratio"

STRIKE PRICE

In New England, the Strike Price is set based on the short run marginal cost of a reference peaking unit, the "Peak Energy Rents Proxy Unit". The Strike Price of the RO is defined as:

Strike Price = the heat rate x fuel cost of the Peak Energy Rents (PER) Proxy Unit.

In the US, the heat rate, which is a measure of thermal efficiency, is typically expressed in Btus[71]/KWh. The fuel is oil (ultra low-sulphur No. 2 oil measured at New York Harbour) or gas (day-ahead gas measured at the Algonquin City Gate), whichever is the most expensive.

[70] See Peak Energy Rent (PER) Adjustment Mechanism: FCA-10 and Beyond: Discussion Material, Catherine McDonough, ISO-NE, 13 Nov 2014

[71] Btu= British Thermal Units. 100,000 Btus = 1 therm.

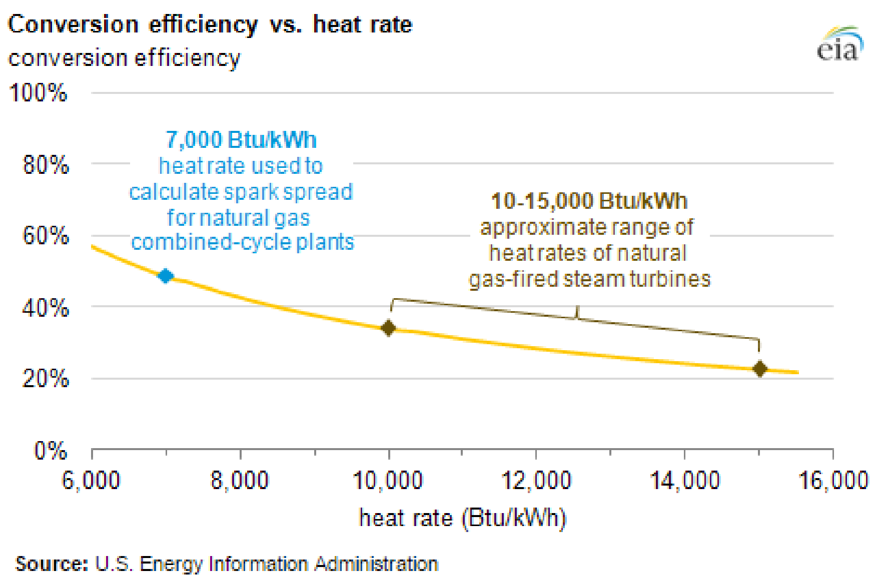
The Peak Energy Rents Proxy Unit is assumed to be an oil or gas-fired generating unit with a heat rate of 22,000 Btu per kWh. As illustrated below in Figure 8-1 the 22,000 Btu per kWh heat rate is well below the typical heat rate of a CCGT. It corresponds to an equivalent to about 15.5% thermal efficiency, since 3,412 Btu= 1 kWh. Volatile Strike Prices need not to be a concern to Suppliers, if other CfDs are appropriately re-designed to dis-apply above the variable Strike Price.

The above formula is intended to ensure that the capacity providers ("resources" in ISO NE terminology) only pay out when they receive scarcity rents from generation -i.e. the energy price exceeds the short run marginal cost of a Peak Energy Rents Proxy Unit. In an energy only market, peak plants would need to be able to retain scarcity rents to cover their (fixed and variable) costs, but in an energy and capacity market, the peak plant should be adequately recompensed through the capacity mechanism.

However, ISO-NE recognise that the 22,000 Btu per kWh is too high, significantly above the actual heat rate of a peaking unit (about 16,000 Btu per kWh)[72], and that the current Peak Energy Rents formula is a poor hedge for load.

The use of a spot gas / oil price could lead to volatile Strike Prices, but if related appropriately to the cost of a genuine peaking unit, would hedge the peak unit and accurately reflect capacity providers' rent. Volatile Strike Prices need not to be a concern to Suppliers, if other CfDs are appropriately re-designed to dis-apply above the variable Strike Price.

Figure 8-1: Conversion efficiency vs. heat rate



Source: http://www.eia.gov/todayinenergy/includes/sparkspread_explain.cfm

[72] See Peak Energy Rent (PER) Adjustment Mechanism: FCA-10 and Beyond: Discussion Material, Catherine McDonough, ISO-NE, 13 Nov 2014

REFERENCE PRICE

The RO in New England use the real time energy prices (or the locational marginal price - LMP), which is calculated ex post as the reference price for RO settlement. In this sense the RO reference price is closer to the BM price than the Day Ahead or intra-day prices employed in the EU target model.

LMP prices are normally based on generator bids so that the difference payments (known as peak energy rents) only apply when energy market LMP prices are very high i.e. higher than the strike price.

However, when a scarcity event occurs in ISO-NE (and, by definition there is insufficient capacity to meet load and operating reserve requirements) the real time energy price is no longer based pure on actual bids but on an administered scarcity price.

Data from a FERC document dated October 2014[73] suggests that the scarcity price is as follows:

- **New England:** The energy offer cap is $1,000/MWh, so in a shortage energy prices should reach that level, and may also reflect the reserve constraint penalty factors for shortages of System Ten-Minute Reserve and System Thirty-Minute Operating Reserve if those products are short as well, so (the energy component of) energy prices could reach $2,350/MWh during an energy shortage ($1000 + $850 + $500).

  However, we understand that New England also plan to introduce a Capacity Performance Rate. In a recent FERC filing ISO New England stated[74], "*For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate*."

- **PJM.** If PJM institutes a voltage drop or is forced to shed load, the penalty factor in the affected area will be the same as a Synchronous Reserve shortage and would currently be $800/MWh. Emergency demand response, when called

[73] See: Price Formation in Organized Wholesale Energy Markets, Docket No: 014-014-000. Staff Analysis of Shortage Pricing in RTO and ISO Markets, Oct 2014.

[74] See letter from ISO New England to the Secretary to the FERC entitled, "ISO New England Inc., Docket Nos. ER14-2419-__, EL14-52-__; 30-Day Compliance Filing to Revise Tariff section III.13.7", dated Nov 3, 2014

upon, leads to the highest possible energy price, which is currently set at $2100 per MWh.

- **ERCOT (Texas)**: Depending on the level of deficiency and actions taken, two shortage pricing methods can come into effect. ERCOT implements administrative shortage pricing when their Security Constrained Economic Dispatch software needs to dispatch regulation resources to provide energy in order to maintain power balance (rather than to provide Regulation Reserve). This administrative pricing is referred to as the Power Balance Penalty Curve and it acts as if it were an energy offer curve for a virtual Generation Resource injecting the amount of the Power Balance mismatch into the ERCOT system.

  On June 1, 2014, ERCOT implemented an Operating Reserve Demand Curve which is used both to price reserves and as a price adder to the real-time energy price. The Operating Reserve Demand Curve is designed to ensure that reserve and energy prices reflect the likelihood that ERCOT will have to shed firm load, measured by the Loss of Load Probability, which can vary from hour-to-hour or day-to-day, and the value of shedding that firm load, the Value of Lost Load. The Operating Reserve Demand Curve ORDC adder therefore is computed as (Value of Lost Load – energy price) * Loss of Load Probability. This curve slopes upwards starting at 5000 MW of reserves before becoming vertical at 2,000 MW and is capped at Value of Lost Load, which is currently set at $9000.

DEFINITION OF SCARCITY PERIOD

A scarcity event is defined as any period of 30 minutes in which available generation < (system demand + operating reserve[75] requirements).

ADDITIONAL PERFORMANCE INCENTIVES

A capacity provider's market revenue consists of three parts:

- A base payment;
- A deduction for peak energy rents – the difference payment; and
- An additional performance payment, which can be a positive amount for over-delivery and a negative amount for under-delivery as described below.

The performance payment would be determined by the capacity provider's performance whenever scarcity conditions occur.

We understand from research conducted by the RA project team, which we have not independently verified that an individual capacity provider's hourly capacity remuneration during scarcity conditions would be determined as follows:

[75] More precisely it is a constraint on operating reserve.

Performance Payment = Performance Payment Rate (in €/MW) × Performance Score (in MW)

where:

Performance Score = Actual MW – Capacity Obligation (in MW) × Balancing Ratio (in %)

where:

Balancing Ratio (in %) = ∑(Load[76] + Reserve Requirement) / ∑Capacity Obligations (both in MW).

The Actual MW is the sum of the capacity providers electricity output (or load reduction) and the reserves that it provides at the time. The capacity obligation is the resource's capacity supply obligation at the time (i.e., what it sold in the auction). This balancing ratio is the load following adjustment.

For instance, suppose a scarcity event occurs during an off-peak period when total load is 4 GW and the reserve requirement is 500 MW. Assume 6 GW of capacity obligations have been sold. Then the balancing ratio would be (4+0.5) / 6 = 75%. Thus, each resource's actual performance would be compared to a reference level of 75 percent of its capacity obligation during this period.

As an example, suppose a resource has an actual MW value of 350 MW and a capacity obligation of 400 MW. If the balancing ratio is 75%, its performance score is +50 MW for this interval (i.e., 350 -400*0.75). Alternatively, if the resource's actual MW is 250 MW during this interval, then its performance score would be –50 MW.

The performance payment rate, together with spot energy payments (less difference payments) and any payments for ancillary services, would give generators the right economic incentives to perform during scarcity periods.

CAPS ON PERFORMANCE INCENTIVES

Performance incentives are subject to the following caps in the ISO NE market. According to the training materials the caps on penalties are limited to approximately:–

- 5% of annual capacity revenues for a shortage event–
- 1% more per hour after 5 hours, for shortage events greater than 5 hours
- Capped at 10% on any day
- Capped at 2.5 months capacity revenues in one month
- Capped at 12 months capacity revenues in one year.

Further research is necessary to confirm the position, but our current understanding is that:

- Penalties do not apply to intermittent power resource; and

[76] Adjusted for contribution of capacity not contracted as ROs

- Demand resources can lose no more than their monthly base payment.

Generators and import resources can manage their exposure through reconfiguration auctions and by bilateral contract which have the effect of reducing or shedding the obligation.

APPENDIX C INCENTIVES AND PENALTIES IN GB

INTRODUCTION

The GB capacity mechanism is not based on a Reliability Option. Payments do not depend on the energy market at all except in the sense that a potential inability to meet demand may trigger a capacity warning (see below).

In GB, renewable resources which are supported by one of the existing subsidy mechanisms (CFD, ROCs, and FiT) are not eligible to participate in the capacity market but their contribution is taken into account in the determination of the capacity requirements to be purchased.

In the GB CRM, capacity providers bid their de-rated capacity in an auction and, if successful receive an agreement[77] which entitles them to be paid for a monthly fee per MW of their supply obligation (their de-rated capacity) subject to performance in periods when capacity is scarce (" a system stress event") during the year of delivery. The volume of capacity agreements and the capacity payment are determined by a descending clock auction, conducted 4 years before the delivery year. Existing capacity and DSM are entitled to one year agreements. Refurbishing plants which meet investment thresholds get 3 year agreements and new plants receive 15 year agreements. Whilst the overall MW capacity obligation and price is determined by the auction outcome:

- The obligation in any given settlement period is scaled to load, similar to the RO volumes in New England; and
- There are performance incentives for under and over-delivery in times of likely or actual system stress.

Whilst the GB mechanism is not based on an RO, and has no strike price or market reference price, some of the features of its design are still relevant benchmarks for the I-SEM CRM design. We note that the investors in the I-SEM will mostly be market participants that are familiar with the GB system, indeed more so than RO based US capacity mechanisms, and may have participated in the 2014 GB auctions. In the remainder if this appendix we discuss the following features of the GB design that are relevant to the I-SEM CRM design:

- Capacity obligation
  - Load following nature of the obligation;
  - Portfolio treatment;
- Design of performance incentives, including caps on performance incentives
- Definition of a system stress event.

[77] Note that in GB there is no private contract with a counterparty for capacity. The agreement is created by the regulatory framework and is represented by an entry on a capacity register held by National Grid.

CAPACITY OBLIGATION

A capacity provider's capacity obligation in MW in a settlement period is based on:

- The capacity obligation acquired from an auction by a Capacity Market Unit (CMU) owned by a capacity provider. However there can be volume reallocation between CMUs within a portfolio based on notices submitted.
- A scaling factor, the Adjusted Load Following Capacity Obligation (ALFCO) for the settlement period, which reflects the ratio of:
    - System demand less the capacity contribution of units that do not have capacity agreements (because they were ineligible or were not successful in the auction; and
    - The total capacity obligations for the delivery year;
    - Note that whilst the CMU's capacity obligation can be scaled down, it can never be scaled up, even if system demand less capacity contribution of units without a capacity agreement (e.g. wind) is greater than CRM capacity obligations- e.g. because the wind is not blowing.
- Adjustments for the delivery of balancing services.

DEFINITION OF SCARCITY EVENT

The rules on penalties and payments for over delivery apply to a settlement period in which there is a system stress event. This is defined as:

- Where the TSO gives a demand reduction instruction to a DNO or where auto low frequency disconnection takes place except there this arises for network reasons (See Rule 8.4.1); and
- A capacity market warning issued by the TSO is in force. Capacity Market warnings are issued either when a demand reduction or auto low frequency disconnection event has already occurred or when an inadequate system margin (<500 MW) is expected to occur at least 4 hours hence.

Penalties and payments for over-delivery apply after a Capacity Market Warning has been issued even though the stress period does not start until 4 hours later[78]

[78] Extract from Section 8 of Capacity Market Rules: During a System Stress Event, a Capacity Provider must deliver the Adjusted Load Following Capacity Obligation of its Capacity Committed CMU, provided that a Capacity Provider has no obligation, pursuant to this Rule 8.5.1:

(a) unless a Capacity Market Warning has been issued with respect to the System Stress Event and the System Stress Event falls four or more hours after the expiry of the Settlement Period in which the Capacity Market Warning is published on the website of the System Operator;

ADDITIONAL PERFORMANCE INCENTIVES

The standard payment for an availability is determined by the auction outcome. The 2014 auction clearing price of £19,400 per MW p.a. – equivalent to a rate of £2.21/ MW per hour of availability. The payment of this amount is subject to "satisfactory performance" which in summary requires that the capacity subject to an obligation be demonstrated a number of times, depending on the CMU type, in the winter of the delivery year. These demonstrations may occur at any time in the winter period[79].

The performance incentives, applicable only in system stress periods work as follows:

- There is a penalty, subject to certain caps, when a CMU's metered production is less than ALFCO and additional payments when it exceeds this ALFCO.
- The penalty rate in £/MW/h of availability is 1/24th of the indexed price for capacity which is expressed as £/MW per year. For the 2014 auction clearing price of £19,400 per MW pa, this implies a penalty rate of £808 per MW/ h of availability (before indexation).
- There is a payment for over-delivery by a CMU in relevant settlement periods based on an Over Delivery Rate or ODR. The Over-Delivery Payment is based on:
    - An ODR which is equal to Min (penalty rate for the CMU, the average market penalty rate); and
    - The production that exceeds ALFCO for the CMU.

This ODR has the effect of providing an additional incentive to return to full availability even if the penalty cap is reached.

Penalties and over delivery payments need not balance and there can be in aggregate a positive or negative sum.

Full details of the settlement calculations are given in Schedule 1 to the Electricity Capacity Regulations 2014.

CAPS ON PERFORMANCE INCENTIVES

There are monthly penalty caps (= to twice the monthly payment) and an annual capacity cap which is stated in the Capacity Market Register. The annual cap is set at 100% of the annual revenue- i.e. a market participant cannot lose over the course of a year by participating

Penalties and caps are applied per CMU and not to the portfolio.

79 Details are set out in Section 13 of the Capacity Market Rules.

COST RECOVERY

Net demand is charged for the cost of the capacity mechanism.

An estimate of the total cost is made before the start of the delivery year.

Each supplier's share of this total cost is determined by their projected share of net demand in the 4pm – 7pm period on winter weekdays between November and February.

There is an ex post correction of the cost of the mechanism and their net demand.

Payment toward the estimated total is made on each month of the year, based on a weighting factor derived from historical demand in each month relative to annual demand.

APPENDIX D INCENTIVES AND PENALTIES IN ITALY

The new capacity mechanism in Italy which is based on Reliability Options is an example of multiple reference markets. In the Italian scheme, which is due to hold its first auction in 2015, the reference market will be both the day ahead market (MGP) and the ancillary service market (MSD)/ Balancing Market(s) (Mb) reflecting the objective of the Italian CRM to incentive reliability and flexibility. In the Italian market holders of ROs will be required to offer into the day ahead, ancillary services and balancing markets.

The mechanism will be voluntary for capacity providers. Plant supported by subsidies and all intermittent plant will not be eligible to participate. De-rated capacity will be determined centrally by Terna, the TSO.

The capacity market will be implemented on an area by area basis where there are major transmission constraints.

Under the Italian CRM rules, volumes accepted in the DAM are settled against the DAM reference price if the option is called. If volumes are not accepted in the DAM and accepted in the ancillary services or Balancing Markets, the option is settled against those markets (pay as bid or pay as cleared) depending on which market its bid was accepted in.

The strike price is based on the plant with the highest marginal costs on the system.